BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

-----In the Matter of the-----	
PUBLIC UTILITIES COMMISSION	DOCKET NO. 7310
Instituting a Proceeding to Investigate the Proxy Method And the Proxy Method Formula Used to Calculate Avoided Energy Costs and Schedule Q Rates of the Electric Utilities in the State of Hawaii.	

DECISION AND ORDER NO. 24086

Filed March 11, 2008
At 9:30 o'clock A .M.

Karen Higashi
Chief Clerk of the Commission

ATTEST: A True Copy
KAREN HIGASHI
Chief Clerk, Public Utilities
Commission, State of Hawaii
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DECISION AND ORDER

By this Decision and Order, the commission: (1) approves, subject to certain conditions and clarifications, the agreements, methods, and procedures stipulated to by the Parties,[1] as reflected in their Updated Stipulation to Resolve

[1]The Parties in this investigative proceeding are: (1) HAWAIIAN ELECTRIC COMPANY, INC. ("HECO"); (2) HAWAII ELECTRIC LIGHT COMPANY, INC. ("HELCO"); (3) MAUI ELECTRIC COMPANY, LIMITED ("MECO") (collectively, the "HECO Companies" or "HECO Utilities"); (4) the DEPARTMENT OF COMMERCE AND CONSUMER AFFAIRS, DIVISION OF CONSUMER ADVOCACY ("Consumer Advocate"); (5) MAUNA KEA POWER COMPANY, INC. ("MKPC"); (6) the HAWAIIAN SUGER PLANTERS' ASSOCIATION ("HSPA"), now known as the HAWAII AGRICULTURE RESEARCH CENTER ("HARC"); and the (7) DEPARTMENT OF THE NAVY, on behalf of the DEPARTMENT OF DEFENSE ("DOD"). CITIZENS UTILITY COMPANY, KAUAI ELECTRIC DIVISION ("KE"), now known as the KAUAI ISLAND UTILITY COOPERATIVE ("KIUC"), was excused as a Party. MKPC and HARC are jointly represented by the same co-counsel.

The commission takes administrative notice of the records on file with the commission.

Proceeding, filed on December 29, 2006; and (2) resolves the issues in which the Parties were unable to reach an agreement.

I.

Background

A.

Predecessor and Other Dockets

1.

Docket Nos. 4569 and 6432

This investigative proceeding has its genesis in two predecessor dockets: (1) Windpower Ass'n of Hawaii, Inc. v. Hawaiian Elec. Co., Inc., Docket No. 4569; and (2) In re Hawaii Elec. Light Co., Inc., Docket No. 6432.

In Docket No. 4569, the commission approved a proxy method and proxy method formula for calculating avoided energy costs and the Schedule Q rate for qualifying facilities ("QF" or "QFs") that supply energy of 100 kilowatts ("kW") or less to the utilities.[2] Thereafter, in Docket No. 6432, HELCO's general rate case: (1) HELCO proposed to revise various components of the

[2] Windpower Ass'n of Hawaii, Inc. v. Hawaiian Elec. Co., Inc., Docket No. 4569, Decision and Order No. 8298, filed on March 18, 1985. Docket No. 4569 arose out of: (1) the electric utilities filing of their initial Schedule Q rates; and (2) the subsequent protests filed by Windpower Association of Hawaii, Inc. ("Windpower"), a non-profit corporation organized for the purpose of representing small power production facilities of 100 kW or less, and several individual members of Windpower. The utilities filed their Schedule Q rates in accordance with Hawaii Administrative Rules ("HAR") § 6-74-22. KE was subsequently dismissed as a party to Docket No. 4569.

proxy method formula; and (2) the commission elected to open a separate, generic docket to examine the calculation of HELCO's avoided energy costs and Schedule Q rate.[3] Ultimately, the commission deferred its generic investigation to this docket.[4]

2.

Wailuku River Hydro

On October 28, 1991, in In re Hawaii Elec. Light Co., Inc., Docket No. 6956, the commission approved the power purchase agreement ("PPA") between HELCO and Wailuku River Hydroelectric Power Company, Inc.,[5] for as-available energy from a 10 MW hydroelectric plant to be constructed on Wailuku River in Hilo, Hawaii.[6] In July 1993, Wailuku River Hydro commenced operations of its run-of-the-river 10 MW hydroelectric facility.[7]

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[3]See Windpower Ass'n of Hawaii, Inc. v. Hawaiian Elec. Co., Inc., Docket No. 6432, Decision and Order No. 10993, filed on March 6, 1991; Order No. 11440, filed on January 22, 1992; and Order No. 11616, filed on May 11, 1992.

[4]Order No. 11617, filed on May 11, 1992.

[5]Wailuku River Hydroelectric Power Company, Inc., is now known as Wailuku River Hydroelectric Limited Partnership ("Wailuku River Hydro"). See letter dated February 21, 2006, from Wailuku River Hydro's counsel to the Federal Energy Regulatory Commission ("FERC"), with copies served on HELCO and the commission ("Wailuku River Hydro's letter to FERC").

[6]The commission also: (1) approved as reasonable the minimum purchase rates based on the avoided cost payment rates for the first quarter of 1991 (the execution date of the PPA), instead of the avoided cost payment rates set during the fourth quarter of 1991, when the commission approved the power purchase agreement; and (2) authorized HELCO to include, in its fuel adjustment clause, the purchased energy costs it incurs under the PPA, for the term of the agreement. See In re Hawaii Elec. Light Co., Inc., Docket No. 6956, Decision and Order No. 11333, filed on

3.

Zond Pacific, Inc.

In In re Maui Elec. Co., Ltd., Docket No. 6742, MECO filed a petition requesting that the commission hold a hearing on the negotiations for a purchased power contract between MECO and Zond Pacific, Inc. ("Zond Pacific"), pursuant to HAR § 6-74-15(c).[8] Zond Pacific proposed to: (1) sell energy to MECO from a 10 MW windfarm facility to be developed by Zond Pacific in Lahaina, island of Maui; and (2) include in the purchased power contract an environmental and security premium pricing structure, which MECO and the Consumer Advocate opposed.

Following an evidentiary hearing and the filing of post-hearing briefs, the commission, on January 7 and 12, 1993, provided the following guidance to the parties, and instructed MECO and Zond Pacific to continue their negotiations of a purchased power contract:

> Our reading of [HAR chapter 6-74], the applicable state statute, and federal rules and regulations is that a utility and an independent power producer are not precluded from negotiating a contract that contains a front-end loaded energy rate and an environmental and security premium pricing structure. Both [Hawaii Revised Statutes ("HRS")] § 269-27.2(c) and HAR § 6-74-22(a)(3) require only that rates for power purchases be not less than 100 per cent of the utility's avoided

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October 28, 1991; see also In re Wailuku River Hydroelec. Power Co., Inc., Docket No. 6779, Decision and Order No. 10839, filed on November 13, 1990 (designating the proposed Wailuku River Hydroelectric Project a QF).

[7]See Wailuku River Hydro's letter to FERC.

[8]Along with MECO, Zond Pacific and the Consumer Advocate were the parties to Docket No. 6742.

cost and not less than the minimum purchase rate.[9] Moreover, HAR § 6-74-15(b)(1) provides that nothing in subchapter 3 of [HAR chapter 6-74] "prohibit[s] an electric utility or any qualifying facility to agree to a rate for any purchase, or terms or conditions relating to any purchase, which differ from the rate or terms or conditions which would otherwise be required by this subchapter."

Although a qualifying facility and a utility may negotiate a contract containing [a] front-end loaded energy rate and avoided external cost pricing structure, any such contract must receive the commission's approval if the utility is to recover any payments it makes under the contract from its ratepayers. In its review of such a contract, the commission must determine, among other things, whether the rate and pricing structure are just and reasonable and in the overall best interests of the general public. In making that determination, the appropriateness of a front-end loaded energy rate and pricing structure in the particular contract is a relevant consideration.

<u>However, the parties are reminded that the commission has before it Docket No. 7310, in which the commission is addressing the issue of avoided cost generically</u>, and Docket No. 7258, in which the commission has directed MECO to engage in integrated resource planning. In both of these dockets, consideration of external costs (environmental and otherwise) in determining a utility's resource cost will be fully explored.[10]

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[9]HAR § 6-74-1 defines "minimum purchase rate" in terms of the utility's avoided energy cost. In the case of a legally enforceable contract between a qualifying facility and the utility, the minimum purchase rate is the utility's avoided energy cost in effect on the date the contract becomes effective. Where there is no contract in excess of one year, the minimum purchase rate is the utility's avoided energy cost in effect on the date the qualifying facility delivers energy to the utility.

[10]In Docket No. 6617, a generic integrated resource planning docket in which the commission fashioned a framework for integrated resource planning by the utilities, the Consumer Advocate argued for the redefinition of "avoided cost" to include, among other factors, monetized environmental externalities and adjustments for non-monetized environmental externalities. In Decision and Order No. 11525 issued in that docket, <u>the commission left to a generic docket on avoided cost [i.e., Docket No. 7310] any changes in the definition of that</u>

In light of these dockets, Zond's proposal to negotiate a power purchase contract that includes an environmental and security premium pricing structure appears to be premature.

In re Maui Elec. Co., Ltd., Docket No. 6742, Decision and Order No. 12118, filed on January 7, 1993, as amended by Order No. 12122, filed on January 12, 1993 (footnotes and text therein retained) (emphasis added).[11]

B.

This Docket

1.

Initiation of the Docket

On May 11, 1992, the commission opened this investigation to examine the proxy method and proxy method formula used by the electric utilities to calculate their avoided energy costs and Schedule Q rates.[12] Under the proxy method, the on-peak and off-peak avoided energy cost rates are calculated based on: (1) the heat rates (i.e., generation efficiencies) of actual on-peak and off-peak generating unit proxies; (2) the electric utility's composite fuel price, which is taken directly from the utility's Energy Cost Adjustment Clause filing; and (3) on-peak and off-peak avoided operations and maintenance

term and promised to fully explore the legal ramifications of changes in the definition of "avoided cost."

[11]There is no indication that MECO and Zond Pacific subsequently agreed on the terms of a purchased power contract for the proposed 10 MW windfarm facility to be built in Lahaina, island of Maui.

[12]Order No. 11617, filed on May 11, 1992.

cost components.[13] The calculation is updated on a quarterly basis using the utility's current composite fuel price.[14]

The Schedule Q rates are based on a weighted composite of the on-peak and off-peak avoided energy cost rates, adjusted by on-peak and off-peak power factor adjustments set in 1985. The Schedule Q rates are adjusted quarterly based on changes in the utility's composite fuel costs.[15] "The schedule Q rate applies to qualifying facilities with capacities equal to or under 100 kw; [the utility's] avoided energy rates apply to qualifying facilities with capacities greater than 100 kw. The interplay between the schedule Q rate and [the utility's] avoided energy costs is that the schedule Q rate is based on the composite of the on-peak and off-peak avoided energy cost rates, adjusted by on-peak and off-peak factors."[16]

In opening this docket, the commission named the HECO Companies, KE, the Consumer Advocate, MKPC, and HSPA as parties to this proceeding. On June 5, 1992, the commission denied intervention to Waimana Enterprises, Inc. and

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[13]See Windpower Ass'n of Hawaii, Inc. v. Hawaiian Elec. Co., Inc., Docket No. 4569, Decision and Order No. 8298, Appendices A (HECO), B (HELCO), and C (MECO).

[14]The electric utilities file their avoided energy costs, also known as their avoided energy cost rates, on a quarterly basis with the commission, pursuant to HAR § 6-74-17(b). The avoided energy cost rates are separately specified for on-peak and off-peak energy deliveries.

[15]Schedule Q rates are rates available to qualifying facilities with design capacities of 100 kW or less. The electric utilities have on file with the commission their Schedule Q rates, in accordance with HAR § 6-74-22(b).

[16]In re Hawaii Elec. Light Co., Inc., Docket No. 6432, Decision and Order No. 10993, at 16.

Wailuku River Hydroelectric Power Company, Inc.[17] On June 8, 1992, the commission granted intervention to DOD.[18]

2.

Issues

On December 29, 1992, the commission issued Stipulated Prehearing Order No. 12100, to govern the issues, schedule of proceedings, and procedures for this investigative docket.[19] Stipulated Prehearing Order No. 12100 identified the following issues:[20]

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[17]Order No. 11663, filed on June 5, 1992. In denying intervention to the movants, the commission held:

> . . . . The motion to intervene in this docket makes no reference to MKPC, which is a party in this proceeding and, like Movants, is a qualifying facility developer. The commission thus finds that the motion to intervene fails to comply with this requirement.
>
> Our own review of the interests of MKPC in this proceeding indicates that MKPC's interests are virtually identical to the stated interests of Movants. We conclude that MKPC will adequately represent the interests of Movants in this docket and that Movants' request to intervene should be denied.

Order No. 11663, at 3. As set forth in the docket record, MKPC is affiliated with Wailuku River Hydro. See MKPC's responses to CA-IR-304 and CA-IR-305.

[18]Order No. 11669, filed on June 8, 1992.

[19]The commission subsequently approved certain revisions to Stipulated Prehearing Order No. 12100.

[20]KE was still a party in this proceeding when Stipulated Prehearing Order No. 12100 was issued by the commission; hence, the reference to "electric utilities" in the stipulated issues. By contrast, the Updated Stipulation limits the scope of the issues to the HECO Companies, instead of to all electric utilities.

1. Whether the proxy method used by the electric utilities to calculate their respective avoided energy costs and Schedule Q rates should be retained, revised or discarded.

2. If the proxy method is retained, whether the proxy method formula should be revised.

3. If the proxy method is discarded, what method should be used by the electric utilities to calculate their respective avoided energy costs and Schedule Q rates.

4. What factors in addition to avoided fuel and generation operating and maintenance ("O&M") costs should be taken into account by electric utilities in determining their respective avoided energy costs and Schedule Q rates, how should any such adders be determined, and what should be the amount of such adders.

5. What are the electric utilities' avoided capacity costs, if any, resulting from their purchase of energy on an as-available basis from qualifying facilities.

3.

Discovery and Position Statements

Following the filing of Stipulated Prehearing Order No. 12100, the parties then engaged in discovery and submitted direct and rebuttal testimonies.

On October 20, 1993, the commission approved the parties' requests to: (1) address the issues without the need for an evidentiary hearing; (2) discuss their respective positions and possibly resolve some of the issues at technical meetings;

and (3) submit position statements on the issues they are unable to resolve by stipulation.[21]

On November 24, 1993, the commission approved the parties' stipulation to excuse KE as a party in this proceeding.[22]

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[21]Order No. 12693, filed on October 20, 1993.

[22]Order No. 12867, filed on November 24, 1993, with the Stipulation to Excuse KE as a Party, attached. The parties, including KE, stipulated in respective part:

> WHEREAS, KE does not use the Proxy Method and the Proxy Method Formula which is the subject of this docket, instead using its own production model, simulation runs, procedures and methodologies for determining its system avoided energy costs;
>
> WHEREAS, KE has never sold more than 500,000,000 kilowatt-hours of electricity annually, the threshold for certain requirements under Title 6 Hawaii Administrative Rules, Chapter 74, Standards for Small Power Production and Cogeneration in the State of Hawaii, Section 6-74-16, and is not reasonably expected to exceed that threshold level of sales for many more years;
>
> . . . .
>
> NOW, THEREFORE, HECO, HELCO, MECO, KE, CA, DOD, HSPA, and MKPC hereby stipulate and agree as follows:
>
> 1. KE should be allowed to be excused as a party in this docket subject to the following understandings and conditions;
>
> a. Until KE has annual electric sales which exceed 500,000,000 kilowatt-hours, it may continue to calculate its avoided energy costs and Schedule Q rates using its own unique production model, simulation runs, methodologies and procedures;
>
> b. After KE's annual electric sales exceed 500,000,000 kilowatt-hours, KE shall be subject to the methodologies and procedures resulting from this docket, as amended by the commission from time to time;
>
> c. When KE becomes subject to the methodologies and procedures approved by the commission in this docket, as it may be amended in the future, if KE or any other party believes certain provisions should not apply to KE or should be modified for application to KE, the party seeking the

On March 2, 1994, the HECO Companies, the Consumer Advocate, MKPC, HSPA, and DOD filed their respective position statements.

4.

Stipulations

On March 4, 1994, the Parties filed their Stipulation to Resolve Proceeding ("Initial Stipulation").[23] On July 16, 2004, the commission instructed the Parties to review and update, if necessary, the agreements, information, and data contained in the Initial Stipulation.[24]

On November 30, 2006, MKPC and HARC jointly filed a "Statement of Position Concerning the Effective Date of Application of Transformer Loss Adjustment ICO HELCO-Wailuku River Hydroelectric Limited Partnership Power

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exemption or modification shall be obligated to initiate a commission proceeding for that purpose and shall bear the burden of proof in any such proceeding;

d. KE's methodologies and procedures in connection with its calculation of avoided energy costs and Schedule Q rates, have no binding or precedential effect on HECO, HELCO, and MECO;

e. KE will continue to consider, but not necessarily adopt in whole or in part, avoided energy cost calculations provided to it by potential Non-Utility Generators ("NUGS") during negotiations for power purchase rates with such NUGS and this stipulation shall not constitute a waiver of any applicable laws.

Stipulation to Excuse KE as a Party, at 1-2 and 4-5.

[23]Stipulation to Resolve Proceeding; and Exhibits A - Q, filed on March 4, 1994.

[24]Order No. 21121, filed on July 16, 2004.

Purchase Agreement."[25] On December 29, 2006: (1) the Parties filed their Updated Stipulation to Resolve Proceeding ("Updated Stipulation");[26] and (2) the HECO Companies, Consumer Advocate, and DOD (collectively, "Respondents") jointly filed their "Statement of Position Re Retroactive Application of Avoided Transformer Losses," in response to the Statement of Position filed on behalf of Wailuku River Hydro.[27]

a.

Parties' Updated Stipulation

In their Updated Stipulation, the Parties note that they entered into the Initial Stipulation, as updated, for the

[25]Statement of Position Concerning the Effective Date of Application of Transformer Loss Adjustment ICO HELCO-Wailuku River Hydroelectric Limited Partnership Power Purchase Agreement; Attachments A - C; and Certificate of Service, filed on November 30, 2006 (collectively, "Statement of Position on behalf of Wailuku River Hydro"). As part of this filing, MKPC and HARC also request "leave to amend or supplement our Statement of Position based upon the final resolution of the Updated Stipulation." Transmittal Letter, filed-stamped November 30, 2006, at 1. The request is denied.

[26]Updated Stipulation to Resolve Proceeding; and Exhibits A - Q, filed on December 29, 2006. The Parties: (1) refer to the Updated Stipulation as the Updated 7310 Stipulation; and (2) filed their Updated Stipulation following the commission's approval of several requests for extension of time. See commission's letter, dated September 16, 2004; Order No. 21703, filed on March 24, 2005; Order No. 22065, filed on October 11, 2005; Order No. 22157, filed on December 5, 2005; Order No. 22510, filed on June 2, 2006; and Order No. 23106, filed on December 5, 2006.

[27]Statement of Position Re Retroactive Application of Avoided Transformer Losses, filed on December 29, 2006, as supplemented on January 5, 2007 (collectively, "Reply").

purpose of simplifying and expediting this proceeding. Moreover, the Initial Stipulation, as updated:

> 1. Represents a negotiated compromise of the matters stipulated to therein, and shall not be deemed to be an admission by any party with respect to any of the matters stipulated to therein.
>
> 2. The Parties expressly reserve their right to proffer, use, and defend different positions regarding matters stipulated to therein in general rate case dockets and in other dockets or proceedings convened to examine avoided cost methodology. At the same time, the Parties agree that the Initial Stipulation, as updated, taken in its entirety and given the evidence in the record, represents a reasonable resolution of the matters compromised to therein.

See Parties' Initial Stipulation, at 5-6; and Parties' Updated Stipulation, at 6-7.

The Parties' Updated Stipulation represents: (1) a partial agreement between the Parties to resolve a majority of the issues; (2) identifies the issues upon which they lack consensus;[28] and (3) includes Exhibits A - Q as attachments.

With respect to the updates made to the Initial Stipulation, the Parties explain:

> The parties have reviewed and updated, as appropriate, the [Initial] Stipulation, referred to herein as the "Updated 7310 Stipulation." The Updated 7310 Stipulation reflects changes in the actual operating conditions of the HECO Utilities, and also includes updates for the passage of time since certain components of avoided cost calculations are adjusted for inflation. Exhibits A-H and J-O have been updated in their entirety and are attached herein.

[28]Specifically, the Parties were unable to reach agreement on the following three sub-issues: (1) retroactive compensation for avoided step-up transmission losses, for Wailuku River Hydro; (2) environmental externalities; and (3) capacity payments for as-available producers of energy.

> Exhibits I, N, P and Q did not require any updates, and are attached herein. Also attached is a blackline version of the Updated 7310 Stipulation which shows the changes made to the [Initial] Stipulation.

Parties' Updated Stipulation, at 2-3.

b.

Parties' Development of the Initial and Updated Stipulations

From the filing of the Initial Stipulation, the Parties were in general agreement that:[29]

1. The proxy method should be discarded, except for the Lanai Division ("Lanai") and Molokai Division ("Molokai") of MECO, which will continue to use proxy methods at this time.

2. Avoided fuel costs should be determined based on a computer production simulation model, except for Lanai and Molokai, which will continue to use proxy methods at this time.

3. Avoided generation O&M costs should include, but not necessarily be limited to, consumables.

4. Adders should be calculated for avoided working cash and avoided fuel inventory.

5. Transmission line losses should be determined on a case-by-case basis.

[29]Parties' Initial Stipulation, at 3-4; and Parties' Updated Stipulation, at 5.

Conversely, the Parties could not reach agreement on:[30]

1. The computer model, or the modeling methodology, assumptions, and data, to be used in calculating avoided fuel costs.

2. The determination of what factors, other than consumables, if any, should be included in determining avoided O&M costs, how such factors should be determined (including consumables) and the amounts of such factors.

3. The determination of what adders (other than avoided working cash and fuel inventory), if any, should be taken into account, how the adders should be determined, and the amounts of such adders.

4. The electric utilities' avoided capacity costs, if any, resulting from their purchase of energy on an as-available basis.

5. The procedures and schedule for the implementation of the new method to be used to calculate the electric utilities' avoided energy costs and Schedule Q rates.

However, as a result of the Parties' technical conferences, the Parties resolved certain of their remaining differences, and agreed to submit position statements on the following issues they identified as unresolved:[31]

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[30]Parties' Initial Stipulation, at 4; and Parties' Updated Stipulation, at 5.

[31]Parties' Initial Stipulation, at 5; and Parties' Updated Stipulation, at 5-6.

1. What are the HECO Companies' avoided capacity costs, if any, resulting from their purchase of energy on an as-available basis.

2. Whether an environmental externalities adder should be included in determining the HECO Companies' avoided energy costs and Schedule Q rates.

3. Whether the HECO Companies' avoided energy costs determined in accordance with the Updated Stipulation should be used in determining the energy rates paid to the following producers with power purchase agreements for firm capacity: (A) Hilo Coast Processing Company ("HCPC"); (B) Puna Geothermal Venture ("PGV"); and (C) the City and County of Honolulu, specifically, the Honolulu Program of Waste Energy Recovery, also known as H-Power.[32]

4. Issues with respect to: (A) the Consumer Advocate's access, at no cost, to the production costing model to be used in calculating avoided fuel costs; (B) the timeframe for selecting the model; and (C) the provision of computer runs to the Consumer Advocate without charge.

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[32]With respect to this third unidentified issue, the following footnote appears in the Updated Stipulation but not in the Initial Stipulation:

> Based on Decision and Order No. 10803, filed October 11, 1990, Docket No. 6616, the remaining parties have agreed that the avoided energy costs determined in accordance with this stipulation should be used in determining the energy rates paid to A&B-Hawaii, Inc., through its division, Hawaii Commercial & Sugar Company ('HC&S'), a producer with a firm capacity PPA.

Parties' Updated Stipulation, at 6 n.2.

Nonetheless, subsequent to the filing of the Parties' Initial Stipulation, the Consumer Advocate has modified its position with respect to Issues No. 1 to No. 3, and the HECO Companies have modified their position with respect to Issue No. 4, based on updated information that was not in existence at the time of the filing of the Initial Stipulation. As a result, the Consumer Advocate and HECO Companies' modified positions are incorporated in the Updated Stipulation.

c.

Stipulated Issues No. 1 and No. 2

With respect to Stipulated Issue No. 1, whether the proxy method used by the HECO Companies to calculate their respective avoided energy costs and Schedule Q rates should be retained, revised, or discarded, the Parties note that two factors have arisen since the adoption of the proxy methodology in Docket No. 4569: (1) the HECO Companies' systems have grown dramatically; and (2) advances in computer software technology have allowed for system simulation models to be readily available and easily utilized to determine avoided costs.

Accordingly, the Parties stipulate that "the proxy method should be discarded (with the exception of Lanai and Molokai, which are small relative to HECO, HELCO and MECO's Maui Division ('Maui'), and for which production simulation models have not yet been developed)."[33] That said, "[o]ne of the benefits of the proxy method, however (i.e., its ease of

[33]Parties' Updated Stipulation, at 7.

application and revision with changing fuel costs), should be taken into consideration with the methodology to be adopted. The new method to be adopted should allow for the ease of updating to reflect changing costs."[34]

As the Parties have agreed that the proxy method should be discarded (with the exception of Lanai and Molokai), they do not address the question of whether the proxy method should be discontinued (Stipulated Issue No. 2).

d.

Stipulated Issue No. 3

With respect to Stipulated Issue No. 3, if the proxy method is discarded, what method should be used by the HECO Companies to calculate their respective avoided energy costs and Schedule Q rates, the Parties stipulate as follows:

1. Avoided fuel costs for the HECO Companies will be determined using a computer production simulation model, with the exception of Lanai and Molokai.

2. Avoided fuel costs for Lanai and Molokai will continue to be determined using proxy methods until a production simulation model is available for such systems.

3. Avoided O&M costs should be determined based on the: (A) proxy generating units for Lanai and Molokai; and (B) generation and firm power purchases avoided as reflected in the production simulations for HECO, HELCO and Maui.

[34] Parties' Updated Stipulation, at 7-8.

Choice of Production Simulation Model

The Parties state that:

1. The goal of this proceeding is to develop a simple and reliable method of estimating avoided energy costs for as-available qualifying facilities and non-fossil fuel producers.

2. The method should not be subject to disputes over analysis or arithmetic calculations.

3. Future disputes, if any, should be over the assumptions that go into the analysis.

In this proceeding, the Parties have utilized different production simulation models in determining avoided fuel costs. That said, the Parties' agreement "[w]ith respect to the production simulation model to be used in determining avoided fuel costs, and the exceptions to such agreement to be submitted to the Commission for decision, are set forth in Exhibit 'A'," of the Updated Stipulation.[35]

Calculation Methodology

The Parties state that two calculation methodologies were considered, the QF-in and QF-in/QF-out methodologies, with the difference in these runs the avoided fuel cost.[36]

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[35]Parties' Updated Stipulation, at 9.

[36]As explained by the Parties:

> Two basic methodologies were considered. The "QF-in" or marginal cost methodology runs the model with QFs available and calculates the marginal running cost for each period. The "QF-in/QF-out" methodology runs the model twice. First, the model is run with the QFs available and the second time without the QFs. The difference in these runs is the avoided fuel cost.

Parties' Updated Stipulation, at 9 (emphasis added).

Avoided Fuel Costs

The Parties' agreement with respect to the production simulation model to be used in determining avoided fuel costs, and the exceptions to such agreement, are set forth in Exhibit A, Production Costing Model, and Exhibit B, Production Simulation and Avoided Fuel Cost, of the Updated Stipulation.[37]

As explained by the Parties:[38]

1. A Production Costing Model ("PCM") Advisory Group was formed for the specific purpose of advising each of the HECO Companies in its choice of a PC-based, commercially available production costing model, capable of appropriately simulating the operation of the Oahu, Hawaii, and Maui island systems.[39]

2. In January 1997, the HECO Companies acquired the P-Month PC-based production simulation model ("P-Month"). The P-Month model has been used by the HECO Companies to perform production simulations to forecast generating unit energy production, fuel consumption, fuel costs, operating hours, start-ups, and variable O&M costs. Specifically, the P-Month

[37]The Parties' exhibits, including Exhibit A and Exhibit B, are attached to this Decision and Order.

[38]Parties' Updated Stipulation, Exhibits A and B.

[39]Parties' Updated Stipulation, Exhibit A, at 1-2. "The members of the PCM Advisory Group included one representative each from Mauna Kea Power, HSPA, the Consumer Advocate, Kauai Electric Company, DOD, HELCO, MECO, and the following departments of Hawaiian Electric Company: Energy Services, Regulatory Affairs, Generating Planning, Production, and System Operations. The PCM Advisory Group was chaired by the representative from HECO's Generation Planning Department." Parties' Updated Stipulation, Exhibit A, at 2.

model has been used for the production simulation results utilized in numerous dockets, including MECO's 1999 test year rate case (Docket No. 97-0346), HELCO's 2000 test year rate case (Docket No. 99-0207), and HECO's 2005 test year rate case (Docket No. 04-0113).[40]

3. On April 7, 1997, the HECO Companies held a PCM Advisory Group Meeting to discuss and evaluate the recommended P-Month model.[41] The PCM Advisory Group was disbanded once the choice of an appropriate model, made solely by the HECO Companies, was made.[42]

As a result of compromise, the Parties stipulate to the following matters with respect to avoided fuel costs (with the exception of MECO's Lanai and Molokai Divisions):[43]

1. Each of the HECO Companies will provide a copy of the calibrated input data set, used to determine the annually updated short-term avoided fuel costs, "to the parties and to entities with power purchase agreements for facilities with a nameplate capacity of greater than one megawatt that incorporate filed avoided energy cost pricing incorporating such avoided fuel cost determined thereby ('the recipients'),[44] at the HECO utilities' expense."[45]

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[40]Parties' Updated Stipulation, Exhibit A, at 2.

[41]Parties' Stipulation, Exhibit A, at 2-25.

[42]Parties' Updated Stipulation, Exhibit A, at 2.

[43]The proxy units for MECO's Lanai and Molokai Divisions are set forth in Exhibit B, paragraph 3. See also Parties' Updated Stipulation, at 9.

2. In the event a party or recipient raises an issue with respect to the production costing model, modeling assumptions, or both, the HECO Companies and the party or recipient agree to informally work together to attempt to resolve such issue.[46]

3. If the HECO Companies and the party or recipient are unable to resolve an issue to their mutual satisfaction, the party or recipient with the unresolved issue may request that the commission resolve the matter by filing a written request with the commission, within thirty days of receipt of such information, attaching the relevant information, and serving the request on the other parties to the proceeding. The other parties shall have the opportunity, at their discretion, to respond to the party or recipient with the unresolved issues, by filing a written response with the commission, and serving the response on the other parties to the proceeding, and the recipient, if applicable.[47]

4. The HECO Companies have agreed to run a reasonable number of scenarios at the request of the other parties or recipients, for the purpose of determining short-term avoided

[44]"For HECO, the recipients at this time would be H-Power, Tesoro [Hawaii Corporation] and Chevron [Corporation]. For MECO, the recipients at this time would be HC&S and Kaheawa Wind Power. For HELCO, the recipients at this time would be Wailuku River Hydro, Hawi Renewable Development, Apollo Energy Corp. and Puna Geothermal Venture[.]" Parties' Updated Stipulation, Exhibit A, at 1 n.1.

[45]Parties' Updated Stipulation, Exhibit A, at 1.

[46]Parties' Updated Stipulation, Exhibit A, at 1.

[47]Parties' Updated Stipulation, Exhibit A, at 1.

fuel costs, for a reasonable charge (based on HECO's cost to do such runs). HECO estimates the charge to be about $55 per hour. HECO also estimates that the development and execution of a single production simulation run will take about sixteen hours and will cost approximately $880.[48]

5. The Consumer Advocate has requested that each of the HECO Companies make the P-Month model, as customized for the HECO Companies' systems, available to the Consumer Advocate. The HECO Companies have agreed to allow the Consumer Advocate access to a copy of the customized P-Month model. The Consumer Advocate shall be responsible for payment to the software vendor for the annual licensing fee for its copy of the model. The HECO Companies have agreed to provide the Consumer Advocate with an orientation session on the customized P-Month model, and such initial assistance may be reasonably requested, without charge to the Consumer Advocate.[49]

If, after obtaining its copy of the customized P-Month model, the Consumer Advocate requests that the HECO Companies run a reasonable number of scenarios for the purpose of determining short-term avoided fuel costs, charges for these runs shall be in accordance with HECO's estimated $55 per hour charge (estimated total of $880 for a single production simulation run).[50]

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[48]Parties' Updated Stipulation, Exhibit A, at 1.

[49]Parties' Updated Stipulation, Exhibit A, at 2.

[50]Parties' Updated Stipulation, Exhibit A, at 2.

6. The parties (other than the HECO Companies) reserve the right to object to the P-Month model due to the cost of obtaining the software for their use. Objections will be forwarded to the commission for its consideration.[51]

7. The QF-in/QF-out method will be used for HECO, HELCO, and Maui, such that: (A) the fuel costs of the utility's resource system without the as-available QFs (QF-out - the base case) are compared to the fuel costs of the system with the as-available QFs in at zero cost (QF-in); and (B) the difference in the fuel costs is the utility's fuel costs avoided by the QFs.[52] The QF-in/QF-out method will be implemented as set forth in the Parties' Exhibit B.

8. The QF-in/QF-out methodology will be used to determine the avoided fuel cost for the on- and off-peak periods for HECO, HELCO, and Maui.[53]

9. The production costing model will simulate, as much as possible, the actual anticipated operation of the generating resources.[54]

10. The new methodology will be implemented four months following the issuance of the commission's written decision approving the Updated Stipulation, including two months for the execution of the production simulations, one month for review by the Parties, and one month for any additional

[51]Parties' Updated Stipulation, Exhibit A, at 2.

[52]Parties' Updated Stipulation, at 9; and Exhibit B, at 1-2.

[53]Parties' Updated Stipulation, at 9-10; and Exhibit B, at 1.

[54]Parties' Updated Stipulation, Exhibit B, at 1.

simulations. The initial updated avoided energy cost rates and Schedule Q rates will go into effect on the 1st day of the month following this four-month period.[55]

11. The model will be updated annually and the resulting avoided fuel costs and production simulations will be available on October 1 of each year for the ensuing year. The fuel price used in the annual runs will be contract prices and/or price estimates, effective September 1. The parties (other than the HECO Companies) and recipients will have the opportunity to review and comment on the avoided fuel costs and production simulation results by November 15.[56] The updated avoided fuel costs will take effect on January 1 for the ensuing year.[57]

12. The HECO Companies will provide the other parties and recipients a copy of the production costing model calibrated input data set, and the updated modeling assumptions used in the production costing model (i.e., an updated Exhibit C).[58] The HECO Companies, upon request, will also provide this information to an entity with a power purchase agreement for a facility with a nameplate capacity of less than 1 MW, and is being paid the

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[55]Parties' Updated Stipulation, Exhibit B, at 1-2.

[56]As previously noted, the HECO Companies have agreed to run a reasonable number of scenarios at the request of the other parties and recipients for a reasonable charge. Requests for additional scenarios shall be made by November 15 to allow the HECO Companies the necessary time to do any additional production simulations. Parties' Updated Stipulation, Exhibit B, at 2.

[57]Parties' Updated Stipulation, Exhibit B, at 2.

[58]Parties' Updated Stipulation, Exhibit B, at 2. The present modeling assumptions for HECO, HELCO, and MECO's Maui Division are set forth in the Parties' Exhibit C, Modeling Assumptions.

avoided energy costs and Schedule Q rates as determined in accordance with this proceeding.[59]

13. The model will include any changes anticipated in the amount of firm capacity available.[60]

14. The avoided fuel costs will be updated monthly to reflect changes in fuel price and firm power energy prices, using as weights the amount of plant generation, as shown in Attachment 1 of the Parties' Updated Stipulation.[61] Purchased energy avoided will be included at its avoided fuel cost.[62] The components of the avoided fuel costs filing will be updated monthly or annually as set forth in the Parties' Exhibit B and Exhibit I, Avoided Fuel Cost Rates Update Schedule.[63]

15. A monthly change of more than five percent (5%) from the anticipated level of available firm capacity resources (due, for example, to an extended forced outage), if known one month prior to the beginning of that month, will require the re-execution of the production simulation for that month.[64]

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[59]Parties' Updated Stipulation, Exhibit B, at 2.

[60]Parties' Updated Stipulation, Exhibit B, at 2.

[61]The forms of the monthly filings, using updated 2005 values for illustration purposes, are set forth in Attachment 1 of Exhibit D (HECO), Exhibit E (HELCO), Exhibit F (MECO's Maui Division), Exhibit G (MECO's Lanai Division); and Exhibit H (MECO's Molokai Division).

[62]Parties' Updated Stipulation, Exhibit B, at 2.

[63]Parties' Updated Stipulation, at 10; and Exhibits B and I.

[64]Parties' Updated Stipulation, Exhibit B, at 2.

16. The avoided fuel costs calculated using this methodology will be applied to energy provided by existing purchased power producers whose payment rates are based on the filed avoided cost.[65]

Avoided O&M Costs

The Parties agree that:

1. Avoided O&M costs will be based upon consumables (per kWh), plus an amortization of the costs of diesel, combustion turbine, and combined cycle overhauls per operating hour, over the avoided operating hours determined using the production simulation for HECO, HELCO, and Maui, or proxy units for Lanai and Molokai.[66]

2. The data used to calculate the avoided O&M costs (in updated 2005 dollars) for steam, diesel, combustion turbine, and firm power generation, are set forth in the Parties' Exhibits J, K, and L.[67]

3. The method used to escalate the O&M costs ($2005), using the Honolulu Consumer Price Index ("CPI"), is set forth in the Parties' Exhibit M, Avoided O&M Escalation. The CPI will be used to annually adjust O&M costs per operating hour and/or per kWh for each type of generating unit until the O&M costs are updated in a general rate case. The percentage of generation

[65]Parties' Updated Stipulation, Exhibit B, at 2.

[66]Parties' Updated Stipulation, at 10.

[67]Parties' Updated Stipulation, at 10-11. Avoided O&M rates for HECO (Exhibit J), HELCO (Exhibit K), and MECO (Exhibit L).

assigned to each type of generating unit will be adjusted when the modeling is updated.[68]

4. The forms of the monthly filing for avoided O&M costs are set forth in Attachment 2 of the Parties' Exhibits D to H.[69]

e.

Stipulated Issue No. 4

Stipulated Issue No. 4 involves the factors in addition to avoided fuel and generation O&M costs that should be taken into account by the HECO Companies in determining their respective avoided energy costs and Schedule Q rates, how any such adders are determined, and the amount of such adders. The Parties stipulate as follows:

Avoided Working Cash

The Parties agree that:

1. An adder will be included for avoided working cash based on the payment lags provided for in the individual PPAs.[70]

2. The methodology utilized to calculate avoided working cash costs is set forth in Attachment 3 of the Parties' Exhibits D to H. The calculation of the purchased energy payment lag is set forth in the Parties' Exhibit N, Calculation of Purchased Energy Payment Lag. The update schedule for the

[68]Parties' Updated Stipulation, at 11.

[69]Parties' Updated Stipulation, at 11; and Attachment 2 of Exhibit D (HECO), Exhibit E (HELCO), Exhibit F (Maui), Exhibit G (Lanai), and Exhibit H (Molokai).

[70]Parties' Updated Stipulation, at 11.

avoided working cash calculation is set forth in Exhibit O, Update Schedule for Avoided Working Cash Calculation for Impact on Fuel and Purchased Energy, and Update Schedule for Avoided Working Cash Calculation for Impact on O&M.[71]

Avoided Fuel Inventory

The Parties stipulate to the following:

> An adder will be included for avoided fuel inventory, based upon the number of days of inventory avoided for each type of fuel by as-available energy purchases. The calculation of avoided fuel inventory costs will be based upon the fuel oil inventory costs and inventory policies approved by the Commission in general rate cases. Fuel inventory will be deemed to be avoided if (and to the extent that) the HECO utility's fuel inventory for a specific type of fuel as determined in its last general rate case is based on a fixed number of days of inventory and the average test year burn rate for the type of fuel. Fuel inventory will not be deemed to be avoided if (and to the extent that) the HECO[] utility's fuel inventory for a specific type of fuel as determined in its last general rate case is based on a fixed number of barrels of fuels, regardless of the test year average burn rate for the fuel.

Parties' Updated Stipulation, at 12.

The methodology used to calculate avoided fuel inventory costs will be as set forth in Attachment 4 of the Parties' Exhibits D to H.[72] The calculation will be updated as set forth in Exhibit P, Update Schedule for Avoided Fuel Inventory Calculations.[73]

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[71]Parties' Updated Stipulation, at 11; Attachment 3 of Exhibits D to H; and Exhibits N and O.

[72]Parties' Updated Stipulation, at 12; and Attachment 4 of Exhibits D to H.

[73]Parties' Updated Stipulation, at 12; and Exhibit P.

Avoided Step-Up Transformer Losses

The Parties agree that, for the QFs that utilize synchronous generators and are metered on the "high side" of the step-up transformer, an allowance will be made for transformer losses. The allowance, as set forth in the Parties' Exhibit Q, Avoided Step-Up Transformer Losses, will be made for the applicable QFs as a "gross-up" to the generation meter reading.[74] Conversely, no allowance will be made for the QFs that utilize induction generators.[75]

The Parties could not agree on whether Wailuku River Hydro should be compensated retroactively back to the filing date of the Initial Stipulation for avoided step-up transformer losses, and request that the commission resolve this disputed issue.

Avoided Transmission Losses

The Parties stipulate that "[t]ransmission losses shall be handled on a case by case basis when presented in a specific contract proposal from a QF."[76]

Application to Existing Power Purchase Agreements

The Parties agree that the avoided energy costs determined in accordance with the Updated Stipulation:

[74]The respective adjustments for avoided step-up transformer losses are 0.34 percent for HECO, 0.50 percent for HELCO, and 0.53 percent for MECO's Maui Division. Parties' Updated Stipulation, Exhibit Q.

[75]Parties' Updated Stipulation, at 12; and Exhibit Q.

[76]Parties' Updated Stipulation, at 13.

1. Will be used in calculating the energy rates paid to the following QFs with PPAs currently in effect with a HECO utility that provide for energy payments based on Schedule Q rates, or the utility's on-peak and off-peak avoided costs for energy filed with the commission: (A) Schedule Q producers; (B) producers with PPAs for as-available energy; and (C) the following producers with PPAs for firm capacity: PGV, HC&S, HCPC, and H-Power.[77]

2. Will not change or otherwise affect the minimum purchase rate or rates applicable to any existing PPA.[78]

Schedule Q

The Parties agree that the Schedule Q payment rates:

1. Will be based on the avoided energy costs determined in accordance with the Updated Stipulation, following the application of the applicable power factor adjustments.[79]

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[77]Parties' Updated Stipulation, at 13-14. "HCPC ceased operations and its PPA was terminated as of January 2005, therefore this issue is moot with respect to HCPC." Id. at 13 n.3.

The Consumer Advocate initially maintained that the avoided energy cost should not apply to PGV and H-Power. The Consumer Advocate subsequently modified its position. As a result, the Consumer Advocate now concurs that the avoided energy cost determined in accordance with this Updated Stipulation should be applicable to PGV and H-Power. The DOD took no position on this issue. "Accordingly, the HECO Utilities, the Consumer Advocate and MKPC/HARC are now in agreement that the avoided energy cost determined in accordance with this stipulation shall also apply to PGV and H-Power." Id. at 14.

[78]Parties' Updated Stipulation, at 14.

[79]Parties' Updated Stipulation, at 14.

2. Are determined by adding the on-peak and off-peak avoided fuel costs to the on-peak and off-peak avoided O&M costs, respectively, and subtracting the on-peak (-$0.12/kWh) and off-peak (-$0.28/kWh) power factor adjustments, respectively. The on-peak and off-peak amounts are time-weighted to determine a single payment rate.[80]

With respect to the power factor adjustment, the Parties stipulate:

> The power factor adjustment reduces the rate paid to Schedule Q producers for purchased energy to compensate the utility for supplying voltage and reactive current support required by inductive generators typical of Schedule Q producers. The values of the adjustment, as determined in Docket No. 4569, were based on the additional fuel consumed to produce kilovarhours and the capital cost of substation capacitor banks. QFs subject to Schedule Q that demonstrate that the power factor adjustment is inappropriate (because the QF does not require voltage or reactive current support) will be permitted to enter into a contract that deletes the adjustment. The applicability of the power factor adjustment will be determined on a case-by-case basis. The HECO Utilities will file revised Schedule Q tariff provisions to comply with the Commission's decision and order in this docket.

Parties' Updated Stipulation, at 14-15.

[80]Parties' Updated Stipulation, at 14.

Environmental Externalities

The Parties disagree on environmental externalities, and request that the commission resolve this disputed issue.[81]

f.

Stipulated Issue No. 5

For Stipulated Issue No. 5, which involves the HECO Companies' avoided capacity costs, if any, resulting from their purchase of energy on an as-available basis from qualifying facilities, the Parties do not agree on whether capacity payments should be paid to as-available energy producers, and request that the commission resolve this disputed issue.

II.

Discussion

The commission, at the outset of its discussion, makes the following observations:

1. KE, which was excused as a party to this proceeding, is now an electric utility cooperative known as KIUC.

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[81]From the outset, the HECO Companies and DOD's position was that there was no basis for the payment of an externalities adder by the electric utilities. The Consumer Advocate initially disagreed, but based on new developments and information, the Consumer Advocate has changed its position. The Consumer Advocate now believes that: (1) no externalities variable should be included in the calculation of the subject avoided costs; and (2) the consideration of externalities is an issue that is appropriately addressed in the HECO Companies' IRP proceedings. Moreover, the Consumer Advocate reserves the right to present its position on externalities with respect to integrated resource planning in the HECO Companies' IRP planning process and Advisory Group meetings. <u>See</u> Parties' Updated Stipulation, at 15-16.

2. HELCO's PPA with HCPC terminated on December 31, 2004.[82] HC&S continues to provide firm power to MECO,[83] H-Power continues to provide firm power to HECO,[84] and PGV continues to provide firm power to HELCO.[85]

3. The parties in In re Public Util. Comm'n, Docket No. 94-0226, unanimously supported the commission's approval of the Initial Stipulation:[86]

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[82]See HELCO's Adequacy of Supply Report, dated March 15, 2005.

[83]See MECO's Adequacy of Supply Report, dated February 27, 2007.

[84]See HECO's Adequacy of Supply Report, dated February 27, 2007.

[85]See HELCO's Adequacy of Supply Report, dated January 30, 2007.

[86]On April 11, 1994, the commission, in Docket No. 94-0226, instituted a proceeding to investigate the development and use of renewable energy resources within the State, in response to a Senate concurrent resolution. See In re Public Util. Comm'n, Docket No. 94-0226, Order No. 13441, filed on August 11, 1994.

The parties in Docket No. 94-0226 consisted of the HECO Companies; KE; the Consumer Advocate; Counties of Hawaii, Kauai, and Maui; State Department of Business, Economic Development & Tourism; Energy Resource Systems; State Senate Committee on Science, Technology and Economic Development; Hawaiian Commercial & Sugar Co.; Inter Island Solar Supply; Kahua Ranch, Ltd.; Makani Uwila Power Corp.; Pacific International Center for High Technology Research; Puna Geothermal Venture; RLA Consulting; TRM/Wind Energy International, Inc.; Waimana Enterprises, Inc.; Zond Pacific, Inc.; and a professional engineer.

On February 20, 1996, a report entitled Strategies to Facilitate the Development and Use of Renewable Energy Resources in the State of Hawaii, dated February 1996, was submitted to the State legislature. The report includes as an attachment the parties' "Collaborative Document - Renewable Energy Resource Investigation," dated November 3, 1995, which sets forth the parties' strategies and recommendations. The parties' collaborative document pre-dates the filing of the Updated Stipulation.

[Strategy 1.c.1]

Reduce the uncertainty regarding avoided costs.

DISCUSSION:

There are pending PUC dockets regarding the determination of short-run avoided energy costs for as-available resources (Docket No. 7310) and of long-run avoided costs for firm capacity resources (Docket No. 94-0079). Resolution of these dockets by the PUC will substantially reduce any uncertainty regarding the determination of avoided costs.

VEHICLE: Resolution of pending PUC dockets regarding the determination of short-run avoided energy costs for as-available resources (Docket No. 7310) and of long-run avoided costs for firm capacity resources (Docket No. 94-0079).

AGENCY: PUC.

. . . .

[Strategy 1.f.1]

The PUC should approve the stipulated agreement of the parties and resolve the outstanding issues in Docket No. 7310.

DISCUSSION:

The PUC has conducted a contested case proceeding, Docket No. 7310, to investigate the methods used to determine the quarterly short-term avoided costs used as the basis for payment by the utilities for as-available generation. The parties in the docket have reached a stipulated agreement on most issues and have filed statements of position regarding outstanding issues. The parties were not able to reach agreement regarding the inclusion of externality costs or avoided capacity costs (under special conditions) in the calculation of quarterly short-term avoided costs. The PUC has not yet issued an Order resolving this docket.

The issues addressed in Docket No. 7310 pertain only to regular short-term avoided cost filings. Resolution of these issues would not prohibit utilities or resource developers from using other methods of determining avoided costs in negotiating a power purchase agreement as long as the costs used could be demonstrated to the PUC to be just and reasonable.

Resolution of the issues raised in Docket No. 7310 would clarify many details regarding the calculation of the quarterly short-term avoided costs filed with the PUC. Utilities and resource developers would still be free to use alternate methods of determining reasonable prices in negotiating power purchase contracts.

VEHICLE: Docket No. 7310

AGENCY: PUC

In re Public Util. Comm'n, Docket No. 94-0226, Collaborative Document - Renewable Energy Resource Investigation, dated November 3, 1995, at 1.c-2 and 1.f-3.

A.

Stipulated Issues No. 1 and No. 2

The Parties have reached agreement on Stipulated Issue No. 1: Whether the proxy method used by the HECO Companies to calculate their respective avoided energy costs and Schedule Q rates should be retained, revised, or discarded. Specifically, the Parties agree that the proxy method should be discarded, except for Lanai and Molokai.

The proxy method was adopted by the commission in 1985, in Docket No. 4569. The Parties, in agreeing to discard the proxy method (except for Lanai and Molokai), note that since 1985, the HECO Companies' systems (except for Lanai and Molokai) have grown dramatically, and advances in computer software technology have allowed for system simulation models to be readily available and easily utilized to determine avoided costs. In essence, it is the Parties' consensus that the proxy method (with the exception of Lanai and Molokai, which are small relative to HECO, HELCO, and Maui, and for which production simulation models have not yet been developed) is dated.[87]

The commission finds that the discontinuance of the proxy method, except for Lanai and Molokai, is consistent with the stakeholders' interests of utilizing computer production simulation models in determining avoided energy costs. Hence, the commission approves the Parties' agreement for Stipulated Issue No. 1.

As the proxy method will be discontinued for HECO, HELCO, and Maui, the question of whether the proxy method should be discontinued (Stipulated Issue No. 2) is rendered moot for these entities. With respect to Lanai and Molokai, the commission approves the Parties' agreement to continue the proxy method for Lanai and Molokai, without change, as production simulation models have not yet been developed for such systems.

[87]See, e.g., HECO's Statement of Position, at 17-18 (while the avoided energy cost rates are adjusted quarterly based on changes in the electric utility's composite fuel prices, the formulas have not been adjusted since 1985) and 49 (the proxy method is outdated).

B.

Stipulated Issue No. 3

The Parties have reached agreement on Stipulated Issue No. 3: If the proxy method is discarded, what method should be used by the HECO Companies to calculate their respective avoided energy costs and Schedule Q rates.

As characterized by Respondents, the Updated Stipulation, if approved by the commission:

> . . . will substantially change the manner in which filed avoided energy cost rates are determined for the HECO Utilities. Filed avoided energy cost rates are used to determine the energy rates paid to most as-available energy producers having power purchase agreements ("PPAs") with the HECO Utilities, and to several firm capacity producers having PPAs with the HECO Utilities. The parties are in agreement that, with the exception of Lanai and Molokai (which are small relative to HECO, HELCO and MECO's Maui Division, and for which production simulation models have not be been developed), (1) the current proxy method should be discarded, (2) avoided fuel costs for the HECO Utilities will be determined using a computer simulation model, and (3) avoided O&M costs should be determined based on the generation and firm power purchases avoided as reflected in the production simulations.

Respondents' Reply, at 2-3.

In effect, the Parties agree: (1) to discard the proxy method and utilize P-Month, a PC-based production simulation model, to calculate avoided fuel costs for HECO, HELCO, and Maui; and (2) that avoided O&M costs will be calculated based on the generation and firm power purchases avoided, as reflected in the production simulations for HECO, HELCO, and Maui.

As noted by the Parties, the P-Month model: (1) was selected based on input from the PCM Advisory Group; (2) has been used in calculating the production simulation results in general rate cases involving MECO, HELCO, and HECO; and (3) will simulate, as much as possible, the actual anticipated operation of the generating resources. Moreover, the HECO Companies have agreed to: (1) run a reasonable number of scenarios at the request of the other parties or recipients for the purpose of determining short-term avoided fuel costs, subject to a reasonable, cost-based charge; (2) provide the other parties and recipients a copy of the production costing model calibrated input data set, and the updated modeling assumptions used in the production costing model (i.e., an updated Exhibit C); and (3) make the P-Month model, as customized for the HECO Companies' systems, available to the Consumer Advocate.

Upon review, the P-Month model appears to meet the Parties' stated goal of developing a simple and reliable method of calculating avoided energy costs. Accordingly, the commission: (1) accepts as reasonable the Parties' agreements for resolving Stipulated Issue No. 3; and (2) approves the Parties' agreements, procedures, and methods for Stipulated Issue No. 3. In approving said compromises, the commission clarifies that written requests submitted to the commission to resolve disputed matters, as reflected in the procedures set forth in the Parties' Exhibit A, shall comply with the commission's procedures governing the filing of complaints, HAR chapter 6-61, subchapter 5.

C.

Stipulated Issue No. 4

The Parties have reached partial agreement on Stipulated Issue No. 4: What factors in addition to avoided fuel and generation operating and maintenance costs should be taken into account by the HECO Companies in determining their respective avoided energy costs and Schedule Q rates, how should any such adders be determined and what should be the amount of such adders. MKPC/HARC and Respondents, however, disagree on the resolution of two sub-issues: (1) retroactive compensation for avoided step-up transmission losses for Wailuku River Hydro; and (2) environmental externalities.

1.

Partial Agreement

The Parties agree that: (1) adders will be included for avoided working cash and avoided fuel inventory; (2) for QFs that utilize synchronous generators and are metered on the "high side" of the step-up transformer, an allowance for transformer losses (except for QFs that utilize induction generators); (3) avoided transformer losses will be handled on a case-by-case basis; and (4) the avoided energy costs determined in accordance with the Updated Stipulation will not change or otherwise affect the minimum purchase rate or rates applicable to any existing PPA. The Parties have also reached agreement on the procedures and methods: (1) to calculate the agreed-upon adders; and (2) for the Schedule Q payment rates.

The commission finds that working cash, fuel inventory, step-up transformer losses (high-side), and transmission losses constitute incremental costs that the HECO Companies will avoid by its purchasing of energy from a QF. Thus, such costs are appropriate adders that should be taken into account in calculating the HECO Companies' avoided energy costs.

Upon review, the commission accepts as reasonable, and thus, approves, the Parties' above-referenced agreements, procedures, and methods that partially resolve Stipulated Issue No. 4.

The Parties also agree that the avoided energy costs determined in accordance with the Updated Stipulation will be used in calculating the energy rates paid to the following QFs with PPAs currently in effect with a HECO utility that provide for energy payments based on Schedule Q rates, or the utility's on-peak and off-peak avoided costs for energy filed with the commission: (1) Schedule Q producers; (2) producers with PPAs for as-available energy; and (3) the following producers with PPAs for firm capacity: Hawaiian Commercial & Sugar Company, H-Power, and PGV.

In support of the Parties' agreement to apply the avoided cost rates developed and approved in this docket to HC&S, H-Power, and PGV, three firm capacity producers with existing PPAs with MECO, HECO, and HELCO, respectively, the HECO Companies contend:[88]

[88]See HECO Companies' Statement of Position, filed on March 2, 1994 ("Statement of Position"), Section VI, at 47-60.

1. The PPAs with HC&S, H-Power, and PGV all provide for energy payment rates based on the filed on-peak and off-peak avoided energy costs calculated in accordance with HAR chapter 6-74. The commission's approval of the Parties' compromises and methods, as reflected in the Updated Stipulation, will change the calculation of the HECO Companies' filed avoided energy costs, but not the PPAs. Thus, the new rates will apply to these firm capacity producers unless the commission explicitly instructs otherwise, and the HECO Companies are not aware of any valid reason to limit the applicability of the new avoided energy cost rates.

2. There is no evidence that the new avoided energy cost rates will duplicate costs included in the determination of the capacity payments to HC&S, H-Power, or PGV.

3. The new avoided energy cost rates will not be significantly higher than the energy payment rates currently payable to these firm capacity producers. The avoided energy costs determined using the new method should be lower on the islands of Maui (HC&S), Oahu (H-Power), and Hawaii (PGV), reflecting the fact that the proxies used in the existing proxy method were established in 1985, and are now outdated. Thus, the new rates better reflect the HECO Companies' systems, and are more appropriate than the current rates payable to these firm capacity producers, which are based on the proxy method.

4. In addition, the minimum purchase rates, which currently determine the avoided energy rates payable to HC&S, H-Power, and PGV, will not be affected. Thus, the application of

the new avoided energy cost rates to these firm capacity producers may not even immediately change their energy payment rates.

The HECO Companies' represent that such prospective application is consistent with the terms of the existing PPAs:

> Avoided Energy Cost
>
> . . . .
>
> Q. To whom are the Companies' proposed determination of avoided energy costs applicable?
>
> A. The Companies are proposing to apply the proposed avoided energy payment rates to all existing purchase energy producers whose contracts call for payment based on the avoided energy rates filed with the Commission, including existing firm capacity contracts such as those with [H-Power, HCPC, PGV, and HC&S].
>
> Q. Why are the Companies proposing to continue to pay firm capacity producers under the short-term avoided energy rates filed with the Commission?
>
> A. The Companies are proposing to continue this method of energy payment in keeping with the terms of the existing contracts.
>
> Schedule Q Rates
>
> . . . .
>
> Q. To whom would the Companies' proposed determination of Schedule Q rates be applicable?
>
> A. The Companies are proposing to apply their proposed Schedule Q payment rates to all existing producers whose contracts call for payment based on the avoided energy rates filed with the Commission. Future Schedule Q contracts would also be based on the proposed Schedule Q rates.

HECO T-1, at 11-14.

The PPAs reviewed by the commission generally include provisions that utilize the electric utility's short-run avoided energy cost rates on file with the commission as the basis for calculating the agreed-upon purchased energy rates between the utility and independent power producer.[89] Some of the PPAs also include provisions that explicitly incorporate changes: (A) to the applicable rate schedules on file with the commission; (B) made by the commission in the exercise of its jurisdiction from time-to-time, and mutually agreed-upon by the contracting

[89] See, e.g., In re Hawaii Elec. Light Co., Inc., Docket No. 5525, Purchase Power Contract for Unscheduled Energy Made Available From a Qualifying Facility, dated March 24, 1986, between HELCO and Thermal Power Company, now known as PGV, Appendices D and I; In re Hawaii Elec. Light Co., Inc., Docket No. 6498, Firm Capacity Amendment to Purchase Power Contract Dated March 24, 1986, dated July 28, 1989, between HELCO and PGV, Appendix D; In re Hawaii Elec. Light Co., Docket No. 95-0074, Third Amendment to the Purchase Power Contract Dated March 24, 1986 as Amended by the Firm Capacity Amendment Dated July 28, 1989, dated March 7, 1995, between HELCO and PGV, Appendix D; In re Hawaii Elec. Light Co., Inc., Docket No. 96-0042, Performance Agreement and Fourth Amendment to the Purchase Power Contract Dated March 24, 1986 As Amended, dated February 12, 1996, between HELCO and PGV, Appendices D and F; In re Maui Elec. Co., Ltd., Docket No. 6616, Amended and Restated Power Purchase Agreement Between A & B Hawaii, Inc., Hawaiian Commercial & Sugar Company and MECO, dated November 30, 1989, Section III.B; In re Hawaiian Elec. Co., Inc., Docket No. 5514, Purchase Power Contract Between HECO and the City and County of Honolulu, dated March 10, 1986, Appendix D1; In re Hawaiian Elec. Co., Inc., Docket No. 6983, Firm Capacity Amendment to Purchase Power Contract Dated March 10, 1986, dated April 8, 1991, between HECO and the City and County of Honolulu, Appendix D; In re Hawaii Elec. Light Co., Inc., Docket No. 6956, Purchase Power Contract for As Available Energy From a Qualifying Facility, dated March 6, 1991, between HELCO and Wailuku River Hydro, Appendix D, and First Amendment to Purchase Power Contract for As Available Energy From a Qualifying Facility, dated August 12, 1991, between HELCO and Wailuku River Hydro; In re Hawaii Elec. Light Co., Inc., Docket No. 04-0016, Power Purchase Contract for As-Available Energy, dated December 30, 2003, between HELCO and Hawi Renewable Development, LLC, Appendix D; and In re Hawaii Elec. Light Co., Inc., Docket No. 04-0346, Restated and Amended Contract, dated October 13, 2004, between HELCO and Apollo Energy Corporation, Appendix D.

parties; (C) to the present avoided energy cost methodology; or (D) to the frequency in the quarterly avoided energy cost filings with the commission.[90] In addition, the payment rates agreed-upon between the independent power producer and electric utility (usually the minimum purchase rate, if any) may affect the producer's ability to qualify for and obtain third-party financing for the project.[91]

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[90]In re Hawaii Elec. Light Co., Inc., Docket No. 5525, Purchase Power Contract for Unscheduled Energy Made Available From a Qualifying Facility, dated March 24, 1986, between HELCO and PGV, Section 2(b); In re Maui Elec. Co., Ltd., Docket No. 6616, Power Purchase Agreement Between MECO and Alexander & Baldwin, Inc. dba Hawaiian Commercial & Sugar Company, dated July 31, 1980, Section X; Amended and Restated Power Purchase Agreement Between A & B Hawaii, Inc., Hawaiian Commercial & Sugar Company and MECO, dated November 30, 1989, Sections XII.A and XIII; and Decision and Order No. 10803, filed on October 11, 1990; In re Hawaii Elec. Light Co., Inc., Docket No. 6956, Purchase Power Contract for As Available Energy From a Qualifying Facility, dated March 6, 1991, between HELCO and Wailuku River Hydro, Sections 2(b) and 18(j); In re Hawaii Elec. Light Co., Inc., Docket No. 04-0016, Power Purchase Contract for As-Available Energy, dated December 30, 2003, between HELCO and Hawi Renewable Development, LLC, Section 2(b); In re Hawaii Elec. Light Co., Inc., Docket No. 04-0346, Restated and Amended Contract, dated October 13, 2004, between HELCO and Apollo Energy Corporation, Section 2(b), Appendix D, and HELCO's response to CA-IR-16; and In re Maui Elec. Co., Ltd., Docket No. 04-0365, Power Purchase Contract for As-Available Energy, dated December 3, 2004, between MECO and Kaheawa Wind Power, LLC, Section 2(b) and Appendix D.

[91]See, e.g., In re Hawaii Elec. Light Co., Ltd., Docket No. 6498, Confirmation of Purchase Power Contract and Agreement, dated June 29, 1990, between HELCO, Credit Suisse, and PGV; In re Hawaii Elec. Light Co., Inc., Docket No. 96-0042, Performance Agreement and Fourth Amendment to the Purchase Power Contract Dated March 24, 1986 As Amended, dated February 12, 1996, between HELCO and PGV, Exhibit C; and In re Hawaiian Elec. Co., Inc., Docket No. 04-0320, Lenders' Consent, dated December 8, 2004, between Kalaeloa Partners, L.P., and Ing Capital LLC; see also In re Hawaiian Elec. Co., Inc., Docket No. 5514, Decision and Order No. 8698, filed on March 31, 1986 (mutually agreed-upon minimum purchase rate was a critical factor in ensuring the economic viability of the H-Power Project); In re Hawaii Elec. Light Co., Inc., Docket No. 6956, Wailuku River

Under the circumstances, the commission will accept as reasonable, and thus, approve the Parties' agreement to apply their agreed-upon energy cost payment rates to the QFs with existing PPAs with the HECO Companies (as identified above); provided that such prospective application: (1) is consistent with the terms and conditions of the existing PPA between the electric utility and independent power producer; and (2) will not detrimentally affect the project financing contingencies and terms between the independent power producer and project lender.[92] This contingent approval, the commission makes clear, does not preclude the contracting parties from mutually agreeing to amend an existing PPA.

2.

Wailuku River Hydro

The Parties stipulate that, for QFs that utilize synchronous generators and are metered on the "high side" of the

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Hydro's letter, dated July 12, 1991, transmitting First Boston Corporation's letter, dated June 25, 1991 (critical nature of the minimum purchase rate for financing, i.e., obtaining a letter of credit to back the revenue bonds), and Decision and Order No. 11333, filed on October 28, 1991 (mutually agreed-upon minimum purchase rate for the Wailuku River Hydro Project was critical to the financing of the project); and In re Hawaiian Elec. Co., Inc., Docket No. 6983, HECO's letter, dated March 31, 1992, transmitting ABB Resource Recovery Systems' letter, dated February 27, 1992 (confirming the continual need for the minimum energy purchase rate to ensure the economic viability of the H-Power Project).

[92]With respect to the second proviso, the commission is cognizant of the Parties' agreement that the avoided energy costs determined in accordance with the Updated Stipulation will not change or otherwise affect the minimum purchase rate or rates applicable to any existing PPA. See Parties' Updated Stipulation, at 14.

step-up transformer, a specific allowance will be made for transformer losses, as a "gross-up" to the generation meter reading. The stipulated adjustment factor for HELCO QFs is 0.50 percent.

MKPC/HARC, on behalf of Wailuku River Hydro, seeks retroactive compensation for avoided transformer losses (0.5% adjustment factor), with interest, from the filing date of the Initial Stipulation. By way of background, MKPC/HARC states:

1. Section 8 of the power purchase agreement, relating to metering, states:

> Metering. The Company shall supply, own and maintain all necessary meters and associated equipment utilized for billing and energy purchase. The meters shall be tested and read in accordance with the Rules of the Company and [Commission] rules as either may be amended from time to time. The Seller shall supply, at no expense to the Company, a suitable location for meters and associated equipment used for billing and energy purchase.

Purchase Power Contract for As Available Energy from a Qualifying Facility, dated March 6, 1991, between HELCO and Wailuku River Hydro, Section 8, at 4.

2. The power purchase agreement is silent on the exact location of the revenue meter. During 1992, HELCO and Wailuku River Hydro discussed the meter location issue.[93]

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[93]Statement of Position on behalf of Wailuku River Hydro, at 2-3. According to MKPC/HARC, Wailuku River Hydro informed the commission of the interconnection and meter location issues in In re Hawaii Elec. Light Co., Inc., Docket 7149, HELCO's application to commit funds to construct and install facilities to interconnect Wailuku River Hydro's hydroelectric facility with HELCO's grid.

On October 1, 1992, the commission approved HELCO's application to commit funds to interconnect Wailuku River Hydro's

3. "In prior submissions to HELCO, Wailuku had located the revenue meter on the low voltage side of the step-up transformer. Wailuku believed this to be consistent with past practice and the methodology utilized to calculate avoided cost."[94]

4. HELCO requested that the meter be located at the high voltage side of the transformer. "The consequence of the HELCO proposed meter placement was that the meter would 'under-read' [as much as one percent] the energy generated by Wailuku, by introducing the transformer loss as a deduction to the Wailuku generation read on the meter."[95]

5. On May 11, 1992, the commission opened Docket No. 7310. The commission denied Wailuku River Hydro's motion to intervene, and instead, its interests were handled by MKPC/HARC.

6. "By informal agreement Wailuku agreed to proceed with the installation of [the] meter on the high side of the transformer, with the issue of adjustment and the amount thereof, to be resolved in [Docket No. 7310]. Construction of the project commenced in order to meet the PPA on-line date of

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hydroelectric facility with HELCO's grid. Docket No. 7149, Decision and Order No. 11888, filed on October 1, 1992. Subsequently, on February 17, 1995, the commission approved HELCO's motion to rescind Decision and Order No. 11888, based on Wailuku River Hydro's agreement to assume full responsibility for the construction of the interconnection facilities. Docket No. 7149, Order No. 13776, filed on February 17, 1995.

[94]Statement of Position on behalf of Wailuku River Hydro, at 2.

[95]Statement of Position on behalf of Wailuku River Hydro, at 2-3.

June 30, 1993."[96] The hydroelectric facility was completed in June 1993, on-schedule.

7. Following the execution of the Initial Stipulation, Wailuku River Hydro on several occasions requested payment for the amount of power generated, applying the 0.5 percent meter adjustment factor. HELCO denied the request on each occasion, stating that the Initial Stipulation had yet to be approved by the commission.

MKPC/HARC, on behalf of Wailuku River Hydro, seeks compensation from HELCO for avoided transformer line losses (0.5% adjustment factor), with interest, retroactively back to the filing date of the Initial Stipulation.[97] In support of this request for retroactive compensation, MKPC/HARC contends:

1. Wailuku River Hydro: (A) is not at fault for the passage of time in the commission's approval of the stipulation; (B) did not object to the requests for extensions of time to file updates to the Initial Stipulation; (C) did not file separate complaint proceedings; and (D) has been cognizant of the commission's and each of the party's time.

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[96]Statement of Position on behalf of Wailuku River Hydro, at 4.

[97]Parties' Updated Stipulation, at 12-13; and Statement of Position on behalf of Wailuku River Hydro.

As stated by MKPC/HARC, "the Commission should order that HELCO pay Wailuku River [Hydro] a transformer adjustment of 0.5% for all of the power it has delivered, with interest to be provided at a rate set by the Commission. Further, that HELCO should be allowed to recover the cost so paid in its fuel adjustment clause in accordance with the PPA, as approved by the Commission." Statement of Position on behalf of Wailuku River Hydro, at 6.

2. The consumer will not be harmed by retroactively compensating Wailuku River Hydro for avoided step-up transformer losses.

3. Given the monetary amount in dispute, Wailuku River Hydro has relied on the fundamental fairness of the commission, and it should not be penalized for the long length of this proceeding.[98]

Respondents, by contrast, oppose Wailuku River Hydro's request for retroactive treatment of compensation for avoided step-up transformer line losses,[99] asserting that:

1. Wailuku River Hydro has been properly paid for energy delivered to HELCO, pursuant to the PPA.[100] The PPA does not specify a transformer loss adder, and there is no transmission loss adder to the filed avoided energy costs determined using the proxy method. Thus, HELCO has duly paid the rates specified under the PPA (including the minimum purchase rates, when applicable), and there is no basis for Wailuku River Hydro to now claim that it should have been paid more than it was entitled to under the PPA.

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[98]MKPC/HARC estimates that: (1) on the filing date of the Initial Stipulation, the amount in controversy was $6,398; and (2) as of October 31, 2006, the amount increased to $170,575, without interest.

[99]Parties' Updated Stipulation, at 13; and Respondents' Reply.

[100]<u>See</u> Respondents' Reply, at 4-5.

2. There is no basis for applying the Initial Stipulation or the Updated Stipulation, prior to the commission's approval of the stipulation.[101] The Updated Stipulation: (A) is not effective without the commission's approval; and (B) does not state that it will be applied retroactively if (and once) approved by the commission. Instead, the Updated Stipulation, if (and once) approved, must be applied prospectively.

3. There is no basis for singling out one of the terms of the Initial Stipulation, or the Updated Stipulation, and applying that term retroactively to the filing date of the Initial Stipulation, while ignoring the other terms of the stipulation.[102]

4. In Docket No. 6956, Wailuku River Hydro received special treatment with respect to the minimum purchase rates included in the PPA, and it is not in a position legally or factually to complain about not receiving a transmission loss adder.[103] Specifically, in Docket No. 6956:

> HELCO agreed to, and the Commission approved minimum purchase rates based on the avoided cost payment rates for the first quarter of 1991 [(the execution date of the PPA)], although the amended PPA was not approved [by the commission] until the fourth quarter of 1991, at which time avoided cost payment rates had declined from the peak reached in the first quarter during the Gulf War. As a result, Wailuku River Hydro has received substantially more compensation than it would have been paid had the minimum purchase rates been set at the rates in effect when its amended PPA was approved. One of the reasons that HELCO agreed to the minimum purchase rates was

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[101] See Respondents' Reply, at 5.

[102] See Respondents' Reply, at 5-6.

[103] See Respondents' Reply, at 6-10.

> that Wailuku River Hydro agreed to a standard as-available energy contract. <u>Such a contract called for the payment of filed avoided energy rates (subject to the minimum purchase rates) for kwh metered on the high side of the step-up transformer</u>. Wailuku River Hydro has accepted the higher minimum purchase rates, but now wants to retroactively redo the deal with respect to the metering point.

Respondents' Reply, at 8 (footnotes and text therein omitted) (emphasis added).

The commission agrees with Respondents. HRS § 1-3 states:

> **Laws not retrospective.** No law has any retrospective operation, unless otherwise expressed or obviously intended.

HRS § 1-3.

The commission, in commencing this investigation, did not intend for its decisions to have any retroactive effect. In this regard, as noted by Respondents, the stipulations contain no provision for retroactivity. Moreover, the stipulations were submitted by the Parties to the commission for its review and consideration, with the commission having the authority to approve or reject, in whole or in part, the stipulations. Any resulting compromises, methods, or procedures incorporated in the stipulations, will not take effect unless approved by the commission. The agreements, procedures, and methods set forth in the Updated Stipulation, once approved by the commission, will apply prospectively in nature, and not retroactively.

Accordingly, the commission denies the request of MKPC/HARC, made on behalf of Wailuku River Hydro.

3. Environmental Externalities

The HECO Companies and the DOD note that the definitions of avoided costs and avoided energy costs in HAR § 6-74-1 do not refer to environmental externalities.[104]

MKPC/HARC describes environmental externalities in the following manner:[105]

> Environmental regulations set allowable limits for pollution by utilities and other industries. These limits are becoming ever stricter. The costs associated with meeting these pollution limits for utilities are "internalized" and are reflected in the cost of electrical production. "Externalities" are those costs which occur outside of the achievement of government pollution requirements. These costs are borne by ratepayers as a whole. Under current regulations, those who reduce those costs are uncompensated for the external benefits conferred upon society. Monetizing externalities for electrical generation would assist the ratepayers of Hawaii in three ways: 1) the external costs of older utility plants, not meeting current pollution standards could be reduced; 2) current resource decisions

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[104]HAR § 6-74-1 states in relevant part:

> "Avoided costs" means the incremental or additional costs to an electric utility of electric energy or firm capacity or both which costs the utility would avoid by purchase from the qualifying facility.
>
> "Avoided energy costs" means the energy costs consisting of cost of fuel and generation operating and maintenance costs as a minimum with fuel inventory, working cash, line loss costs considered when presented in a specific proposal from a qualifying facility to the electric utility.

HAR § 6-74-1.

[105]See MKCP/HARC's Statement of Position, filed on March 2, 1994, Section I.A, at 10.

> could take into account these costs in resource acquisition; 3) [c]ost risks associated with future environmental pollution abatement costs could be minimized.

MKPC/HARC's Statement of Position, at 10 (emphasis in original) (footnote and text therein omitted).

The HECO Companies define environmental externalities as:[106]

> . . . externalities that have to do with the environment, such as costs to society from air or water pollution. Generally, environmental externalities fall under the categories of air, land and water. Some of the environmental costs to society from electricity production are already included into the general pricing system and can not be considered externalities. For example, costs incurred to bring power plants into compliance with environmental laws and regulations are not environmental externalities because the ratepayer is paying for these costs in the price of electricity. These costs are said to have been "internalized." HECO T-2 at 25.

HECO Companies' Statement of Position, at 33.

MKPC/HARC contends that the commission should include environmental externalities in calculating avoided costs, asserting that:[107]

1. Environmental externalities are real, should and can be monetized in Hawaii, and constitute a component of the utility's full avoided costs.

2. Adders must be used in both resource selection and acquisition. In the event adders are used in only the resource planning process, an "unlevel" playing field will result.

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[106] See HECO Companies' Statement of Position, filed on March 2, 1994, Section V.B, at 32-34.

[107] See MKPC/HARC's Statement of Position, filed on March 2, 1994 ("Statement of Position"), Section I, at 10-20.

3. In Docket No. 6742, Zond Pacific's witness presented detailed testimony on the quantification of externalities from a Hawaii-specific point of view.[108]

MKPC/HARC recommends that the commission include as a placeholder an externality value of 5 mills per kWh in the avoided energy cost rate payable for non-fossil fuel projects (solar, wind, and hydro projects) in operation after July 15, 1989 (including Wailuku River Hydro),[109] until such value is revised as part of the IRP process.[110] The 5 mills per kWh figure represents approximately one-fifth of the total externality estimate for new combined cycle generation and one-third of the estimate for air pollutants.[111]

Conversely, Respondents jointly assert that "no externalities adder should be included in the calculation of the subject avoided costs."[112]

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[108]Zond Pacific's witness in Docket No. 6742 and MKPC's witness in Docket No. 7310 is the same person. Essentially, MKPC/HARC proposes to incorporate by reference in Docket No. 7310, the testimony presented by Zond Pacific in Docket No. 6742.

[109]According to MKPC/HARC, July 15, 1989 represents the filing date of HELCO's application in Docket No. 6432. See MKPC/HARC's Statement of Position, at 9 and 16.

[110]See MKPC/HARC's Rebuttal Testimony, at 51 and 56; MKPC/HARC's Statement of Position, at 15-20; and Parties' Updated Stipulation, at 15.

[111]See MKPC/HARC's Rebuttal Testimony, at 51; and MKPC/HARC's Statement of Position, at 15.

[112]Parties' Updated Stipulation, at 16.

The HECO Companies contend:[113]

1. There is no basis for requiring electric utilities to pay an externalities adder for as-available energy rates.

2. External costs, by definition, are not part of an electric utility's avoided costs. Accordingly, if QFs are paid rates equal to the utility's avoided costs, plus external costs, the payment rates will be higher than the utility's avoided costs. Thus, the payment of an externalities adder will not be just and reasonable to the consumer.

3. Any externalities adder will have to be limited to non-fossil fuel producers that can be demonstrated to have net externality benefits, and such producers are already paid more than avoided costs through the provision of minimum rates.

4. The requirement of an externalities adder will be premature pending determination of the weight to be given externalities in the resource selection process. The appropriate forum to make this determination is in the integrated resource planning process.[114]

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[113]<u>See</u> HECO Companies' Statement of Position, filed on March 2, 1994 ("Statement of Position"), Section V, at 30-44.

[114]As noted by the HECO Companies:

> It would be inappropriate at this time to include a value for externalities in computing avoided costs for as-available energy producers. An IRP process is a better forum for considering externalities. The consideration of externalities in an IRP process differs from actually paying as-available energy producers for externality avoidance. The latter causes ratepayers to directly pay for externality values, the quantification of which is speculative. The former (IRP process) only influences resource selection. Ratepayers should only pay for incurred, measurable and verifiable costs.

5. Any externalities adder will be speculative pending determination of the appropriate method or methods to be used in quantifying and monetizing externalities, and no reliable, probative, and substantial evidence has been presented in this proceeding regarding the appropriate value of an externalities adder, or of the net externalities "benefits" of various non-fossil fuel producers. In effect, externality costs cannot be accurately quantified or monetized.

Similarly, the DOD contends that QFs and other power suppliers are not entitled to compensation for environmental externalities, reasoning that:[115]

> Estimates of environmental externalities are not well developed currently, and are speculative at best. HSPA/MKPC did not provide sufficient reasons for the Commission to adopt quantified externality values in this proceeding. Accordingly, avoided environmental externalities should not be included in avoided energy cost rates paid to QFs.
>
> . . . .
>
> HSPA/MKPC asserted that the Commission has developed a significant amount of data in the IRP process and does not need to repeat that process here and develop values from scratch in this case. Environmental externality values developed for the IPR process are not monies paid from any ratepayers' pockets. Instead, they are simply values used to influence the selection of resources. No "windfall profits" to suppliers are granted by such use of environmental costs in the IRP process. When actual payments are made from the ratepayers to energy producers, the [utility] and its regulators have a responsibility to ensure that payments are just and reasonable. Externalities estimates simply do not meet that test.

HECO Companies' Statement of Position, filed on March 2, 1994 ("Statement of Position"), at 43-44 and 46 (citations to testimony omitted).

[115]See Position Statement of DOD, filed on March 2, 1994 ("Statement of Position"), Section II, at 4-5.

1. There is no reliable quantification of environmental externalities.

2. Environmental externalities are not an avoided cost. Externalities do not fit within the definition of avoided costs under HAR § 6-74-1, that may be paid to QFs. Specifically, externalities are not costs that a utility avoids by purchased power from one source as opposed to another.

3. There is no agreement on what environmental externalities are, and how they should be considered in the utility decision-making process.

4. There is no evidence in the docket record that Hawaii-specific values have been developed for any externality. Consideration of externalities in the context of power purchased from QFs is clearly premature and inappropriate.

The Consumer Advocate asserts that: (1) no externalities variable should be included in the calculation of the subject avoided costs; (2) the consideration of externalities is an issue that is appropriately addressed in the HECO Companies' IRP proceedings; and (3) it reserves the right to present its position on externalities with respect to integrated resource planning in the HECO Companies' IRP planning process and Advisory Group meetings.[116]

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[116]The Consumer Advocate, in support of its position: (1) refers to FERC's rulings on avoided costs and externalities adders; and (2) the HECO Companies' plan to consider renewable set-asides in conjunction with the competitive bidding/IRP processes set forth in In re Public Util. Comm'n, Docket No. 03-0372. See Parties' Updated Stipulation, at 15-16.

Here, the issue facing the commission is whether environmental externalities should be taken into account by the HECO Companies in determining their respective avoided energy costs. In effect, whether the definition of avoided energy costs should include environmental externalities.[117]

In In re Southern California Edison Co. and San Diego Gas & Elec. Co., Dockets No. EL95-16-000 and No. EL95-19-000 (consolidated), FERC provided the following guidance to the states:

> 3. Guidance
>
> . . . .
>
> Further, in our February 23[, 1995] decision, we stated that "our decision today does not, for example, preclude the possibility that, in setting an avoided cost rate, a state may account for environmental costs of all fuel sources included in an all source determination of avoided cost." 70 FERC at 61,676. This means that environmental costs, if they are real costs that would be incurred by utilities, may be accounted for in a determination of avoided cost rates. Under section 210(b) of PURPA, "no rule . . . shall provide for a rate which exceeds the incremental cost to the electric utility of alternative electric energy." (emphasis added.) Thus, in setting avoided cost rates, a state may only account for costs which actually would be incurred by utilities. A state may, through state action, influence what costs are incurred by the utility. Thus, accounting for environmental costs may be part of a state's approach to encouraging renewable generation. For example, a state may impose a tax or other charge on all generation produced by a particular fuel, and thus increase the costs which would be incurred by utilities in

[117] At the same time, MKPC/HARC proposes to limit the payment of avoided energy costs for environmental externalities to non-fossil fuel projects (solar, wind, and hydro projects) in operation after July 15, 1989 (including Wailuku River Hydro), until such value is revised as part of the IRP process. See MKPC/HARC's Statement of Position, at 15-20; and Parties' Updated Stipulation, at 15.

> building and operating plants that use that fuel. Conversely, a state may also subsidize certain types of generation, for instance wind, or other renewables, through, e.g., tax credits.
>
> A state, however, may not set avoided cost rates or otherwise adjust the bids of potential suppliers by imposing environmental adders or subtractors that are not based on real costs that would be incurred by utilities. Such practices would result in rates which exceed the incremental cost to the electric utility and are prohibited by PURPA.

Order on Requests for Reconsideration, issued on June 2, 1995, at 12 (emphasis in original); see also Order on Petitions Issued for Enforcement Action Pursuant to Sections 210(h) of PURPA, issued on February 23, 1995.[118]

Thus, FERC instructs that: (1) a state, in setting avoided cost rates, may only account for costs that will actually be incurred by the electric utility; and (2) environmental costs, if they are real costs that will be incurred by the electric utility, may be accounted for in the determination of avoided cost rates. Conversely, a state may not set avoided cost rates by imposing environmental adders that are not based on real costs that will be incurred by the electric utility.

MKPC/HARC relies on the environmental and security premium proposed by Zond Pacific in Docket No. 6742, wherein Zond Pacific's witness calculated and quantified the value of this premium as between 2.47 cents/kWh to 5.15 cents/kWh (1990$).[119] The commission, in Docket No. 6742, did not

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[118]The Initial Stipulation pre-dates the FERC Orders. The Updated Stipulation, by contrast, incorporates by reference the FERC Orders. See Parties' Updated Stipulation, at 15-16.

affirmatively accept or reject Zond Pacific's proposal; in particular, the methodology and assumptions utilized in quantifying and monetizing the environmental and security externalities identified by Zond Pacific.[120] As instructed by FERC, environmental costs may only be accounted for in the determination of avoided cost rates if they are real costs that will actually be incurred by the utility. While Zond Pacific's witness quantified and monetized the environmental and security externalities that were identified by Zond Pacific, its witness did not bridge the gap and explain how the HECO Companies will avoid actual and real costs by using renewable energy instead of

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[119]The environmental and security premium proposed by Zond Pacific (and opposed by MECO and the Consumer Advocate) consisted of:

1. An environmental component, based on Zond Pacific's estimate of the value to society of: (A) displacing certain residual air pollution (i.e., air pollution remaining after compliance with environmental laws and regulations) from MECO's oil-fired generating units with wind generated energy; and (B) reducing oil spills resulting from the transportation of fuel oil; and

2. A fuel diversity, energy security and energy price stabilization component, based on Zond Pacific's estimate of the value to society of: (A) reducing Hawaii energy shortage in time of embargo or short supply; (B) reducing the United States' reliance on oil; and (C) stabilizing energy prices.

See Docket No. 6742, Direct Testimony of William B. Marcus, at 3-22; and HECO Companies' Statement of Position, at 44-45.

[120]Instead, the commission found that, in light of Docket No. 7310 and Docket No. 7258 (MECO's IRP-1 docket), Zond Pacific's "proposal to negotiate a power purchase contract that includes an environmental and security premium pricing structure appears to be premature." Docket No. 6742, Decision and Order No. 12118, at 7-8.

fossil fuel energy. Moreover, in the commission's view, environmental externalities are specific to the location and type of facility being avoided.

The commission finds that, based on the docket record herein and consistent with the guidance provided by FERC, the commission may not set avoided cost rates by imposing environmental adders that are not based on real costs that will be incurred by the electric utility. This ruling by no means affects the commission's review of externalities in the IRP process, as proposed by Respondents.

D.

Stipulated Issue No. 5

MKPC/HARC and Respondents have not reached agreement on Stipulated Issue No. 5: What are the HECO Companies' avoided capacity costs, if any, resulting from their purchase of energy on an as-available basis from qualifying facilities.

In general, MKPC/HARC asserts that as-available producers of energy are entitled to capacity payments. In support thereto, MKPC/HARC contends:[121]

1. The commission should take the broadest possible view and encourage alternative energy technologies to the maximum extent practicable.

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[121]See MKPC/HARC's Statement of Position, Section II, at 20-44.

2. Factors for consideration established by FERC, and codified by the commission in HAR § 6-74-23, include "the availability of capacity from the qualifying facility during peak periods, the reliability of the facility, the ability to bring generation on in small increments thus avoiding 'lumpiness' in the utility system and the length of time in which the facility has guaranteed that it will supply energy or capacity to the utility."[122]

3. Furthermore, consistent with FERC policy:

> . . . In some instances, the small amounts of capacity provided from qualifying facilities, taken individually, might not enable a purchasing utility to defer or avoid scheduled capacity additions. The aggregate capability of such purchases, may, however, be sufficient to permit the deferral or avoidance of a capacity addition. Moreover, while an individual qualifying facility may not provide the equivalent of firm power to the utility, the diversity of these facilities may collectively comprise the equivalent of capacity.

MKPC/HARC's Statement of Position, at 21 (quoting 45 Fed. Reg. 12227).

4. The California Public Utilities Commission authorized capacity payments for as-available energy as part of the standard offer for QFs below 100 kW in size, based on the electric utilities' short-run marginal costs and the aggregate capacity value concept recognized by FERC.

5. The empirical data desired by the HECO Companies in Docket No. 4569, Decision and Order No. 8298, is presently available, and the "actuality" standard set forth by the commission therein has been met.

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[122]MKPC/HARC's Statement of Position, at 21 (citing 18 C.F.R. § 292.304(e)).

6. The empirical data analyzed by MKPC/HARC shows that: (A) HELCO's two hydroelectric facilities continue to provide reliable power; (B) during a thirteen-year period, at the time of HELCO's system peak, HELCO's hydroelectric plants provided energy and capacity to HELCO's system one-hundred percent of the time, and the as-available hydroelectric producers (including Wailuku River Hydro) carried nearly ten percent of HELCO's system peak; and (C) during a six-year period, at the time of HELCO's system peak, HELCO was receiving capacity and energy from wind producers. Thus, based on the empirical data, as-available producers of energy are providing capacity to HELCO's system, without compensation.

7. As-available producers consistently supplied energy and capacity to HELCO during times of system emergency, thereby lessening capacity needs, increasing system reliability, and forestalling or lessening rolling blackouts.

8. Hawaii's electric utilities have facilitated reliability through the installation of combustion turbines, and the reliability value of capacity for as-available producers is the value of a combustion turbine. Thus, as-available producers should be credited with one-hundred percent of the value of a combustion turbine, adjusted for the capacity factor of the facility. This proposal allows the as-available producer to recoup the actual value of the peaking turbine, as adjusted (or discounted) by its actual availability.

9. The HECO Companies have presented no empirical data showing that as-available producers do not provide capacity value.

Based on the foregoing, "MKPC/HARC's position with respect to capacity payments is that as-available producers: (i) who commit to contracts of five-years or more are reliable producers, (ii) in the aggregate provide capacity value; and (iii) at a minimum extend the life of existing utility assets, defer overhauls and defer the installation of new capacity."[123]

Respondents counter that no capacity payments for as-available energy producers should be included in the calculation of avoided energy costs.[124]

The HECO Companies contend:[125]

1. There is no obligation for the supplier to deliver power and energy when it is needed by the HECO Companies. Hence, in the short-term, the as-available energy producer cannot be counted on to provide capacity. In addition, the as-available energy producer has no continuing obligation to maintain production levels. Even if the as-available producer operates at

[123]Parties' Updated Stipulation, at 17.

[124]From the outset, the HECO Companies and DOD's position was that the electric utilities cannot avoid capacity additions as a result of as-available energy purchases, and thus, no capacity payment to as-available energy producers is warranted. The Consumer Advocate initially disagreed, but based on the commission's subsequent ruling in In re Apollo Energy Corp., Docket No. 00-0135, Decision and Order No. 18568, filed on May 30, 2001, the Consumer Advocate has changed its position. The Consumer Advocate now believes that no capacity payments for as-available energy producers should be included in the calculation of avoided energy costs.

[125]See HECO Companies' Statement of Position, Section IV, at 18-30.

relatively constant levels during any single year, the HECO Companies are unable to defer construction of needed capacity, which requires at least several years of lead time.

2. Because the HECO Companies cannot avoid the need for additional capacity through the purchase of as-available energy, such energy has no capacity planning value, and does not result in avoided capacity costs.

3. The reliability value of as-available energy purchases is speculative. Specifically, while the purchase of as-available energy may result in the enhanced ability to meet customer load, such value cannot be forecasted with a reasonable degree of accuracy.

4. MKPC/HARC's proposal of a capacity credit equal to one-hundred percent of the cost of a combustion turbine per on-peak kWh, for kWhs actually delivered on-peak, is problematic and should not be adopted. Specifically, the proposal fails to consider:

A. The unique supply availability of various as-available supplies;

B. The specific load and capacity situation of the utility and whether the utility can in fact avoid capacity costs as a result of an as-available energy supply;

C. The contractual commitments made by as-available suppliers and the implications of these commitments upon the HECO Companies' ability to avoid capacity costs; and

D. That if avoided capacity costs are reflected in avoided energy costs, avoided energy costs will need to be re-computed to reflect the impact of deferred capacity.[126] This will lower avoided energy costs.

5. If the HECO Companies were required to make payments to non-firm producers based on the cost of a combustion turbine, and were also required to add a combustion turbine to its system to back-up non-firm producers pursuant to the utilities' capacity addition criteria, ratepayers will end up paying twice for the combustion turbine.

6. In addition, if the utility relies on as-available energy resources, and installs combustion turbines instead of baseload units, it ends up paying more for the energy than if it had installed the more efficient baseload units. Thus, there is no basis to pay a capacity cost premium for an as-available energy contract that does not actually allow the utility to defer or displace its own capacity additions.

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[126]The HECO Companies further note that in deciding whether capacity payments are appropriate, it will also be necessary to consider:

1. The degree to which a specified quantity of non-firm or as-available energy will be guaranteed for any year;

2. The appropriate penalties for non-performance;

3. The term of the commitment to provide non-firm energy (i.e., one year, five years, twenty years, or more); and

4. The load and capacity situation of the utility, considering the utility's ability to defer construction of required generation, which will affect the need for and value of any additional capacity.

Similarly, the DOD asserts:[127]

1. Electric utilities do not avoid any capacity costs when energy is purchased on an as-available basis from QFs or other independent power producers.

2. As-available producers have no legally enforceable obligation to deliver energy at times when it may be needed by the utility, either in the short-run or long-run. Thus, such energy supplied on an as-available basis has no capacity value and cannot be counted upon by the utility as a substitute for utility constructed capacity or for capacity acquired through a firm power purchase contract. In short, the utility is unable to avoid the installation of capacity resulting from the purchase of energy from as-available suppliers.

3. The data described by MKPC/HARC only shows that the presence of additional capacity on a utility's system during a particular period will contribute to increased reliability for that period. What is not addressed is the lack of assurance that capacity that is available today will be available at any time in the future. The HECO Companies have not altered their resource mix as a result of purchases from as-available energy generation.

The commission agrees with Respondents. In Wind Ass'n of Hawaii, Inc. v. Hawaiian Elec. Co., Inc., Docket No. 4569, Decision and Order No. 8298, the commission held:

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[127] See DOD's Statement of Position, Section I, at 1-3.

> The remaining issue involves the computation and inclusion of capacity costs to be paid to producers under 100 kws . . . .
>
> . . . .
>
> The record is clear as it relates to Schedule Q that there are no avoidable capacity costs within the near future. We do not believe that the term "avoided costs" involves an indefinite period of time and that the near term period should be used. The Utilities maintained that since there is no capacity additions planned within the next several years there is really no capacity cost that the Utilities would avoid. Therefore no capacity value should be included in the calculations of the avoided cost in Schedule "Q".
>
> The Intervenors acknowledged that individually Schedule "Q" producers may not have significant capacity value, but in the aggregate they certainly can add capacity value to the system. The Utilities disagreed stating that "while we are still gaining experience, to date we have no data to demonstrate that collective value of all the Schedule Q producers lower the capacity requirements." We note also that, . . . there are only four operating windmills each on Oahu and Maui and 14 on Kohala/Waimea on the Island of Hawaii. The Intervenors [have] not shown in actuality that there are sufficient number of windmills which are sufficiently dispersed to provided added capacity value in [the] aggregate to lessen the Utilities' need for reliable capacity. We conclude that capacity payments to Schedule Q producers of under 100 kilowatts are not warranted and would not adversely affect the long term goal of encouraging the development of alternate energy sources on a commercial basis. We should emphasize that such conclusion is not applicable to producers in the over 100 kilowatts category [that] intend to engage in the commercial development of alternate sources of energy.

Wind Ass'n of Hawaii, Inc. v. Hawaiian Elec. Co., Inc., Docket No. 4569, Decision and Order No. 8298, at 13-14 (emphasis in original).

More recently, in In re Apollo Energy Corp., Docket No. 00-0135, the commission adjudicated certain issues with respect to the inability of HELCO and an independent power producer of wind energy, Apollo Energy Corporation ("Apollo"), to reach agreement on a new or amended power purchase agreement. One of the disputed issues addressed by the commission was whether the proposed new or amended power purchase agreement should include a provision for capacity payments to Apollo.[128]

The commission, in denying Apollo's request for capacity payments from HELCO, reasoned:

> The commission does not believe that capacity payments for Apollo are warranted. Rather, HELCO, under its generation capacity planning criteria, is unable to avoid or defer the construction of its own generation additions as a result of the intermittent energy generated by a wind farm such as Kamaoa. Nor is HELCO able to avoid the fixed operations and maintenance costs associated with its own generation.
>
> The wind resource used by Apollo to generate energy is as-available. The generation of energy by wind farms such as Apollo is ultimately dependent upon the availability and strength of this resource. Apollo, the commission finds, is not under a continual obligation to supply power to HELCO upon demand.

In re Apollo Energy Corp., Docket No. 00-0135, Decision and Order No. 18568, filed on May 30, 2001, at 4.[129]

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[128]Apollo was the operator of the Kamaoa wind farm located at South Point on the island of Hawaii. Its wind farm was designated a qualifying facility by FERC.

[129]Decision and Order No. 18568: (1) was issued by the commission subsequent to the filing of the position statements and Initial Stipulation in Docket No. 7310; and (2) is referenced by the Consumer Advocate in the Updated Stipulation.

The commission finds no discernible basis for deviating from its pertinent ruling in Decision and Order No. 18568. Accordingly, the commission: (1) reaffirms its holding and rationale in Decision and Order No. 18568; and (2) reiterates its position that as-available producers of energy are not entitled to capacity payments.

E.

Summary of Findings and Conclusions

The commission's findings and conclusions are summarized as follows:

1. The agreements, methods, and procedures stipulated to by the Parties, as reflected in the Updated Stipulation, are accepted as reasonable, and thus, are approved; provided that the Parties' agreement to prospectively apply their agreed-upon energy cost payment rates to the QFs with existing PPAs, as identified on pages 13 - 14 of the Updated Stipulation: (A) is consistent with the terms and conditions of the existing PPA between the electric utility and independent power producer; and (B) will not detrimentally affect the project financing contingencies and terms between the independent power producer and project lender. This conditional approval does not preclude the contracting parties from mutually agreeing to amend an existing PPA.

2. Written requests submitted to the commission to resolve disputed matters, as reflected in the procedures set forth in the Parties' Exhibit A, shall comply with the commission's procedures governing the filing of complaints, HAR chapter 6-61, subchapter 5.

3. The request of MKPC/HARC, made on behalf of Wailuku River Hydro, seeking retroactive compensation for avoided transformer line losses (0.5% adjustment factor), with interest, from the filing date of the Initial Stipulation, is denied.

4. Based on the docket record herein and consistent with the guidance provided by FERC, the commission may not set avoided cost rates by imposing environmental adders that are not based on real costs that will be incurred by the electric utility.

5. The commission reaffirms its position in Docket No. 00-0135, Decision and Order No. 18568, that as-available producers of energy are not entitled to capacity payments.

6. Consistent with Exhibit B, Paragraph No. 4, of the Parties' Updated Stipulation:

> The new methodology will be implemented 4 months after the issuance of the D&O approving this stipulation, including 2 months for the execution of the production simulations, 1 month for review by the parties, and 1 month for any additional simulations. The initial updated avoided energy cost rates and Schedule Q rates would go into effect on the 1st day of the month following this 4 month period. The schedule for ensuing updates is addressed in [Paragraph No. 5 of Exhibit B.]

Parties' Updated Stipulation, Exhibit B, at 1 - 2.

III.

Orders

THE COMMISSION ORDERS:

1. MKPC/HARC's request, filed on November 30, 2006, for leave to amend or supplement their Statement of Position, following the issuance of this Decision and Order, is denied.

2. The agreements, methods, and procedures agreed-upon by the Parties, as reflected in the Updated Stipulation, are approved; provided that the Parties' agreement to prospectively apply their agreed-upon energy cost payment rates to the QFs with existing PPAs, as identified on pages 13 - 14 of the Updated Stipulation: (A) is consistent with the terms and conditions of the existing PPA between the electric utility and independent power producer; and (B) will not detrimentally affect the project financing contingencies and terms between the independent power producer and project lender. This conditional approval does not preclude the contracting parties from mutually agreeing to amend an existing PPA.

3. Written requests submitted to the commission to resolve disputed matters, as reflected in the procedures set forth in the Parties' Exhibit A, shall comply with the commission's procedures governing the filing of complaints, HAR chapter 6-61, subchapter 5.

4. The request of MKPC/HARC, made on behalf of Wailuku River Hydro, seeking retroactive compensation for avoided transformer line losses (0.5% adjustment factor), with interest, from the filing date of the Initial Stipulation, is denied.

5. Consistent with Exhibit B, Paragraph No. 4, of the Parties' Updated Stipulation, the new methodology will be implemented four months following the issuance of this Decision and Order, including two months for the execution of the production simulations, one month for review by the Parties, and one month for any additional simulations. The initial updated avoided energy cost rates and Schedule Q rates will go into effect on the 1st day of the month following this four-month period.

DONE at Honolulu, Hawaii: MAR 11 2008.

PUBLIC UTILITIES COMMISSION
OF THE STATE OF HAWAII

By [signature]
Carlito P. Caliboso, Chairman

By (EXCUSED)
John E. Cole, Commissioner

By [signature]
Leslie H. Kondo, Commissioner

APPROVED AS TO FORM:

[signature]
Michael Azama
Commission Counsel

7310.laa

PRODUCTION COSTING MODEL

1. HECO, HELCO and MECO (jointly referred to herein as the HECO utilities) will use a PC-based, commercially available, production costing model. An ad hoc advisory group was formed to assist each of the HECO utilities in its choice of an appropriate model (see below).

   Each of the HECO utilities will provide a copy of the calibrated input data set, used to determine the annually updated short term avoided fuel cost, by email to the parties and to entities with power purchase agreements for facilities with a nameplate capacity of greater than one megawatt that incorporate filed avoided energy cost pricing incorporating such avoided fuel cost determined thereby ("the recipients")[1], at the HECO utilities' expense. For information deemed confidential and proprietary by the HECO utilities, the HECO utilities shall provide such information to the parties and recipients upon their execution of a confidentiality agreement, or pursuant to a protective order entered into in this proceeding

   In the event a party or recipient raises an issue with respect to the production costing model and/or modeling assumptions, the HECO utilities and the party or recipient agree to informally work together to attempt to resolve such issue. If the HECO utilities and the party or recipient are unable to resolve an issue to their mutual satisfaction, the party or recipient with the unresolved issue may request that the Commission resolve the matter by filing a written request with the Commission, within 30 days of the receipt of such information, attaching the relevant information, and serving the request on the other parties to the proceeding. The other parties shall have the opportunity, at their discretion, to respond to the party or recipient with the unresolved issues written request with the Commission by filing a written response with the Commission, and serving the response on the other parties to the proceeding, and the recipient, if applicable.

2. The HECO utilities have agreed to run a reasonable number of scenarios at the request of other parties or recipients, for the purpose of determining short term avoided fuel costs, for a reasonable charge (based on HECO's cost to do such runs). HECO estimates the charge be about $55/hour. HECO also estimates that the development and execution of a single production simulation run takes about 16 hours and would cost approximately $880.

Production Costing Model
Advisory Group

PURPOSE

The purpose of the Production Costing Model ("PCM") Advisory Group was to advise each of the HECO utilities in its choice of a PC-based, commercially available production costing model, which is capable of appropriately simulating the operation of

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[1] For HECO, the recipients at this time would be H-Power, Tesoro and Chevron. For MECO, the recipients at this time would be HC&S and Kaheawa Wind Power. For HELCO, the recipients at this time would be Wailuku River Hydro, Hawi Renewable Development, Apollo Energy Corp. and Puna Geothermal Ventures.

the Oahu, Hawaii and Maui Island systems. The choice of the appropriate model was made solely by each of the HECO utilities.

MEMBERSHIP

The members of the PCM Advisory Group included one representative each from Mauna Kea Power, HSPA, the Consumer Advocate, Kauai Electric Company, DOD, HELCO, MECO, and the following departments of Hawaiian Electric Company: Energy Services, Regulatory Affairs, Generation Planning, Production, and System Operations. The PCM Advisory Group was chaired by the representative from HECO's Generation Planning Department.

TERM

The PCM Advisory Group was an ad hoc committee formed for the specific purpose of advising each of the HECO utilities in its choice of a production costing model as stated above. Meeting discussion was limited to this objective. The PCM Advisory Group was disbanded once the choice of a model had been made.

PCM ADVISORY GROUP

On April 7, 1997, the HECO utilities held a PCM Advisory Group Meeting. The topics discussed at the meeting included selection criteria for an appropriate model, technical comparison of candidate models, and evaluation of the recommended model P-Month. (A copy of the presentation material is attached.)

In January 1997, the HECO utilities acquired the P-Month PC-based production simulation model. P-Month has been used by the HECO utilities to perform production simulations to forecast generating unit energy production, fuel consumption, fuel costs, operating hours, startups, and variable operations and maintenance costs. The model has been used for the production simulation results utilized in numerous dockets, including: MECO 1999 Test Year Rate Case (Docket No. 97-0346), HELCO 2000 Test Year Rate Case (Docket No. 99-0207) and HECO 2005 Test Year Rate Case (Docket No. 04-0113).

CONSUMER ADVOCATE ACCESS TO THE MODEL

The Consumer Advocate has requested that each of the HECO utilities make the P-Month model, as customized for the HECO utilities' systems, available to the Consumer Advocate. The HECO utilities have agreed to allow the Consumer Advocate access to a copy of the customized P-Month model. The Consumer Advocate shall be responsible for payment to the software vendor for the annual licensing fee for its copy of the model. The HECO utilities have agreed to provide the Consumer Advocate with an orientation session on the customized P-Month model, and such initial assistance as may be reasonably requested, without charge to the Consumer Advocate. If after obtaining its copy of the customized P-Month model the Consumer Advocate requests that the HECO utilities run a reasonable number of scenarios for the purpose of determining short term avoided fuel costs, charges for these runs shall be in accordance with provision 2. above.

OBJECTIONS TO THE MODEL

The parties reserve the right to object to the P-Month model due to the cost of obtaining the software for their use. These objections will be forwarded to the PUC for its consideration.

Production Costing Model Advisory Group Meeting

April 7, 1997

Hawaiian Electric Company, Inc.

Production Costing Model

The HECO utilities will use a PC-based, commercially available, production costing model (PCM) once the appropriate model has been identified and acquired. An *ad hoc* advisory group (AG) will be formed to assist each of the HECO utilities in its choice of an appropriate model.

Docket No. 7310, Stipulation to Resolve Proceeding, Exhibit A

Purpose of the PCM AG

- The purpose of the PCM AG is to advise each of the HECO utilities in its choice of a PC-based, commercially available production costing model, which is capable of appropriately simulating the operation of the Oahu, Hawaii and Maui systems.
- The choice of the appropriate model will be made by each of the HECO utilities.

Scheduled Meetings

- PCM AG organization, elements of an appropriate production costing model
- Review progress made, compare literature
- Presentation and review of HECO's production model choice

Today's Situation

- HECO re-organized in 1995
- Prior to the re-organization:
  - The former Rates & Regulatory Affairs Department computed as-available avoided cost and completed production costing analysis to support rate cases
  - The former Generation Planning Department computed long-term avoided cost for use in negotiations with NUG project developers

Exhibit A
Page 7 of 25

Today's Situation (cont.)

- After the re-organization:
  - As-available avoided cost calculations performed by the Energy Services Department
  - production simulation runs for rate making support and long-term avoided cost will be provided by the Power Supply Planning & Engineering Department (PSP&ED)
  - As-available avoided cost calculations will transition to PSP&ED once a D&O for Docket No. 7310 is issued or when production costing runs are required

Exhibit A
Page 8 of 25

Re-Organization Impact

- HECO's PSP&ED will chair the PCM Advisory Group

Other Organizational Matters

- Minutes
- Other items

Exhibit A
Page 10 of 25

Elements of An Appropriate Model (Selection Criteria)

- Commercially available
- PC based
- PC requirements (CPU type/speed, RAM)
- Ease of use
- Appropriate for range of applications
  - 7310, rate making support, revenue & fuel budgeting, IRP prodsim, unit commit and dispatch analysis, other short-term analysis

Elements/Criteria (cont.)

- Economical
- Can model as-available avoided cost as stipulated
- Ability to model HECO special needs
  - QLPU (commitment and dispatch), LOLH, Variable O&M ($/hr, $/MWh)
- Customer Support

Elements/Criteria (cont.)

- Technical criteria
  - dispatch load profile (8760, weekly...)
  - probabilistic or hourly monte carlo
  - dispatch method (subperiod load curve, hourly)
  - resource types (CT, CC, IPP, PS, CAES)
  - no. of dispatch segments
  - automatic fuel escalation, actual fuel cost input
  - spinning reserve modeling (capability to vary spinning requirement)
  - seasonal variations

Elements/Criteria (cont.)

- Technical criteria (cont.)
  - hourly results
  - unit commitment
  - marginal cost
  - emissions (types, dispatch)
  - reliability indices
  - batch run capability (multi-year, multi-scenario)

Elements/Criteria (cont.)

- Quick Load Pick-up (HECO only)
  - There must be enough generation running in economic dispatch so that the sum of the 3-second quick load pick-up available from all running units, not including the most heavily loaded unit, plus the loads of all other running units must be equal or exceed 95% of the hourly system load
    - » if QLPU not met, then adjust dispatch
    - » if QLPU still not met, then commit next unit
  - Not a standard feature in production costing models

Elements/Criteria (cont.)

- Variable O&M ($/hr, $/MWh)
  - Both provided by the HECO utilities (and used in in-house model)
  - Standard feature in production costing models is $/MWh only
  - Estimating $/hr component in terms of $/MWh has disadvantages
    - » may affect dispatch if utilities move to fuel + O&M dispatch
    - » $/hr component should only affect unit commit in a fuel + O&M dispatch

Exhibit A
Page 16 of 25

Elements/Criteria (cont.)

- Loss of Load Hours/Expected Unserved Energy
  - cumulant method of computation are standard in production costing models
  - experiencing difficulties with cumulant method in HECO IRP-2
  - foresee more analysis in this area (competition & infrastructure docket, renewables…)
    - » need to explore alternatives to cumulant methods (e.g., piece-wise linear approaches or numerical convolution)

Candidate Prodsim Models

- Enpro
- PMONTH
- Promod IV
- Prosym

Exhibit A
Page 18 of 25

Technical Comparison of Prodsim Models

- First screening was based on literature review
  - effective hands-on trial period will require training on each production costing model, user-subroutine development of QLPU for each model, and testing for each island utility
    - » too expensive, too time consuming

Exhibit A
Page 19 of 25

Summary

- Standard technical capabilities of each model (based on literature review) are, for the most part, similar
- Each model is "proven" - having been available for several years

Exhibit A
Page 20 of 25

Summary (cont.)

- QLPU modeling provided better insight in selecting a more appropriate model
  - using a spinning reserve restriction on capacity segments overestimates unit commitment
  - PPlus provided a more appropriate alternative to model HECO's QLPU philosophy

Summary (cont.)

- PPlus provides a numerically correct LOLH/EUE model that works within the PMONTH GUI (product: PREL)
- PPlus willing to re-write unit commit algorithm to include $/hr variable O&M
- PPlus provided most economical package
- Next step: Test PMONTH and PREL

Exhibit A
Page 22 of 25

Evaluation of PMONTH and PREL

- Paid for training and QLPU user subroutine development
- Training - programs are easy to use, approach is methodical and logical
- Customer support - fast and supportive. Programmers are experienced with practical utility matters (evidenced by QLPU modeling)

Exhibit A
Page 23 of 25

Evaluation of PMONTH and PREL (cont.)

- To date, modeling of each system has been reasonable
  - PPlus modified PMONTH and PREL to accept and compute Lanai/Molokai data in kW
- Trial period ends May 13.

Exhibit A
Page 24 of 25

Recommendation

- Accept PMONTH as the production costing model for Docket No. 7310.

PRODUCTION SIMULATION
AND AVOIDED FUEL COST

1. The QF in/QF out methodology will be used to determine avoided fuel cost for the on- and off-peak periods for HECO, HELCO, and the Maui Division of MECO. The amount of QF energy removed will be equal to the estimated amount of as-available energy. If less than 8,760 mwh of as-available energy is anticipated for that year, the avoided fuel cost will be determined on the basis of 8,760 mwh (1 mw) of as-available energy. The ratio of estimated as-available energy to estimated net-to-system energy (the "as-available energy ratio") will not exceed ten percent (10%) of the total net-to-system energy when determining avoided energy costs for energy payments based on Schedule Q, or on the utility's on-peak and off-peak avoided costs for energy filed with the Commission (the "filed avoided energy costs"), to QFs with existing power purchase agreements ("PPAs") as of the date of this Updated 7310 Stipulation. If PPAs for the purchase of as-available energy are entered into after the date of the Updated 7310 Stipulation with payment rates based on the utility's filed avoided energy costs ("new PPAs"), which is not expected to be the case due to the amendment of Section 269-27.2(c) in 2006, and the as-available energy ratio exceeds ten percent (10%) as a result of the new PPAs, then the filed avoided energy costs for the new PPAs will be based only on the energy costs avoided by the new PPAs.

2. The production costing model will simulate, as much as possible, the actual anticipated operation of the generating resources.

3. The following proxy units will be used for the Lanai and Molokai Divisions of MECO:

<u>Lanai: Miki Basin Generating Station</u>
On peak proxy:
Six (6) medium speed EMD diesel engine generators, LL-1 through LL-6 (1,000 kw each)

Off peak proxy:
Two (2) medium speed Caterpillar diesel engine generators, LL-7 and LL-8 (2,200 kW each)

<u>Molokai: Palaau Generating Station</u>
On peak proxy:
Two (2) high speed Caterpillar diesel engine generators, P-1 and P-2 (1,250 kw each)
Four (4) high speed Cummins diesel engine generators, P-3 through P-6 (970 kW each)

Off peak proxy:
Three (3) medium speed Caterpillar diesel engine generators, P-7, P-8 and P-9 (2,200 kW each)

4. The new methodology will be implemented 4 months after the issuance of the D&O

approving this st... ation, including 2 months for the ...ecution of the production simulations, 1 month for review by the parties, and 1 month for any additional simulations. The initial updated avoided energy cost rates and Schedule Q rates would go into effect on the 1st day of the month following this 4 month period. The schedule for ensuing updates is addressed in item 5. below.

5. The model would be updated annually and the resulting avoided fuel costs and production simulations would be available on October 1 of each year for the ensuing year. The fuel price used in the annual runs will be contract prices and/or price estimates effective September 1. The parties and recipients shall have the opportunity to review and provide comments on the resulting avoided fuel costs and production simulation results, and any comments shall be emailed to the other parties and recipients by November 15. As addressed in Exhibit A, the HECO utilities have agreed to run a reasonable number of scenarios at the request of the other parties and recipients for a reasonable charge. Requests for additional scenarios shall be made by November 15 to allow the HECO utilities the necessary time to do any additional production simulations. The updated avoided fuel costs shall take effect on January 1 for the ensuing year.

   As addressed in Exhibit A, the HECO utilities will email to the other parties and recipients a copy of the production costing model calibrated input data set. The HECO utilities will also provide to the other parties and recipients, by email, updated Exhibit C modeling assumptions used in the production costing model. If requested by an entity with a power purchase agreement for a facility with a nameplate capacity of less than one megawatt being paid the avoided energy costs and Schedule Q rates determined in accordance with this proceeding, the HECO utilities will provide by email the aforementioned information to the requesting entity.

6. The model will include any changes anticipated in the amount of firm capacity available. Capacity additions (retirements) will be included in the simulation on the date of the scheduled addition (retirement). The pre- and post-addition (retirement) avoided fuel costs will be determined using the production simulation results for the pre- or post-addition (retirement) period.

   A monthly change of more than 5% from the anticipated level of available firm capacity resources (due, for example, to an extended forced outage) if known one month prior to the beginning of that month, will require the re-execution of the production simulation for that month.

7. The avoided fuel costs will be updated monthly for changes in fuel prices using as weights the amount of plant generation, as shown in Attachment 1. Purchased energy avoided will be included at its avoided fuel cost.

8. The avoided fuel costs determined using this methodology will be applied to energy provided by existing purchased power producers whose payment rates are based on the filed avoided cost.

MODELING ASSUMPTIONS

The modeling assumptions set forth below are intended to reasonably reflect the current, actual operating conditions for the listed electric companies. The modeling assumptions to be used in the production simulations made available on October 1 of each year may be updated to reflect any changes in the actual operating conditions of the listed electric companies. The parties expressly reserve the right to proffer, use and defend different modeling assumptions in proceedings including, but not limited to, general rate case dockets, IRP Plan dockets, Purchase Power Agreement dockets, Adequacy of Supply reports, and proceedings convened to examine avoided cost methodology. As addressed in Exhibit B, the HECO utilities will provide to the other parties and recipients, by email, updated Exhibit C modeling assumptions used in the production costing model. In addition, if requested by an entity with a power purchase agreement for a facility with a nameplate capacity of less than one megawatt being paid the avoided energy costs and Schedule Q rates determined in accordance with this proceeding, the HECO utilities will also provide by email to the requesting entity the updated Exhibit C modeling assumptions.

HELCO

1. Model Hill 5, Hill 6, Puna steam unit, Puna Geothermal Ventures ("PGV"), and Hamakua Energy Partners ("HEP") as baseloaded.
2. HEP is modeled at 60 MW maximum.
3. Forced outage rates based on 12-month average (June 2004-May 2005) for HELCO-owned units. PGV forced outage rate based on 5-year average (2000-2004). HEP forced outage rate based on 3-year average (2002-2004).
4. Regulating reserve of 3 MW to 5 MW at different times throughout the day without Hawi Renewable Development ("HRD") and repowered Apollo Energy Corp. in service. (Note: The amount of regulating reserve may need to be increased in the future as more as-available generation is integrated into the system.)
5. ABC curves based upon current actual data.

MECO (Maui Division)

1. Model Kahului units 3-4, Maalaea diesel unit 13, and the combined cycle unit (Maalaea DTCC No. 1) as baseloaded.
2. Forced outage rates based on 5-year average (2000-2004) where available.
3. ABC curves based on 5-year average (2000-2004) where available.
4. Regulating reserve of 4 MW throughout the day without Kaheawa Wind Power ("KWP") in service. Regulating reserve of 7 MW throughout the day with KWP in service. (Note: The amount of regulating reserve may need to be increased in the future as more as-available generation is integrated into the system.)

HECO

1. Model Kahe 1-6, Waiau 7 and 8, AES, HPOWER, and Kalaeloa as baseloaded.
2. HECO unit and IPP forced outage rates are consistent with rebuttal testimony in the HECO Test Year 2005 Ratecase, Docket No. 04-0113.
3. ABC curves are consistent with rebuttal testimony in the HECO Test Year 2005 Ratecase, Docket No. 04-0113.
4. No spinning reserves for as-available energy.

Hawaiian Electric Company, Inc.

AVOIDED ENERGY COST RATES
ADJUSTED FOR FUEL PRICES EFFECTIVE SEPTEMBER 2005

Line		On-Peak	Off-Peak	
(1)	Avoided Fuel Cost (Attachment 1)	9.525	8.406	¢/kwh
(2)	Avoided O&M Cost (Attachment 2)	0.028	0.022	¢/kwh
(3)	Avoided Working Cash (Attachment 3)	0.051	0.045	¢/kwh
(4)	Avoided Fuel Inventory (Attachment 4)	0.029	0.029	¢/kwh
(5)	Total Avoided Energy Cost Rates	9.633	8.502	¢/kwh
(6)	Total Weighted Avoided energy Cost Rate*	9.16		¢/kwh

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

Hawaiian Electric Company, Inc.

AVOIDED FUEL COST RATES
ADJUSTED FOR FUEL PRICES EFFECTIVE SEPTEMBER 2005

Line	On-Peak Avoided Fuel Cost Rates	
(1)	On-Peak Avoided Cost Rate	8.919 ¢/kwh
(2)	On-Peak Adjustment Factor (Line 14)	1.068
(3)	Adjusted On-Peak Avoided Cost Rate (Line 1 x Line 2)	9.525 ¢/kwh
	Off-Peak Avoided Fuel Cost Rates	
(4)	Off-Peak Avoided Cost Rate	7.930 ¢/kwh
(5)	Off-Peak Adjustment Factor (Line 22)	1.060
(6)	Adjusted Off-Peak Avoided Cost Rate (Line 4 x Line 5)	8.406 ¢/kwh

ADJUSTMENT FACTORS

	On-Peak					
		Fuel Price		Fuel Price	% of	Wtd Fuel
	Generating Facility	ECA Filing	Prod Sim	Ratio	Avoid Gen	Price Ratio
(7)	Honolulu[1]	914.59	856.55	1.0678	8.66%	0.0925
(8)	Kahe[1]	914.59	856.55	1.0678	57.09%	0.6096
(9)	Waiau[1]	914.59	856.55	1.0678	33.39%	0.3565
(10)	Waiau Diesel (W9-10)[1]	1363.62	1259.78	1.0824	0.86%	0.0093
(11)	AES[2]	2.562	2.562	1.0000	0.00%	0.0000
(12)	Kalaeloa[2]	8.843	8.843	1.0000	0.00%	0.0000
(13)	H-Power[2]	0.000	0.000	0.0000	0.00%	0.0000
(14)	Total				100.00%	1.0679

	Off-Peak					
		Fuel Price		Fuel Price	% of	Wtd Fuel
	Generating Facility	ECA Filing	Prod Sim	Ratio	Avoid Gen	Price Ratio
(15)	Honolulu[1]	914.59	856.55	1.0678	-0.16%	-0.0017
(16)	Kahe[1]	914.59	856.55	1.0678	71.73%	0.7659
(17)	Waiau[1]	914.59	856.55	1.0678	16.03%	0.1712
(18)	Waiau Diesel (W9-10)[1]	1363.62	1259.78	1.0824	0.00%	0.0000
(19)	AES[2]	2.562	2.562	1.0000	0.00%	0.0000
(20)	Kalaeloa[2]	8.843	8.843	1.0000	12.41%	0.1241
(21)	H-Power[2]	0.000	0.000	0.0000	0.00%	0.0000
(22)	Total				100.01%	1.0595

Hawaiian Electric Company, Inc.
ENERGY COST ADJUSTMENT FILING

Line		
1	Effective Date	- September 1, 2005
2	Supercedes Factor	- August 1, 2005

GENERATION COMPONENT

Line		
	FUEL PRICES, ¢/MBTU	
3	Honolulu	914.59
4	Kahe	914.59
5	Waiau-Steam	914.59
6	Waiau-Waste	0.00
7	Waiau-Diesel	1,363.62
	BTU MIX, %	
8	Honolulu	3.67
9	Kahe	67.22
10	Waiau-Steam	28.96
11	Waiau-Waste	0.00
12	Waiau-Diesel	0.15
13	COMPOSITE COST OF GENERATION, ¢/MBTU	915.26
14	% Input to system kWh Mix	59.40
15	Efficiency Factor, Mbtu/kWh	0.011170
16	WEIGHTED COMPOSITE GEN COST, ¢/KWH (Line 13 x 14 x 15)	6.07273
17	BASE GENERATION COST, ¢/Mbtu	287.83
18	Base % Input to System kWh Mix	58.64
19	Efficiency Factor, Mbtu/kWh	0.011170
20	WEIGHTED BASE GEN COST, ¢/KWH (Line 17 x 18 x 19)	1.88531
21	Cost Less Base (Line 16 - 20)	4.18742
22	Revenue Tax Req Multiplier	1.0975
23	GENERATION FACTOR, ¢/KWH (Line 21 x 22)	4.59569

PURCHASED ENERGY COMPONENT

Line					
	PURCHASED ENERGY PRICE - ¢/KWH				
24	THC	- On Peak		11.860
25		- Off Peak		9.010
26	HRRV	- On Peak		10.697
27		- Off Peak		8.157
28	HRRV	- On Peak	(excess)	10.697
29		- Off Peak	(excess)	8.157
30	Chevron	- On Peak		11.860
31		- Off Peak		9.010
32	Kalaeloa			8.843
33	AES-HI			2.562
	PURCHASED ENERGY KWH MIX, %			
34	THC	- On Peak		0.07
35		- Off Peak		0.05
36	HRRV	- On Peak		5.96
37		- Off Peak		2.57
38	HRRV	- On Peak	(excess)	0.00
39		- Off Peak	(excess)	1.68
40	Chevron	- On Peak		0.00
41		- Off Peak		0.00
42	Kalaeloa			45.71
43	AES-HI			43.96
44	COMPOSITE COST OF PURCHASED ENERGY, ¢/KWH			6.165
45	% Input to System kWh Mix			40.60
46	WTD CMP PURCH ENRGY COST, ¢/KWH (Line 44 x 45)			2.50299
47	BASE PURCH ENERGY COMP COST			3.005
48	Base % Input to System kWh Mix			41.36
49	WTD BASE PRCH ENERGY COST, ¢/KWH (Line 47 x 48)			1.24287
50	Cost Less Base (Line 46 - 49)			1.26012
51	Loss Factor			1.059
52	Revenue Tax Req Multiplier			1.0975
53	PURCHASED ENERGY FACTOR, ¢/KWH (Line 50 x 51 x 52)			1.46458

Line		
54	Fuel & Purchased Energy Factor, ¢/kWh (Line 23 + 53)	6.06027
55	Adjustment, ¢/kWh	0.000
56	ECA Reconciliation Adjustment, ¢/kWh	0.028
57	ENERGY COST ADJUSTMENT FACTOR, ¢/KWH (Line 54 + 55 + 56)	6.088

SUMMARY STATISTICS FOR HECO AVOIDED O&M
Docket No. 7310

OFF-PEAK					
UNIT TYPE	% Avoided	Rate (¢/kwh)			
	MWH	Consum.	Maint.	Total	Net
HECO					
Steam	87.60%	0.025	0.000	0.025	0.022
CTs	0.00%	0.000	0.000	0.000	0.000
AES	0.00%	0.000	0.000	0.000	0.000
KPLP	12.40%	0.000	0.000	0.000	0.000
H-POWER	0.00%	0.000	0.000	0.000	0.000
Total	100.00%				0.022
ON-PEAK					
UNIT TYPE	% Avoided	Rate (¢/kwh)			
	MWH	Consum.	Maint.	Total	Net
HECO					
Steam	99.14%	0.025	0.000	0.025	0.025
CTs	0.86%	0.000	0.395	0.395	0.003
AES	0.00%	0.000	0.000	0.000	0.000
KPLP	0.00%	0.000	0.000	0.000	0.000
H-POWER	0.00%	0.000	0.000	0.000	0.000
Total	100.00%				0.028
TOTAL					
UNIT TYPE	% Avoided	Rate (¢/kwh)			
	MWH	Consum.	Maint.	Total	Net
HECO					
Steam	94.32%	0.025	0.000	0.025	0.024
CTs	0.50%	0.000	0.395	0.395	0.002
AES	0.00%	0.000	0.000	0.000	0.000
KPLP	5.18%	0.000	0.000	0.000	0.000
H-POWER	0.00%	0.000	0.000	0.000	0.000
Total	100.00%				0.026

Hawaiian Electric Company, Inc

AVOIDED WORKING CASH CALCULATIONS

Avoided Working Cash Impact for Fuel and Purchased Eenrgy:

$$= \frac{\text{purchased energy payment lag days - fuel oil payment lag days}}{365}$$

$$\times \frac{\text{(rate of return on rate base) - (weighted cost of debt x composite income tax rate)}}{\text{(1 - composite income tax rate)}}$$

x avoided fuel cost

OR,

Avoided Working Cash Impact:

= avoided fuel working cash factor x avoided fuel cost

		On-Peak	Off-Peak
(1)	fuel oil payment lag days (a1)	20	20
(2)	purchased energy payment lag days (b)	35	35
(3)	rate of return on rate base (c)	9.160%	9.160%
(4)	weighted cost of debt (d)	3.09%	3.09%
(5)	composite income tax rate (e)	38.910%	38.910%
(6)	avoided fuel working cash factor	0.535%	0.535%
(7)	avoided fuel cost (¢/kwh)	9.525	8.406
(8)	avoided fuel working cash (¢/kwh)	0.051	0.045

See reference notes on Exhibit D page 7.

Hawaiian Electric Company, Inc

AVOIDED WORKING CASH CALCULATIONS

Avoided Working Cash Impact for O&M:

$$= \frac{\text{Purchased energy payment lag days - O\&M payment lag days}}{365}$$

$$\times \frac{\text{(rate of return on rate base) - (weighted cost of debt x composite income tax rate)}}{\text{(1 - composite income tax rate)}}$$

$$\times \text{ avoided O\&M cost}$$

OR,

Avoided Working Cash Impact:

= avoided O&M working cash factor x avoided O&M cost

		On-Peak	Off-Peak
(1)	O&M payment lag days (a2)	40	40
(2)	purchased energy payment lag days (b)	35	35
(3)	rate of return on rate base (c)	9.160%	9.160%
(4)	weighted cost of debt (d)	3.09%	3.09%
(5)	composite income tax rate (e)	38.910%	38.910%
(6)	avoided O&M working cash factor	-0.178%	-0.178%
(7)	avoided O&M cost (¢/kwh)	0.028	0.022
(8)	avoided O&M working cash (¢/kwh)	0.000	0.000
(9)	total avoided working cash (¢/kwh) (Exhibit D page 5, line 8 plus Exhibit D page 6, line 8)	0.051	0.045

References:

(a1) Docket No. 7766, D&O No. 14412, Exhibit B, page 2 of 2.

(a2) Docket No. 7766, D&O No. 14412, Exhibit B, page 2 of 2, O&M Nonlabor payment lag days.

(b) Based on the specific payment provisions of each purchased power agreement. 35 days represents payment 20 days following the end of the month.

(c) Docket No. 7766, D&O No. 14412, page 100.

(d) Weighted capital cost on short term debt = 0.33%
Weighted capital cost on long term debt = 2.76%
Docket No. 7766, D&O No. 14412, page 100

(e) Composite income tax rate = 38.9098%
Docket No. 7766, D&O No. 14412, Exhibit A, page 4 of 4.

Hawaiian Electric Company, Inc

AVOIDED FUEL INVENTORY CALCULATIONS

Avoided Fuel Inventory Impact:

$$= \frac{\text{days of fuel inventory}}{365} \times \text{million btus (mbtus) avoided} \times \$/\text{mbtu}$$

$$\times \frac{(\text{rate of return on rate base}) - (\text{weighted cost of debt} \times \text{composite income tax rate})}{(1 - \text{composite income tax rate})}$$

$$/ \ \text{as-available QF energy}$$

		On and Off-Peak	
		Industrial Fuel	Diesel Fuel
(1)	days of fuel inventory (a)	30	30
(2)	fuel avoided (MBTU) (b)	82,229	898
(3)	fuel price ($/mbtu) (c)	2.8626	3.9311
(4)	rate of return on rate base (d)	9.160%	9.160%
(5)	weighted cost of debt (e)	3.09%	3.09%
(6)	composite income tax rate (f)	38.910%	38.910%
(7)	as-available QF energy (mwh)	8,760	8,760
(8)	avoided fuel inventory (¢/kwh)	0.029	0.000
(9)	total avoided fuel inventory (¢/kwh)	0.029	

See reference notes on following page.

References:

(a) Docket No. 7766, D&O No. 14412, p. 41.

(b) Production Simulation dated 07/26/05 (Base) & 08/2/05 (Alternate)

(c) Docket No. 7766, D&O No. 14412, page 41. HECO-R-239 pg1.
Residual Fuel Price: 17.7480/bbl ÷ 6.2 = $2.8626/mbtu
Diesel Fuel Price: $23.0363/bbl ÷ 5.86 = $3.9311/mbtu

(d) Docket No. 7766, D&O No. 14412, page 100.

(e) Weighted capital cost on short term debt = 0.33%
Weighted capital cost on long term debt = 2.76%
Docket No. 7766, D&O No. 14412, page 100.

(f) Composite income tax rate = 38.9098%
Docket No. 7766, D&O No. 14412, Exhibit A, page 4 of 4

Hawaii Electric Light Company, Inc

AVOIDED ENERGY COST RATES
ADJUSTED FOR FUEL PRICES EFFECTIVE SEPTEMBER 2005

Line		On-Peak	Off-Peak	
(1)	Avoided Fuel Cost (Attachment 1)	16.153	11.213	¢/kwh
(2)	Avoided O&M Cost (Attachment 2)	0.639	0.367	¢/kwh
(3)	Avoided Working Cash (Attachment 3)	0.077	0.054	¢/kwh
(4)	Avoided Fuel Inventory (Attachment 4)	0.053	0.053	¢/kwh
(5)	Total Avoided Energy Cost Rates	16.922	11.687	¢/kwh

Total Weighted Avoided energy Cost Rate*	14.741		¢/kwh

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

Hawaii Electric Light Company, Inc

AVOIDED FUEL COST RATES
ADJUSTED FOR FUEL PRICES EFFECTIVE SEPTEMBER 2005

Line		
	On-Peak Avoided Fuel Cost Rates	
(1)	On-Peak Avoided Cost Rate	14.874 cents/kwh
(2)	On-Peak Adjustment Factor (Line 18)	1.086
(3)	Adjusted On-Peak Avoided Cost Rate (Line 1 x Line 2)	16.153 cents/kwh
	Off-Peak Avoided Fuel Cost Rates	
(4)	Off-Peak Avoided Cost Rate	10.373 cents/kwh
(5)	Off-Peak Adjustment Factor (Line 30)	1.081
(6)	Adjusted Off-Peak Avoided Cost Rate (Line 4 x Line 5)	11.213 cents/kwh

ADJUSTEMENT FACTORS

	On-Peak					
		Fuel Price		Fuel Price	% of Avoid	Wtd Fuel
	Generating Facility	ECA Filing	Prod Sim	Ratio	Gen	Price Ratio
(7)	Hill	774.29	807.33	0.9591	5.27%	0.0505
(8)	Shipman	774.29	807.33	0.9591	0.16%	0.0015
(9)	Puna	786.04	819.08	0.9597	0.00%	0.0000
(10)	Waimea	1,463.36	1334.87	1.0963	0.83%	0.0091
(11)	Kanoelehua	1,449.24	1320.01	1.0979	1.10%	0.0121
(12)	Keahole	1,469.52	1341.03	1.0958	54.41%	0.5962
(13)	Puna CT3	1,449.38	1320.89	1.0973	24.81%	0.2722
	Dispersed	0.00	1504.33	0.0000	0.23%	0.0000
(14)	PGV	16.680	16.680	1.0000	0.00%	0.0000
(15)	PGV additional	14.197	11.780	1.2052		0.0000
(16)	HCPC	0.000	0.000	0.0000	0.00%	0.0000
(17)	HEP	11.626	10.590	1.0978	13.19%	0.1448
(18)	Total				100.00%	1.0864
	Off-Peak					
		Fuel Price		Fuel Price	% of Avoid	Wtd Fuel
	Generating Facility	ECA Filing	Prod Sim	Ratio	Gen	Price Ratio
(19)	Hill	774.29	807.33	0.9591	5.72%	0.0549
(20)	Shipman	774.29	807.33	0.9591	0.02%	0.0002
(21)	Puna	786.04	819.08	0.9597	5.85%	0.0561
(22)	Waimea	1,463.36	1334.87	1.0963	0.37%	0.0041
(23)	Kanoelehua	1,449.24	1320.01	1.0979	0.90%	0.0099
(24)	Keahole	1,469.52	1341.03	1.0958	15.51%	0.1700
(25)	Puna CT3	1,449.38	1320.89	1.0973	2.17%	0.0238
	Dispersed	0.00	1504.33	0.0000	0.03%	0.0000
(26)	PGV	13.500	13.500	1.0000	0.00%	0.0000
(27)	PGV additional	13.197	10.780	1.2242		0.0000
(28)	HCPC	0.000	0.000	0.0000	0.00%	0.0000
(29)	HEP	11.626	10.590	1.0978	69.43%	0.7622
(30)	Total				100.00%	1.0812

Hill, Shipman, Puna, Waimea, Kanoelehua ,Keahole, Puna CT3 fuel price is from 3rd q filing in ¢/mbtu
PGV, HCPC, HEP fuel price is avoided energy cost from 3rd q filing (not costs in Pmonth) in ¢/kwh

HAWAII ELECTRIC LIGHT COMPANY, INC.
ENERGY COST ADJUSTMENT (ECA) FILING

Line		
1	Effective Date	September 1, 2005
	Supercedes Factors of	August 1, 2005
	HELCO GENERATION COMPONENT	
	FUEL PRICES, ¢/mmbtu	
2	Hilo Industrial	774.29
3	Puna Industrial	786.04
4	Keahole Diesel	1,469.52
5	Waimea Diesel	1,463.36
6	Hilo Diesel	1,449.24
7	Puna Diesel	1,449.38
8	Wind	0.00
9	Hydro	0.00
	BTU MIX, %	
10	Hilo Industrial	40.62
11	Puna Industrial	16.58
12	Keahole Diesel	33.96
13	Waimea Diesel	1.04
14	Hilo Diesel	2.33
15	Puna Diesel	4.85
16	Wind	0.27
17	Hydro	0.35
		100.00
18	COMPOSITE COST OF GENERATION, ¢/mmbtu	1,063.17
19	% Input to System kwh Mix	53.40
20	Efficiency Factor, mmbtu/kwh	0.014629
21	WEIGHTED COMPOSITE GEN COST, ¢/kwh (lines (18x19x20))	8.30536
22	BASE GEN. COST, ¢/mmbtu	469.72
23	Base % Input to Sys kwh Mix	27.09
24	Efficiency Factor, mmbtu/kwh	0.014629
25	WEIGHTED BASE GEN COST, ¢/kwh (lines (22x23x24))	1.8615
26	COST LESS BASE (line(21-25))	6.44386
27	Multiplier to Include Revenue Tax Requirement	1.0975
28	GENERATION FACTOR, ¢/kwh (line (26x27))	7.07214

Line	PURCHASED ENERGY COMPONENT		
	PURCHASED ENERGY PRICE, ¢/kwh		
27	not used		
28	not used		
29	HEP		11.626
30	PGV	On Peak	16.680
31	PGV	Off Peak	13.500
32	PGV	On Peak Add'l	14.197
33	PGV	Off Peak Add'l	13.197
34	Wailuku Hydro	On Peak	16.680
35	Wailuku Hydro	Off Peak	13.500
36	Other (>100 KW)	On Peak	14.390
37	Other (>100 KW)	Off Peak	11.777
38	Other (<100 KW)		15.170
	PURCHASED ENERGY KWH MIX, %		
39	not used		
40	not used		
41	HEP		64.99
42	PGV	On Peak	16.99
43	PGV	Off Peak	10.68
44	PGV	On Peak Add'l	1.36
45	PGV	Off Peak Add'l	0.00
46	Wailuku Hydro	On Peak	2.27
47	Wailuku Hydro	Off Peak	1.64
48	Other (>100 KW)	On Peak	1.41
49	Other (>100 KW)	Off Peak	0.64
50	Other (<100 KW)		0.02
			100.00
51	COMPOSITE COST OF PURCHASED ENERGY, ¢/kwh		12.906
52	% Input to System kwh Mix		46.60
53	WEIGHTED COMP. PURCH. ENERGY COST, ¢/kwh (lines (51x52))		6.01420
54	BASE PURCHASED ENERGY COMPOSITE COST, ¢/kwh		6.404
55	Base % Input to Sys kwh Mix		72.91
56	WEIGHTED BASE PURCH ENERGY COST, ¢/kwh (lines (54x55))		4.66916
57	COST LESS BASE(line(53-56))		1.34504
58	Loss Factor		1.087
59	Multiplier to Include Revenue Tax Requirement		1.0975
60	PURCHSD ENERGY FCTR, ¢/k (lines (57x58x59))		1.60461

LINE	SYSTEM COMPOSITE	
61	FUEL AND PURCHASED ENERGY FACTOR, ¢/kwh (lines (28+60))	8.67675
62	Not Used	0.000
63	Not Used	0.000
64	ECA Reconciliation Adjustment	(0.092)
65	ECA FACTOR, ¢/kwh (line(61+62+63+64))	8.585

OFF-PEAK					
UNIT TYPE	% Avoided MWH	Rate (¢/kwh)			
		Consum.	Maint.	Total	Net
Base Steam	5.72%	0.083	0.000	0.083	0.005
Interm. Steam					
Shipman	0.02%	0.191	0.466	0.657	0.000
Puna	5.85%	0.137	0.000	0.137	0.008
CTs	17.80%	0.081	0.701	0.782	0.139
Diesel Units	1.18%	0.107	1.008	1.115	0.013
HEP	69.43%	0.108	0.182	0.290	0.201
HCPC	0.00%	0.000	0.000	0.000	0.000
PGV	0.00%	0.000	0.000	0.000	0.000
Total	100.00%				0.367
ON-PEAK					
UNIT TYPE	% Avoided MWH	Rate (¢/kwh)			
		Consum.	Maint.	Total	Net
Base Steam	5.27%	0.083	0.000	0.083	0.004
Interm. Steam					
Shipman	0.16%	0.191	3.305	3.496	0.005
Puna	0.00%	0.000	0.000	0.000	0.000
CTs	78.46%	0.091	0.512	0.603	0.473
Diesel Units	2.92%	0.114	1.032	1.146	0.033
HEP	13.19%	0.108	0.823	0.931	0.123
HCPC	0.00%	0.000	0.000	0.000	0.000
PGV	0.00%	0.000	0.000	0.000	0.000
Total	100.00%				0.639
TOTAL					
UNIT TYPE	% Avoided MWH	Rate (¢/kwh)			
		Consum.	Maint.	Total	Net
Base Steam	5.45%	0.083	0.000	0.083	0.005
Interm. Steam					
Shipman	0.10%	0.191	3.035	3.226	0.003
Puna	2.34%	0.137	0.000	0.137	0.003
CTs	54.18%	0.090	0.537	0.626	0.339
Diesel Units	2.22%	0.113	1.027	1.139	0.025
HEP	35.70%	0.108	0.324	0.432	0.154
HCPC	0.00%	0.000	0.000	0.000	0.000
PGV	0.00%	0.000	0.000	0.000	0.000
Total	100.00%				0.530

Hawaii Electric Light Company, Inc

AVOIDED WORKING CASH CALCULATIONS

Avoided Working Cash Impact for Fuel and Purchased Energy:

$$= \frac{\text{Purchased energy payment lag days - fuel oil payment lag days}}{365}$$

$$\times \frac{\text{(rate of return on rate base) - (weighted cost of debt x composite income tax rate)}}{\text{(1 - composite income tax rate)}}$$

$$\times \text{ avoided fuel cost}$$

OR,

Avoided Working Cash Impact:

$$= \text{avoided fuel working cash factor x avoided fuel cost}$$

		On-Peak	Off-Peak
(1)	fuel oil payment lag days (a1)	22	22
(2)	purchased energy payment lag days (b)	35	35
(3)	rate of return on rate base (c)	9.140%	9.140%
(4)	weighted cost of debt (d)	2.77%	2.77%
(5)	composite income tax rate (e)	38.910%	38.910%
(6)	avoided fuel working cash factor	0.470%	0.470%
(7)	avoided fuel cost (¢/kwh)	16.153	11.213
(8)	avoided fuel working cash (¢/kwh)	0.076	0.053

See reference notes on Exhibit E, page 7.

Hawaii Electric Light Company, Inc

AVOIDED WORKING CASH CALCULATIONS

Avoided Working Cash Impact for O&M:

$$= \frac{\text{Purchased energy payment lag days - O\&M payment lag days}}{365}$$

$$\times \frac{\text{(rate of return on rate base) - (weighted cost of debt x composite income tax rate)}}{\text{(1 - composite income tax rate)}}$$

x avoided O&M cost

OR,

Avoided Working Cash Impact:
= avoided O&M working cash factor x avoided O&M cost

		On-Peak	Off-Peak
(1)	O&M payment lag days (a2)	31	31
(2)	purchased energy payment lag days (b)	35	35
(3)	rate of return on rate base (c)	9.140%	9.140%
(4)	weighted cost of debt (d)	2.77%	2.77%
(5)	composite income tax rate (e)	38.910%	38.910%
(6)	avoided O&M working cash factor	0.145%	0.145%
(7)	avoided O&M cost (¢/kwh)	0.639	0.367
(8)	avoided O&M working cash (¢/kwh)	0.001	0.001
(9)	total avoided working cash (¢/kwh) (Exhibit E Page 5, line 8 plus Exhibit E Page 6, Line 8)	0.077	0.054

References:

(a1)	Docket No. 99-0207, D&O No. 18365, Exhibit B, page 2 of 2
(a2)	Docket No. 99-0207, D&O No. 18365, Exhibit B, page 2 of 2, O&M - Other payment lag days.
(b)	Based on the specific payment provisions of each purchased power agreement. 35 days represents payment 20 days following the end of the month.
(c)	Docket No. 99-0207, D&O No. 18365, page 76
(d)	Weighted capital cost on short term debt = 0.38% Weighted capital cost on long term debt = 2.39% Docket No. 99-0207, D&O No. 18365, page 76
(e)	Composite income tax rate = 38.9098% Docket No. 99-0207, D&O No. 18365, Exhibit A, page 4 of 4

Hawaii Electric Light Company, Inc

AVOIDED FUEL INVENTORY CALCULATIONS

Avoided Fuel Invetory Impact:

$$= \frac{\text{days of fuel invetory}}{365} \times \text{million btus (mbtus) avoided} \times \text{\$/mbtu}$$

$$\times \frac{\text{(rate of return on rate base)} - \text{(weighted cost of debt} \times \text{composite income tax rate)}}{\text{(1 - composite income tax rate)}}$$

$$/ \text{ as-availble QF energy}$$

		On and Off-Peak	
		Industrial Fuel	Diesel Fuel
(1)	days of fuel inventory (a)	24	30
(2)	fuel avoided (MBTU) (b)	37,825	262,905
(3)	fuel price ($/mbtu) (c)	4.7169	7.0375
(4)	rate of return on rate base (d)	9.140%	9.140%
(5)	weighted cost of debt (e)	2.77%	2.77%
(6)	compsite income tax rate (f)	38.910%	38.910%
(7)	as-available QF energy (MWH)	41,185	41,185
(8)	avoided fuel inventory (¢/kwh)	0.004	0.049
(9)	total avoided fuel inventory (¢/kwh)	0.053	

See reference notes on following page.

References:

(a)	Docket No. 99-0207, D&O No. 18365. HELCO-RWP-1950, page 55 of 64.
(b)	Production Simulation dated 08/02/05
(c)	HELCO Docket No. 99-0207, D&O 18365, pg 59. CA-502 pgs 9-14.
(d)	Docket No. 99-0207, D&O No. 18365, page 76.
(e)	Weighted capital cost on short term debt = 0.38% Weighted capital cost on long term debt = 2.39% Docket No. 99-0207, D&O No. 18365, page 76.
(f)	Composite income tax rate = 38.9098% Docket No. 99-0207, D&O No. 18365, Exhibit A, page 4 of 4.

Maui Electric Company, Ltd.
MAUI DIVISION
AVOIDED ENERGY COST RATES
ADJUSTED FOR FUEL PRICES EFFECTIVE SEPTEMBER 2005

Line		On-Peak	Off-Peak	
(1)	Avoided Fuel Cost (Attachment 1)	14.327	12.061	¢/kwh
(2)	Avoided O&M Cost (Attachment 2)	0.524	0.454	¢/kwh
(3)	Avoided Working Cash (Attachment 3)	0.011	0.009	¢/kwh
(4)	Avoided Fuel Inventory (Attachment 4)	0.043	0.043	¢/kwh
(5)	Total Avoided Energy Cost Rates	14.905	12.567	¢/kwh
(6)	Total Weighted Avoided energy Cost Rate*		13.930	¢/kwh

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

Maui Electric Company, Ltd.

AVOIDED FUEL COST RATES
ADJUSTED FOR FUEL PRICES EFFECTIVE SEPTEMBER 2005

Line	On-Peak Avoided Fuel Cost Rates		
(1)	On-Peak Avoided Cost Rate	13.571	¢/kwh
(2)	On-Peak Adjustment Factor (Line 10)	1.056	
(3)	Adjusted On-Peak Avoided Cost Rate (Line 1 x Line 2)	14.327	¢/kwh
	Off-Peak Avoided Fuel Cost Rates		
(4)	Off-Peak Avoided Cost Rate	11.586	¢/kwh
(5)	Off-Peak Adjustment Factor (Line 14)	1.041	
(6)	Adjusted Off-Peak Avoided Cost Rate (Line 4 x Line 5)	12.061	¢/kwh

ADJUSTMENT FACTORS

	On-Peak					
		Fuel Price (¢/MBTU)		Fuel Price	% of Avoid	Wtd Fuel
	Generating Facility	ECA Filing	Prod Sim	Ratio	Gen	Price Ratio
(7)	Kahului	724.13	749.46	0.97	0.05%	0.0005
(8)	Maalaea	1390.90	1317.49	1.06	99.95%	1.0552
(9)	HC&S	N/A	N/A	N/A	0.00%	0.0000
(10)	Total				100.00%	1.0557
	Off-Peak					
		Fuel Price (¢/MBTU)		Fuel Price	% of Avoid	Wtd Fuel
	Generating Facility	ECA Filing	Prod Sim	Ratio	Gen	Price Ratio
(11)	Kahului	724.13	749.46	0.97	16.49%	0.1593
(12)	Maalaea	1390.9	1317.49	1.06	83.51%	0.8816
(13)	HC&S	N/A	N/A	N/A	0.00%	0.0000
(14)	Total				100.00%	1.0410

MAUI ELECTRIC COMPANY, LTD.
MAUI DIVISION

ENERGY COST ADJUSTMENT FILING

Line			Line		
1	Effective Date September 1, 2005 Supersedes Factor of August 1, 2005				
	OIL-FIRED GENERATION COMPONENT			PURCHASED POWER COMPONENT	
				PURCHASED POWER PRICES, ¢/KWH	
	OIL PRICES, ¢/MBTU		17	HC&S - (Regular) - Off Peak	13.990
2	Industrial	724.13	18	- On Peak	15.330
3	Diesel	1,390.90	19	HC&S Emergency - Off Peak	13.990
			20	- On Peak	15.330
	OIL BTU MIX, %		21	HC&S-Unscheduled - Off Peak	13.990
4	Industrial	26.52%	22	- On Peak	15.330
5	Diesel	73.48%	23	Other (<100 kW)	
				PURCHASED POWER KWH MIX, %	
			24	HC&S - (Regular) - Off Peak	38.49%
			25	- On Peak	61.51%
			26	HC&S Emergency - Off Peak	0.00%
			27	- On Peak	0.00%
			28	HC&S-Unscheduled - Off Peak	0.00%
			29	- On Peak	0.00%
			30	Other (<100 kW)	0.00%
6	COMPOSITE GENERATION COST, ¢/MBTU, {Lines (2x4) + Lines (3x5)}	1,214.07			
7	% Input to System kWh Mix	94.38%	31	COMPOSITE COST OF PURCHASE ENERGY, ¢/KWH	14.814
8	Efficiency Factor, mbtu/kWh	0.011032	32	% Input to System kWh Mix	5.62%
9	WEIGHTED COMPOSITE GEN. COST, ¢/KWH, {Lines (6x7x8)}	12.64090	33	WEIGHTED COMP. PURCH. ENERGY COST, ¢/KWH, {Lines (31x32)}	0.83255
10	BASE GENERATION COST, ¢/MBTU	369.60			
11	Base % Input to System kWh Mix	91.79	34	BASE PURCHASED ENERGY COMPOSITE COST, ¢/KWH	5.028
12	Efficiency Factor, mbtu/kWh	0.011032	35	Base % Input to System kWh Mix	8.21
13	WEIGHTED BASE GEN. COST ¢/KWH, {Lines (10x11x12)}	3.74267	36	WEIGHTED BASE PURCH. ENERGY COST, ¢/KWH, Lines {34x35}	0.41280
14	COST LESS BASE { Line 9-13 }	8.89823	37	COST LESS BASE {LINE (33-36)}	0.41975
			38	Loss Factor	1.073
15	Multiplier to Include Rev. Tax Requirement	1.0975	39	Multiplier to Include Rev. Tax Requirement	1.0975
16	GENERATION FACTOR, ¢/KWH { Lines (14x15) }	9.76581	40	PURCHASED ENERGY FCTR, ¢/KWH {Lines (37x38x39)}	0.49430

Line	SYSTEM COMPOSITE CALCULATIONS	
41	FUEL AND PURCHASED ENERGY FACTOR, ¢/KWH {Lines 16+40}	10.260
42	ADJUSTMENT, ¢/KWH	0.000
43	ECA RECONCILIATION ADJUSTMENT, ¢/KWH	(0.126)
44	ENERGY COST ADJUSTMENT FACTOR, ¢/KWH	10.134

SUMMARY STATISTICS FOR MECO AVOIDED O&M
Docket No. 7310

OFF-PEAK					
UNIT TYPE	% Avoided MWH	Rate (ct/KWH)			
		Consum.	Maint.	Total	Net
Intermediate Steam (K1-2)	2.09%	0.141	0.000	0.141	0.003
Base Steam (K3-4)	14.46%	0.141	0.000	0.141	0.020
Peaking Diesel (X1,X2,M1-3)	1.24%	0.263	0.719	0.982	0.012
Intermediate Diesel (M4-M12)	69.56%	0.263	0.276	0.539	0.375
Base Diesel (M13)	3.70%	0.263	0.000	0.263	0.010
CT (M17,M19)	6.73%	0.067	0.423	0.490	0.033
DTCT (M141516)	2.21%	0.067	0.000	0.067	0.001
TOTAL	100.00%				0.454
ON-PEAK					
UNIT TYPE	% Avoided MWH	Rate (ct/KWH)			
		Consum.	Maint.	Total	Net
Intermediate Steam (K1-2)	0.05%	0.141	0.000	0.141	0.000
Base Steam (K3-4)	0.00%	0.100	0.000	0.100	0.000
Peaking Diesel (X1,X2,M1-3)	13.65%	0.263	0.705	0.968	0.132
Intermediate Diesel (M4-M12)	43.83%	0.263	0.151	0.414	0.181
Base Diesel (M13)	6.80%	0.263	0.000	0.263	0.018
CT (M17,M19)	35.68%	0.067	0.474	0.541	0.193
DTCT (M141516)	0.00%	0.000	0.000	0.000	0.000
TOTAL	100.00%				0.524
TOTAL					
UNIT TYPE	% Avoided MWH	Rate (ct/KWH)			
		Consum.	Maint.	Total	Net
Intermediate Steam (K1-2)	0.97%	0.141	0.000	0.141	0.001
Base Steam (K3-4)	6.55%	0.141	0.000	0.141	0.009
Peaking Diesel (X1,X2,M1-3)	8.03%	0.263	0.706	0.969	0.078
Intermediate Diesel (M4-M12)	55.48%	0.263	0.222	0.485	0.269
Base Diesel (M13)	5.40%	0.263	0.000	0.263	0.014
CT (M17,M19)	22.57%	0.067	0.467	0.534	0.121
DTCT (M141516)	1.00%	0.067	0.000	0.067	0.001
TOTAL	100.00%				0.493

Maui Electric Company, Ltd.
MAUI DIVISION
AVOIDED WORKING CASH CALCULATIONS

Avoided Working Cash Impact for Fuel and Purchased Eenrgy:

$$= \frac{\text{purchased energy payment lag days - fuel oil payment lag days}}{365}$$

$$\times \frac{\text{(rate of return on rate base) - (weighted cost of debt x composite income tax rate)}}{\text{(1 - composite income tax rate)}}$$

x avoided fuel cost

OR,

Avoided Working Cash Impact:
= avoided fuel working cash factor x avoided fuel cost

		On-Peak	Off-Peak
(1)	fuel oil payment lag days (a1)	33	33
(2)	purchased energy payment lag days (b)	35	35
(3)	rate of return on rate base (c)	8.830%	8.830%
(4)	weighted cost of debt (d)	2.88%	2.88%
(5)	composite income tax rate (e)	38.910%	38.910%
(6)	avoided fuel working cash factor	0.069%	0.069%
(7)	avoided fuel cost (¢/kwh)	14.327	12.061
(8)	avoided fuel working cash (¢/kwh)	0.010	0.008

Maui Electric Company, Ltd.
MAUI DIVISION
AVOIDED WORKING CASH CALCULATIONS

Avoided Working Cash Impact for O&M:

$$= \frac{\text{purchased energy payment lag days - O\&M payment lag days}}{365}$$

$$\times \frac{\text{(rate of return on rate base) - (weighted cost of debt x composite income tax rate)}}{\text{(1 - composite income tax rate)}}$$

$$\times \text{ avoided O\&M cost}$$

OR,

Avoided Working Cash Impact:

= avoided O&M working cash factor x avoided O&M cost

		On-Peak	Off-Peak
(1)	O&M payment lag days (a2)	31	31
(2)	purchased energy payment lag days (b)	35	35
(3)	rate of return on rate base (c)	8.830%	8.830%
(4)	weighted cost of debt (d)	2.88%	2.88%
(5)	composite income tax rate (e)	38.910%	38.910%
(6)	avoided O&M working cash factor	0.138%	0.138%
(7)	avoided O&M cost (¢/kwh)	0.524	0.454
(8)	avoided O&M working cash (¢/kwh)	0.001	0.001
(9)	total avoided working cash (¢/kwh) (Exhibit F page 5, line 8 plus Exhibit F page 6, Line 8)	0.011	0.009

References:

(a1) Docket No. 97-0346, MECO-RWP-1877, page 1 of 17

(a2) Docket No. 97-0346, MECO-RWP-1877, page 1 of 17, O&M Nonlabor payment lag days.

(b) Based on the specific payment provisions of each purchased power agreement. 35 days represents payment 20 days following the end of the month.

(c) Docket No. 97-0346, D&O No. 16922, page 50.

(d) Weighted Capital Cost on long term debt = 2.88%
Docket No. 97-0346, D&O No. 16922, page 50.

(e) Composite Income Tax Rate = 38.9098%
Docket No. 97-0346, D&O No. 16922, Exhibit A, page 4 of 4.

Maui Electric Company, Ltd.
MAUI DIVISION
AVOIDED FUEL INVENTORY CALCULATIONS

Avoided Fuel Invetory Impact:

= $\dfrac{\text{days of fuel invetory}}{365}$ x million btus (mbtus) avoided x $/mbtu

x $\dfrac{\text{(rate of return on rate base) - (weighted cost of debt x composite income tax rate)}}{\text{(1 - composite income tax rate)}}$

/ as-avaible QF energy

		On and Off-Peak	
		Industrial Fuel	Diesel Fuel
(1)	days of fuel inventory (a)	30	30
(2)	million btus fuel avoided (b)	117,747	1,115,570
(3)	fuel price ($/mbtu) (c)	2.2550	4.3996
(4)	rate of return on rate base (d)	8.830%	8.830%
(5)	weighted cost of debt (e)	2.88%	2.88%
(6)	compsite income tax rate (f)	38.910%	38.910%
(7)	as-available QF energy (MWH)	122,911	122,911
(8)	avoided fuel inventory (¢/kwh)	0.002	0.041
(9)	total avoided fuel inventory (¢/kwh)		0.043

See reference notes on following page.

References:

(a) Docket No. 97-0346 MECO-R-418 page 1 of 3.

(b) Production Simulations dated 07/25/05

(c) MECO Docket No. 99-0346, D&O 16922, pg 27. MECO-R-417 pgs 1-2.
Industrial: $14.2067 ÷ 6.3 = $2.2550/mbtu.
Diesel: $25.7814 ÷ 5.86 = $4.3996/mbtu.

(d) Docket No. 97-0346, D&O No. 16922, page 50.

(e) Weighted Capital Cost on long term debt = 2.88%
Docket No. 97-0346, D&O No. 16922, page 50.

(f) Composite Income Tax Rate = 38.9098%
Docket No. 97-0346, D&O No. 16922, Exhibit A, page 4 of 4.

Maui Electric Company, Ltd .
LANAI DIVISION
AVOIDED ENERGY COST RATES
ADJUSTED FOR FUEL PRICES EFFECTIVE July, August, September 2005

Line		On-Peak	Off-Peak	
(1)	Avoided Fuel Cost (Attachment 1)	19.789	14.786	¢/kwh
(2)	Avoided O&M Cost (Attachment 2)	1.827	0.942	¢/kwh
(3)	Avoided Working Cash (Attachment 3)	0.133	0.098	¢/kwh
(4)	Avoided Fuel Inventory (Attachment 4)	0.179	0.179	¢/kwh
(5)	Total Avoided Energy Cost Rates	21.928	16.005	¢/kwh
(6)	Total Weighted Avoided Energy Cost Rate* Off-Peak Avoided Cost Rate (Line 4 x Line 5)	19.4601		¢/kwh

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

Maui Electric Company, Ltd .
LANAI DIVISION
AVOIDED FUEL COST RATES
ADJUSTED FOR FUEL PRICES EFFECTIVE July, August, September 2005

Line	On-Peak Avoided Fuel Cost Rates		
(1)	On-Peak Avoided Heat Rate	12,764	btu/kwh
(2)	Composite Cost of Generation	1550.36	¢/mbtu
(3)	On-Peak Avoided Cost Rate (Line 1 x Line 2)	19.789	¢/kwh
	Off-Peak Avoided Fuel Cost Rates		
(4)	Off-Peak Avoided Heat Rate	9,537	btu/kwh
(5)	Composite Cost of Generation	1,550.36	¢/mbtu
(6)	Off-Peak Avoided Cost Rate (Line 4 x Line 5)	14.786	¢/kwh

MAUI ELECTRIC COMPANY, LTD.
LANAI DIVISION

ENERGY COST ADJUSTMENT FILING

Line				
1	Effective Date	July 1, 2005		
	Supersedes Factor of	June 1, 2005		

OIL-FIRED GENERATION COMPONENT

Line		
	OIL PRICES, ¢/MBTU	
2	Industrial	~~0.00~~
3	Off-Peak Avoided Cost Rate (Line 4 x Line 5)	1,550.36
	OIL BTU MIX, %	
4	Industrial	0.00
5	Diesel	100.00
6	COMPOSITE GENERATION COST, ¢/MBTU {Lines (2X4) + Lines (3X5)}	1,550.36
7	% Input to System kWh Mix	100.00%
8	Efficiency Factor, Mbtu/kWh	0.010678
9	WEIGHTED COMPOSITE GEN. COST, ¢/KWH {Lines (6X7X8)}	16.55474
10	BASE GENERATION COST, ¢/MBTU	773.27
11	Base % Input to System kWh Mix	100.00%
12	Efficiency Factor, Mbtu/kWh	0.010678
13	WEIGHTED BASE GEN. COST, ¢/KWH, {Lines (10X11X12)}	8.25698
14	COST LESS BASE {Lines (9-13)}	8.29776
15	Multiplier to Include Rev. Tax Requirement	1.0975
16	GENERATION FACTOR, ¢/KWH Lines (14X15)	9.10679

PURCHASED POWER COMPONENT

Line		
	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	0.00000
24	% Input to System kWh Mix	0.00%
25	WEIGHTED BASE PURCH ENERGY COST, ¢/KWH {Lines (23X24)}	0.00000
	BASE PURCHASED POWER	
26	COMPOSITE COST ¢/KWH	7.695
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)}	0.000
30	Loss Factor	1.073
31	Multiplier to Include Rev. Tax Requirement	1.0975
32	PURCHASED POWER FACTOR, ¢/KWH {Lines (29X30X31)}	0.00000

Line SYSTEM COMPOSITE CALCULATIONS

Line		
33	FUEL AND PURCHASED ENERGY FACTOR, ¢/KWH {Lines (16+32)}	9.107
34	ADJUSTMENT, ¢/KWH	0.000
35	ECA RECONCILIATION ADJUSTMENT, ¢/KWH	0.001
36	ENERGY COST ADJUSTMENT FACTOR, ¢/KWH	9.108

Maui Electric Company, Ltd .
LANAI DIVISION
DERIVATION OF THIRD QUARTER 2005
AVOIDED ENERGY COST PAYMENT RATES

Avoided Energy Rate - Over 100 kw

Line		On Peak	Off-Peak	Source
1	Heat Rate	12764.000 btu/kwh	9537.000 btu/kwh	Based on 2004 actual fuel consumption and kwh generation received from Jane Tanaka and Marco Paredes refer also to Lanai&Molokai_Aug 2005_R4
2	Fuel Price	1550.36 ¢/mbtu	1550.36 ¢/mbtu	From MECO (Lanai Division) Energy Cost Adjustment Filing, line 3, effective date of July 1, 2005.
	Off-Peak Avoided Cost Rate (Line 4 x Line 5)			
3	1 MMBTU / 1,000,000 BTU	1,000,000 btu/mmbtu	1,000,000 btu/mmbtu	
4	Unadjusted Payment Rate ((Line 1 X Line 2) / Line 3)	19.79 ¢/kwh	14.79 ¢/kwh	
5	O&M Adjustment	1.827 ¢/kwh	0.942 ¢/kwh	Based on MECO 1999 TY Rate Case Variable O&M Costs escalated by actual Honolulu CPI-U rates from 1999-2005 From Lanai&Molokai_Aug 2005_R6 sheet= Lanai Production Cost
6	BASE Avoided Energy Payment Rate	21.62 ¢/kwh	15.73 ¢/kwh	

Maui Electric Company, Ltd.
LANAI DIVISION
AVOIDED WORKING CASH CALCULATIONS

Avoided Working Cash Impact for Fuel and Purchased Energy:

$$= \frac{\text{purchased energy payment lag days - fuel oil payment lag days}}{365.000}$$

$$\times \frac{\text{(rate of return on rate base) - (weighted cost of debt x composite income tax rate)}}{\text{(1 - composite income tax rate)}}$$

x avoided fuel cost

OR, Off-Peak Avoided Cost Rate (Line 4 x Line 5)

Avoided Working Cash Impact:

= avoided fuel working cash factor x avoided fuel cost

		On-Peak	Off-Peak
(1)	fuel oil payment lag days (a1)	16	16
(2)	purchased energy payment lag days (b)	35	35
(3)	rate of return on rate base (c)	8.830%	8.830%
(4)	weighted cost of debt (d)	2.880%	2.880%
(5)	composite income tax rate (e)	38.910%	38.910%
(6)	avoided fuel working cash factor	0.657%	0.657%
(7)	avoided fuel cost (¢/kwh)	19.789	14.786
(8)	avoided fuel working cash (¢/kwh)	0.130	0.097

See reference notes on Exhibit G Page 7.

Maui Electric Company, Ltd.
LANAI DIVISION
AVOIDED WORKING CASH CALCULATIONS

Avoided Working Cash Impact for O&M:

$$= \frac{\text{purchased energy payment lag days - O\&M payment lag days}}{365}$$

$$\times \frac{\text{(rate of return on rate base) - (weighted cost of debt x composite income tax rate)}}{\text{(1 - composite income tax rate)}}$$

x avoided O&M cost

OR,

Off-Peak Avoided Cost Rate (Line 4 x Line 5)

Avoided Working Cash Impact:

= avoided O&M working cash factor x avoided O&M cost

		On-Peak	Off-Peak
(1)	O&M payment lag days (a2)	31	31
(2)	purchased energy payment lag days (b)	35	35
(3)	rate of return on rate base (c)	8.830%	8.830%
(4)	weighted cost of debt (d)	2.880%	2.880%
(5)	composite income tax rate (e)	38.910%	38.910%
(6)	avoided O&M working cash factor	0.138%	0.138%
(7)	avoided O&M cost (¢/kwh)	1.8270	0.9420
(8)	avoided O&M working cash (¢/kwh)	0.003	0.001
(9)	total avoided working cash (¢/kwh) (Exhibit G page 5, line 8 plus Exhibit G page 6, Line 8)	0.1330	0.0980

References:

(a1) Docket No. 97-0346, MECO-RWP-1877, page 2 of 17.

(a2) Docket No. 97-0346, MECO-RWP-1877, page 2 of 1,
O&M Nonlabor payment lag days.

(b) Based on the specific payment provisions of each purchased power agreement. 35 days represents payment 20 days following the end of the month.

(c) Docket No. 97-0346, D&O No. 16922, page 50

(d) Weighted Capital Cost on long term debt = 2.88%
Off-Peak Avoided Cost Rate (Line 4 x Line 5)

(e) Composite Income Tax Rate = 38.9098%
Docket No. 97-0346, D&O No. 16922, Exhibit A, page 4 of 4

Maui Electric Company, Ltd.
LANAI DIVISION
AVOIDED FUEL INVENTORY CALCULATIONS

Avoided Fuel Invetory Impact:

$$= \frac{\text{days of fuel invetory}}{365} \times \text{million btus (mbtus) avoided} \times \$/\text{mbtu}$$

$$\times \frac{(\text{rate of return on rate base}) - (\text{weighted cost of debt} \times \text{composite income tax rate})}{(1 - \text{composite income tax rate})}$$

/ as-avaible QF energy

Off-Peak Avoided Cost Rate (Line 4 x Line 5)

		On and Off-Peak Industrial Fuel	Diesel Fuel
(1)	days of fuel inventory (a)	N/A	30
(2)	million btus fuel avoided (b)		195,357
(3)	fuel price ($/mbtu) (c)		7.7327
(4)	rate of return on rate base (d)	8.830%	8.830%
(5)	weighted cost of debt (e)	2.880%	2.880%
(6)	composite income tax rate (f)	38.910%	38.910%
(7)	as-available QF energy (MWH)	8,760	8,760
(8)	avoided fuel inventory (¢/kwh)		0.179
(9)	total avoided fuel inventory (¢/kwh)		0.179

See reference notes on following page.

References:

(a) Docket No. 97-0346 MECO-R-418 page 2 of 3

(b) Based on 2004 actual fuel consumtion and kwh generation.
On-peak system heat rate (LL1-LL6) = 12,764 btu/kwh

12,764 btu/kwh X 8,760 mwh =	111,813	mbtu

Off-peak system heat rate (LL7-LL8) = 9,537 btu/kwh

9,537 btu/kwh X 8,760 mwh =	83,544	mbtu
Total=	195,357	

(c) MECO Docket No. 97-0346, D&O 16922, pg 27. MECO-R-417, pg 4.
$45.3135/bbl ÷ 5.86 = $7.7327/mbtu.

(d) Off-Peak Avoided Cost Rate (Line 4 x Line 5)

(e) Weighted Capital Cost on long term debt = 2.88%
Docket No. 97-0346, D&O No. 16922, page 50

(f) Composite Income Tax Rate = 38.9098%
Docket No. 97-0346, D&O No. 16922, Exhibit A, page 4 of 4

Maui Electric Company, Ltd .
MOLOKAI DIVISION
AVOIDED ENERGY COST RATES
ADJUSTED FOR FUEL PRICES EFFECTIVE July, August, September 2005

Line		On-Peak	Off-Peak	
(1)	Avoided Fuel Cost (Attachment 1)	14.857	13.129	¢/kwh
(2)	Avoided O&M Cost (Attachment 2)	0.955	0.933	¢/kwh
(3)	Avoided Working Cash (Attachment 3)	-0.050	-0.044	¢/kwh
(4)	Avoided Fuel Inventory (Attachment 4)	0.099	0.099	¢/kwh
(5)	Total Avoided Energy Cost Rates	15.861	14.117	¢/kwh
(6)	Total Weighted Avoided Energy Cost Rate*	15.1343		¢/kwh

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

Maui Electric Company, Ltd .
MOLOKAI DIVISION
AVOIDED FUEL COST RATES
ADJUSTED FOR FUEL PRICES EFFECTIVE July, August, September 2005

Line	On-Peak Avoided Fuel Cost Rates		
(1)	On-Peak Avoided Heat Rate	10,873	btu/kwh
(2)	Composite Cost of Generation	1,366.44	¢/mbtu
(3)	On-Peak Avoided Cost Rate (Line 1 x Line 2)	14.857	¢/kwh
	Off-Peak Avoided Fuel Cost Rates		
(4)	Off-Peak Avoided Heat Rate	9,608	btu/kwh
(5)	Composite Cost of Generation	1,366.44	¢/mbtu
(6)	Off-Peak Avoided Cost Rate (Line 4 x Line 6)	13.129	¢/kwh

MAUI ELECTRIC COMPANY, LTD.
MOLOKAI DIVISION

ENERGY COST ADJUSTMENT FILING

Line			
1	Effective Date	July 1, 2005	
	Supersedes Factor of	June 1, 2005	
	OIL-FIRED GENERATION COMPONENT		
	OIL PRICES, ¢/MBTU		
2	Industrial		~~0.00~~
3	Diesel		1,366.44
	OIL BTU MIX, %		
4	Industrial		0.00%
5	Diesel		100.00%
6	COMPOSITE GENERATION COST, ¢/MBTU {Line(2X4)+Line(3X5)}		1,366.44
7	% Input to System kWh Mix		100.0%
8	Efficiency Factor, mbtu/kWh		0.010522
9	WEIGHTED COMPOSITE GEN. COST, ¢/KWH {LINES (6X7X8)}		14.37768
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)}		9.45822
15	Multiplier to include Rev. Tax Requirement		1.09750
16	GENERATION FACTOR, ¢/KWH LINES (14X15)		10.38040

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)}	10.38040
34	ADJUSTMENT, ¢/KWH	0.000
35	ECA RECONCILIATION ADJUSTMENT, ¢/KWH	0.002
36	ENERGY COST ADJUSTMENT FACTOR, ¢/KWH	10.382

Maui Electric Company, Ltd .
MOLOKAI DIVISION
DERIVATION OF THIRD QUARTER 2005
AVOIDED ENERGY COST PAYMENT RATES

Avoided Energy Rate - Over 100 kw

Line		On Peak	Off-Peak	Source
1	Heat Rate	10,873 btu/kwh	9,608 btu/kwh	Based on 2004 actual fuel consumption and kwh generation received from Jane Tanaka and Marco Paredes refer also to Lanai&Molokai_Aug 2005_R4
2	Fuel Price	1,366.44 ¢/mbtu	1,366.44 ¢/mbtu	From MECO (Molokai Division) Energy Cost Adjustment Filing, line 3, effective date of July 1, 2005.
3	1 MMBTU / 1,000,000 BTU	1,000,000 btu/mmbtu	1,000,000 btu/mmbtu	
4	Unadjusted Payment Rate ((Line 1 X Line 2) / Line 3)	14.86 ¢/kwh	13.13 ¢/kwh	
5	O&M Adjustment	0.955 ¢/kwh	0.933 ¢/kwh	Based on MECO 1999 TY Rate Case Variable O&M Costs escalated by actual Honolulu CPI-U from 1999-2005 From Lanai&Molokai_Aug 2005_R6 sheet= Molokai Production Cos
6	BASE Avoided Energy Payment Rate	15.81 ¢/kwh	14.06 ¢/kwh	

Maui Electric Company, Ltd.
MOLOKAI DIVISION
AVOIDED WORKING CASH CALCULATIONS

Avoided Working Cash Impact for Fuel and Purchased Energy:

$$= \frac{\text{purchased energy payment lag days - fuel oil payment lag days}}{365}$$

$$\times \frac{\text{(rate of return on rate base) - (weighted cost of debt x composite income tax rate)}}{\text{(1 - composite income tax rate)}}$$

x avoided fuel cost

OR,

Avoided Working Cash Impact:
= avoided fuel working cash factor x avoided fuel cost

		On-Peak	Off-Peak
(1)	fuel oil payment lag days (a1)	45	45
(2)	purchased energy payment lag days (b)	35	35
(3)	rate of return on rate base (c)	8.830%	8.830%
(4)	weighted cost of debt (d)	2.880%	2.880%
(5)	composite income tax rate (e)	38.910%	38.910%
(6)	avoided fuel working cash factor	-0.346%	-0.346%
(7)	avoided fuel cost (¢/kwh)	14.857	13.129
(8)	avoided fuel working cash (¢/kwh)	-0.051	-0.045

See reference notes on Exhibit H Page 7.

Maui Electric Company, Ltd.
MOLOKAI DIVISION
AVOIDED WORKING CASH CALCULATIONS

Avoided Working Cash Impact for O&M:

$$= \frac{\text{purchased energy payment lag days - O\&M payment lag days}}{365}$$

$$\times \frac{\text{(rate of return on rate base) - (weighted cost of debt x composite income tax rate)}}{\text{(1 - composite income tax rate)}}$$

$$\times \text{ avoided O\&M cost}$$

OR,

Avoided Working Cash Impact:

= avoided O&M working cash factor x avoided O&M cost

		On-Peak	Off-Peak
(1)	O&M payment lag days (a2)	31	31
(2)	purchased energy payment lag days (b)	35	35
(3)	rate of return on rate base (c)	8.830%	8.830%
(4)	weighted cost of debt (d)	2.880%	2.880%
(5)	composite income tax rate (e)	38.910%	38.910%
(6)	avoided O&M working cash factor	0.138%	0.138%
(7)	avoided O&M cost (¢/kwh)	0.9550	0.9330
(8)	avoided O&M working cash (¢/kwh)	0.001	0.001
(9)	total avoided working cash (¢/kwh) (Exhibit G page 5, line 8 plus Exhibit G page 6, Line 8)	-0.050	-0.044

References:

(a1) Docket No. 97-0346, MECO-RWP-1877, page 3 of 17

(a2) Docket No. 97-0346, MECO-RWP-1877, page 3 of 17,
O&M Nonlabor payment lag days.

(b) Based on the specific payment provisions of each purchased power agreement. 35 days represents payment 20 days following the end of the month.

(c) Docket No. 97-0346, D&O No. 16922, page 50

(d) Weighted Capital Cost on long term debt = 2.88%
Docket No. 97-0346, D&O No. 16922, page 50

(e) Composite Income Tax Rate = 38.9098%
Docket No. 97-0346, D&O No. 16922, Exhibit A, page 4 of 4

Maui Electric Company, Ltd.
MOLOKAI DIVISION
AVOIDED FUEL INVENTORY CALCULATIONS

Avoided Fuel Invetory Impact:

$$= \frac{\text{days of fuel invetory}}{365} \times \text{million btus (mbtus) avoided} \times \$/\text{mbtu}$$

$$\times \frac{\text{(rate of return on rate base) - (weighted cost of debt x composite income tax rate)}}{\text{(1 - composite income tax rate)}}$$

$$/ \quad \text{as-availble QF energy}$$

		On and Off-Peak	
		Industrial Fuel	Diesel Fuel
(1)	days of fuel inventory (a)	N/A	30
(2)	million btus fuel avoided (b)		179,414
(3)	fuel price ($/mbtu) (c)		4.6754
(4)	rate of return on rate base (d)	8.830%	8.830%
(5)	weighted cost of debt (e)	2.880%	2.880%
(6)	composite income tax rate (f)	38.910%	38.910%
(7)	as-available QF energy (MWH)	8,760	8,760
(8)	avoided fuel inventory (¢/kwh)		0.099
(9)	total avoided fuel inventory (¢/kwh)		0.099

See reference notes on Exhibit page 9 of 9.

References:

(a) Docket No. 97-0346 MECO-R-418 page 3 of 3

(b) Based on 2004 actual fuel consumtion and kwh generation.
On-peak system heat rate (P1-P6) = 10,873 btu/kwh
10,873 btu/kwh X 8,760 mwh = 95,247 mbtu
Off-peak system heat rate (P7-P9) = 9,608 btu/kwh
9,608 btu/kwh X 8,760 mwh = 84,166 mbtu
Total= 179,414

(c) MECO Docket No. 97-0346, D&O 16922, pg 27. MECO-R-417 pg 5.
$27.3979/bbl ÷ 5.86 = $4.6754/mbtu

(d) Docket No. 97-0346, D&O No. 16922, page 50

(e) Weighted Capital Cost on long term debt = 2.88%
Docket No. 97-0346, D&O No. 16922, page 50

(f) Composite Income Tax Rate = 38.9098%
Docket No. 97-0346, D&O No. 16922, Exhibit A, page 4 of 4

Avoided Fuel Cost Rates Update Schedule

Reference	On-Peak Avoided Fuel Cost Rates Update Schedule	Update Interval
(1)	On-Peak Avoided Cost Rate	Annual
(2)	On-Peak Adjustment Factor	Monthly
	Off-Peak Avoided Fuel Cost Rates Update Schedule	
(4)	Off-Peak Avoided Cost Rate	Annual
(5)	Off-Peak Adjustment Factor	Monthly
	Adjustment Factors	
(7) and thereafter	Fuel Price ECA Filing	Monthly
	Fuel Price Production Simulation	Annual
	% of Avoided Generation	Annual

HECO Avoided O&M Rates

	Consumables		Maintenance		Comments
	Rate	Units	Rate	Units	
Honolulu Station					
Steam Units		¢/kwh			
H8	0.025		0.000		See Note 1
H9	0.025		0.000		See Note 1
Kahe Station					
Steam Units		¢/kwh			
K1	0.025		0.000		See Note 1
K2	0.025		0.000		See Note 1
K3	0.025		0.000		See Note 1
K4	0.025		0.000		See Note 1
K5	0.025		0.000		See Note 1
K6	0.025		0.000		See Note 1
Waiau Station					
Steam Units		¢/kwh			
W3	0.025		0.000		See Note 1
W4	0.025		0.000		See Note 1
W5	0.025		0.000		See Note 1
W6	0.025		0.000		See Note 1
W7	0.025		0.000		See Note 1
W8	0.025		0.000		See Note 1
CT Units				$/Hr	
W9	0.000		75.734		See Note 1
W10	0.000		75.734		See Note 1
IPP		¢/kwh			
AES	0.000		0.000		HECO Purchase Power Contracts (note 2)
KPLP	0.000		0.000		HECO Purchase Power Contracts
H-POWER	0.000		0.000		HECO Purchase Power Contracts

Notes:

1. HECO unit variable O&M rates based on the 3/4/94 stipulation from Docket 7310 escalated to 2005$ by the Consumer Price Index - Urban for Honolulu
2. AES variable O&M accounted for in the ABC coefficients

HECO Avoided Off-Peak O&M based on 1 MW Simulation

Off-Peak	MWH				Hours of operation			O&M Rates		Avoided O&M Costs, $		
	Base	QF in	Diff.	% of Total	Base	QF in	Diff.	Consum.	Maint.	Consum.	Maint.	Total
Honolulu								(¢/kwh)	($/Hr)			
Steam Units												
Honolulu 8	12,798	12,816	-18	-0.49%	561.5	562.4	-0.9	0.025	0.00	-5	0	-5
Honolulu 9	7,101	7,089	12	0.33%	305.1	305.1	0.0	0.025	0.00	3	0	3
Total	19,899	19,905	-6	-0.16%	866.6	867.5	-0.9			-2	0	-2
Kahe												
Steam Units												
Kahe 1	112,490	112,257	233	6.38%	2,883.6	2,883.6	0.0	0.025	0.00	58	0	58
Kahe 2	138,612	138,173	439	12.03%	3,534.3	3,534.3	0.0	0.025	0.00	110	0	110
Kahe 3	184,874	184,406	468	12.82%	3,258.9	3,258.9	0.0	0.025	0.00	117	0	117
Kahe 4	136,329	135,973	356	9.75%	2,649.4	2,649.4	0.0	0.025	0.00	89	0	89
Kahe 5	334,709	333,982	727	19.92%	3,513.7	3,513.7	0.0	0.025	0.00	182	0	182
Kahe 6	186,160	185,765	395	10.82%	2,869.5	2,869.5	0.0	0.025	0.00	99	0	99
Total	1,093,174	1,090,556	2,618	71.73%	18,709.4	18,709.4	0.0			655	0	655
Waiau												
Steam Units												
Waiau 3	301	301	0	0.00%	10.0	10.0	0.0	0.025	0.00	0	0	0
Waiau 4	622	581	41	1.12%	27.7	25.9	1.8	0.025	0.00	10	0	10
Waiau 5	2,515	2,493	22	0.60%	109.3	108.3	1.0	0.025	0.00	6	0	6
Waiau 6	1,260	1,191	69	1.89%	55.4	52.4	3.0	0.025	0.00	17	0	17
Waiau 7	123,337	123,148	189	5.18%	3,388.9	3,388.9	0.0	0.025	0.00	47	0	47
Waiau 8	151,780	151,516	264	7.23%	3,408.1	3,408.1	0.0	0.025	0.00	66	0	66
Total	279,815	279,230	585	16.03%	6,999.4	6,993.6	5.8			146	0	146
CT Units												
Waiau 9	0	0	0	0.00%	0.0	0.0	0.0	0.000	75.734	0	0	0
Waiau 10	0	0	0	0.00%	0.0	0.0	0.0	0.000	75.734	0	0	0
Total	0	0	0	0.00%	0.0	0.0	0.0			0	0	0
Total	279,815	279,230	585	16.03%	6,999.4	6,993.6	5.8			146	0	146
IPP												
AES	637,932	637,932	0	0.00%	3,613.5	3,613.5	0.0	0.000	0.00	0	0	0
KPLP	583,204	582,751	453	12.41%	8,201.0	8,201.0	0.0	0.000	0.00	0	0	0
H-POWER	141,632	141,632	0	0.00%	3,550.0	3,550.0	0.0	0.000	0.00	0	0	0
Total	1,362,768	1,362,315	453	12.41%	15,364.5	15,364.5	0.0			0	0	0
TOTAL	2,755,656	2,752,006	3,650	100.00%	41,939.9	41,935.0	4.9			799	0	799

Total Avoided Cost, ¢/kwh	0.022

HECO Avoided Off-Peak O&M based on 1 MW Simulation

SUMMARY STATISTICS

UNIT TYPE	% Avoided MWH	Rate (¢/kwh) Consum.	Maint.	Total	Net
HECO					
Steam	87.60%	0.025	0.000	0.025	0.022
CTs	0.00%	0.000	0.000	0.000	0.000
AES	0.00%	0.000	0.000	0.000	0.000
KPLP	12.40%	0.000	0.000	0.000	0.000
H-POWER	0.00%	0.000	0.000	0.000	0.000
TOTAL	100.00%				0.022

Note:
Unit Rates = Total O&M $/Avoided Unit MWH
Net Rates = Unit Rates * % Avoided MWH

HECO Avoided On-Peak O&M based on 1 MW Simulation

On-Peak	MWH				Hours of operation			O&M Rates		Avoided O&M Costs, $		
	Base	QF in	Diff.	% of Total	Base	QF in	Diff.	Consum. (¢/kwh)	Maint. ($/Hr)	Consum.	Maint.	Total
Honolulu												
Steam Units												
Honolulu 8	109,871	109,741	130	2.55%	4,435.1	4,434.9	0.2	0.025	0.000	33	0	33
Honolulu 9	114,657	114,345	312	6.12%	4,108.7	4,108.6	0.1	0.025	0.000	78	0	78
Total	224,528	224,086	442	8.66%	8,543.8	8,543.5	0.3			111	0	111
Kahe												
Steam Units												
Kahe 1	239,328	238,776	552	10.82%	4,037.1	4,037.1	0.0	0.025	0.000	138	0	138
Kahe 2	389,181	388,518	663	13.00%	4,948.1	4,948.1	0.0	0.025	0.000	166	0	166
Kahe 3	394,808	394,640	168	3.29%	4,562.4	4,562.4	0.0	0.025	0.000	42	0	42
Kahe 4	303,410	302,968	442	8.66%	3,709.1	3,709.1	0.0	0.025	0.000	111	0	111
Kahe 5	660,357	660,410	-53	-1.04%	4,919.1	4,919.1	0.0	0.025	0.000	-13	0	-13
Kahe 6	445,270	444,130	1140	22.35%	4,017.3	4,017.3	0.0	0.025	0.000	285	0	285
Total	2,432,354	2,429,442	2,912	57.09%	26,193.1	26,193.1	0.0			729	0	729
Waiau												
Steam Units												
Waiau 3	22,962	22,775	187	3.67%	746.1	740.4	5.7	0.025	0.000	47	0	47
Waiau 4	25,787	25,741	46	0.90%	1,113.9	1,112.8	1.1	0.025	0.000	12	0	12
Waiau 5	79,055	79,088	-33	-0.65%	3,240.7	3,246.2	-5.5	0.025	0.000	-8	0	-8
Waiau 6	55,021	54,728	293	5.74%	2,305.3	2,295.5	9.8	0.025	0.000	73	0	73
Waiau 7	261,725	261,338	387	7.59%	4,744.4	4,744.4	0.0	0.025	0.000	97	0	97
Waiau 8	327,285	326,462	823	16.13%	4,771.4	4,771.4	0.0	0.025	0.000	206	0	206
Total	771,835	770,132	1703	33.39%	16,921.8	16,910.7	11.1			427	0	427
CT Units												
Waiau 9	1,634	1,615	19	0.37%	103.6	102.5	1.1	0.000	75.734	0	83	83
Waiau 10	4,852	4,827	25	0.49%	313.0	311.8	1.2	0.000	75.734	0	91	91
Total	6,486	6,442	44	0.86%	416.6	414.3	2.3			0	174	174
Total	778,321	776,574	1747	34.25%	17,338.4	17,325.0	13.4			427	174	601
IPP												
AES	893,117	893,117	0	0.00%	5,058.9	5,058.9	0.0	0.000	0.000	0	0	0
KPLP	965,380	965,380	0	0.00%	13,685.7	13,685.7	0.0	0.000	0.000	0	0	0
H-POWER	198,284	198,284	0	0.00%	4,970.0	4,970.0	0.0	0.000	0.000	0	0	0
Total	2,056,781	2,056,781	0	0.00%	23,714.6	23,714.6	0.0			0	0	0
TOTAL	5,491,984	5,486,883	5,101	100.00%	75,789.9	75,776.2	13.7			1,267	174	1,441

Total Avoided Cost, ¢/kwh	0.028

HECO Avoided On-Peak O&M based on 1 MW Simulation

SUMMARY STATISTICS

UNIT TYPE	% Avoided MWH	Rate (¢/kwh)			
		Consum.	Maint.	Total	Net
HECO					
Steam	99.14%	0.025	0.000	0.025	0.025
CTs	0.86%	0.000	0.395	0.395	0.003
AES	0.00%	0.000	0.000	0.000	0.000
KPLP	0.00%	0.000	0.000	0.000	0.000
H-POWER	0.00%	0.000	0.000	0.000	0.000
TOTAL	100.00%				0.028

Note:
Unit Rates = Total O&M $/Avoided Unit MWH
Net Rates = Unit Rates * % Avoided MWH

HECO Avoided Total O&M based on 1 MW Simulation

Total	MWH				Hours of operation			O&M Rates		Avoided O&M Costs, $		
	Base	QF in	Diff.	% of Total	Base	QF in	Diff.	Consum.	Maint.	Consum.	Maint.	Total
Honolulu								(¢/kwh)	($/Hr)			
Steam Units												
Honolulu 8	122,669	122,557	112	2.20%	4,996.6	4,997.3	-0.7	0.025	0.000	28	0	28
Honolulu 9	121,758	121,434	324	6.35%	4,413.8	4,413.7	0.1	0.025	0.000	81	0	81
Total	244,427	243,991	436	8.55%	9,410.4	9,411.0	-0.6			109	0	109
Kahe												
Steam Units												
Kahe 1	351,818	351,033	785	15.39%	6,920.7	6,920.7	0.0	0.025	0.000	196	0	196
Kahe 2	527,793	526,691	1102	21.60%	8,482.4	8,482.4	0.0	0.025	0.000	276	0	276
Kahe 3	579,682	579,046	636	12.47%	7,821.3	7,821.3	0.0	0.025	0.000	159	0	159
Kahe 4	439,739	438,941	798	15.64%	6,358.5	6,358.5	0.0	0.025	0.000	200	0	200
Kahe 5	995,066	994,392	674	13.21%	8,432.8	8,432.8	0.0	0.025	0.000	169	0	169
Kahe 6	631,430	629,895	1535	30.09%	6,886.8	6,886.8	0.0	0.025	0.000	384	0	384
Total	3,525,528	3,519,998	5,530	108.41%	44,902.5	44,902.5	0.0			1,384	0	1,384
Waiau												
Steam Units												
Waiau 3	23,263	23,076	187	3.67%	756.1	750.4	5.7	0.025	0.000	47	0	47
Waiau 4	26,409	26,322	87	1.71%	1,141.6	1,138.7	2.9	0.025	0.000	22	0	22
Waiau 5	81,570	81,581	-11	-0.22%	3,350.0	3,354.5	-4.5	0.025	0.000	-3	0	-3
Waiau 6	56,281	55,919	362	7.10%	2,360.7	2,347.9	12.8	0.025	0.000	91	0	91
Waiau 7	385,062	384,486	576	11.29%	8,133.3	8,133.3	0.0	0.025	0.000	144	0	144
Waiau 8	479,065	477,978	1087	21.31%	8,179.5	8,179.5	0.0	0.025	0.000	272	0	272
Total	1,051,650	1,049,362	2288	44.85%	23,921.2	23,904.3	16.9			573	0	573
CT Units												
Waiau 9	1,634	1,615	19	0.37%	103.6	102.5	1.1	0.000	75.734	0	83	83
Waiau 10	4,852	4,827	25	0.49%	313.0	311.8	1.2	0.000	75.734	0	91	91
Total	6,486	6,442	44	0.86%	416.6	414.3	2.3			0	174	174
Total	1,058,136	1,055,804	2332	45.72%	24,337.8	24,318.6	19.2			573	174	747
IPP												
AES	1,531,049	1,531,049	0	0.00%	8,672.4	8,672.4	0.0	0.000	0.000	0	0	0
KPLP	1,548,584	1,548,131	453	8.88%	21,886.7	21,886.7	0.0	0.000	0.000	0	0	0
H-POWER	339,916	339,916	0	0.00%	8,520.0	8,520.0	0.0	0.000	0.000	0	0	0
Total	3,419,549	3,419,096	453	8.88%	39,079.1	39,079.1	0.0			0	0	0
TOTAL	8,247,640	8,238,889	8,751	171.55%	117,729.8	117,711.2	18.6			2,066	174	2,240

Total Avoided Cost, ¢/kwh	0.026

HECO Avoided Total O&M based on 1 MW Simulation

SUMMARY STATISTICS

UNIT TYPE	% Avoided MWH	Rate (¢/kwh)			
		Consum.	Maint.	Total	Net
HECO					
Steam	94.32%	0.025	0.000	0.025	0.024
CTs	0.50%	0.000	0.395	0.395	0.002
AES	0.00%	0.000	0.000	0.000	0.000
KPLP	5.18%	0.000	0.000	0.000	0.000
H-POWER	0.00%	0.000	0.000	0.000	0.000
TOTAL	100.00%				0.026

Note:
Unit Rates = Total O&M $/Avoided Unit MWH
Net Rates = Unit Rates * % Avoided MWH

HELCO Avoided O and M Rate

	Consumables		Maintenance		Comments
	Rate	Units	Rate	Units	
Hill Power Plant		(¢/kwh)		$/Hr	
H5	0.083		62.859		Note 1.
H6	0.083		62.859		Note 1.
Puna		(¢/kwh)		$/Hr	
Puna	0.137		83.398		Note 1.
CT-3	0.054		118.729		Note 1.
Shipman		(¢/kwh)		$/Hr	
3	0.191		62.174		Note 1.
4	0.191		62.174		Note 1.
Waimea		(¢/kwh)		$/Hr	
12	0.098		18.382		Note 1.
13	0.098		18.382		Note 1.
14	0.098		18.382		Note 1.
Keahole		(¢/kwh)		$/Hr	
21	0.060		19.306		Note 1.
22	0.060		19.306		Note 1.
23	0.060		19.306		Note 1.
CT-2	0.297		95.720		Note 1.
CT-4	0.087		95.312		Based on actual data since CT-4 installation 5/26/04
CT-5	0.087		95.312		Based on actual data since CT-5 installation 6/30/04
Kanoelehua		(¢/kwh)		$/Hr	
11	0.094		20.286		Note 1.
15	0.094		20.286		Note 1.
16	0.094		20.286		Note 1.
17	0.094		20.286		Note 1.
Hilo CT-1	0.032		761.766		Based on 5 year average

Notes:
1. Based on HELCO TY2000 Rate Case Docket No. 99-0207 escalated to 2005$ by Consumer Price Index-Urban for Honolulu

HELCO Avoided Off-Peak O and M based on HELCO Simulation

OFF-PEAK	MWH			Hours of operation			O&M Rates		Avoided O&M Costs, $		
	Base	QF IN	Diff.	Base	QF IN	Diff.	Consum.	Maint.	Consum.	Maint.	Total
Steam Units							(¢/kwh)	($/hr)			
Shipman 3	84	82	2	14	14	0	0.191	62.174	4	0	4
Shipman 4	37	35	2	7	7	0	0.191	62.174	4	19	22
Hill 5	25,783	25,263	520	2,918	2,918	0	0.083	62.859	431	0	431
Hill 6	60,796	60,380	416	3,317	3,317	0	0.083	62.859	345	0	345
Puna	44,126	43,170	956	3,156	3,156	0	0.137	83.398	1,305	0	1,305
Diesel Units											
Waim EMD	601	541	60	288	257	31	0.098	18.382	59	0	59
D12	0	0	0	82	75	7	0.098	18.382	0	127	127
D13	0	0	0	122	107	14	0.098	18.382	0	263	263
D14	0	0	0	85	75	10	0.098	18.382	0	182	182
Kanoe EMD	1,093	967	126	590	524	66	0.094	20.286	118	0	118
D11	0	0	0	325	295	30	0.094	20.286	0	603	603
D15	0	0	0	87	76	12	0.094	20.286	0	233	233
D16	0	0	0	91	79	12	0.094	20.286	0	250	250
D17	0	0	0	87	75	12	0.094	20.286	0	250	250
Keah EMD	116	114	2	53	51	2	0.060	19.306	1	0	1
D21	0	0	0	14	13	1	0.060	19.306	0	15	15
D22	0	0	0	23	22	1	0.060	19.306	0	12	12
D23	0	0	0	17	16	1	0.060	19.306	0	12	12
Dispersed	17	12	5	22	16	5	0.566	0.000	28	0	28
D24	0	0	0	6	5	1	0.566	0.000	0	0	0
D25	0	0	0	5	4	1	0.566	0.000	0	0	0
D26	0	0	0	4	3	1	0.566	0.000	0	0	0
D27	0	0	0	6	4	1	0.566	0.000	0	0	0
CT-1	115	93	22	18	15	3	0.032	761.766	7	2,209	2,216
CT-2	38	65	-27	5	7	-2	0.297	95.720	-80	-153	-233
CT-3	1,522	1,167	355	134	107	27	0.054	118.729	192	3,182	3,374
CT-4	16,676	15,575	1,101	1,154	1,090	64	0.087	95.312	959	6,138	7,098
CT-5	9,301	7,841	1,460	642	547	95	0.087	95.312	1,272	9,026	10,298
As-Available											
Lalamilo	784	784	0	0	0	0	0.000	0.000	0	0	0
HELCO Hydro	2,584	2,584	0	3,650	3,650	0	0.000	0.000	0	0	0

HELCO Avoided Off-Peak O and M based on HELCO Simulation

	MWH			Hours of operation			O&M Rates		Avoided O&M Costs, $		
	Base	QF IN	Diff.	Base	QF IN	Diff.	Consum.	Maint.	Consum.	Maint.	Total
IPP							(¢/kwh)	($/hr)			
HEP	173,187	161,833	11,354	3,476	3,391	86	1.080	241.748	12,267	20,669	32,936
HCPC	0	0	0	0	0	0	0.000	0.000	0	0	0
PGV	56,355	56,355	0	2,562	2,562	0	0.000	0.000	0	0	0
TOTAL	393,215	376,861	16,354	22,955	22,474	481			16,913	43,035	59,948

Total Avoided Cost, cents/kwh	0.367

SUMMARY STATISTICS

OFF-PEAK					
UNIT TYPE	% Avoided MWH	Rate (¢/kwh)			
		Consum.	Maint.	Total	Net
Base Steam	5.72%	0.083	0.000	0.083	0.005
Interm. Steam					
Shipman	0.02%	0.191	0.466	0.657	0.000
Puna	5.85%	0.137	0.000	0.137	0.008
CTs	17.80%	0.081	0.701	0.782	0.139
Diesel Units	1.18%	0.107	1.008	1.115	0.013
HEP	69.43%	0.108	0.182	0.290	0.201
HCPC	0	0	0	0	0
PGV	0	0	0	0	0
Total	100.00%				0.367

Note:
Unit Rates = Total O&M $/Avoided Unit MWH
Net Rates = Unit Rates * % Avoided MWH

HELCO Avoided On-Peak O and M based on HELCO Simulation

ON-PEAK	MWH			Hours of operation			O&M Rates		Avoided O&M Costs, $		
	Base	QF IN	Diff.	Base	QF IN	Diff.	Consum.	Maint.	Consum.	Maint.	Total
Steam Units							(¢/kwh)	($/hr)			
Shipman 3	2,878	2,797	81	535	510	25	0.191	62.174	155	1,548	1,703
Shipman 4	1,415	1,458	-43	248	253	-5	0.191	62.174	-82	-292	-374
Hill 5	47,971	47,033	938	4,085	4,085	0	0.083	62.859	777	0	777
Hill 6	93,259	92,905	354	4,643	4,643	0	0.083	62.859	293	0	293
Puna	62,291	62,291	0	4,418	4,418	0	0.137	83.398	0	0	0
Diesel Units											
Waim EMD	3,678	3,474	204	1,718	1,590	128	0.098	18.382	200	0	200
D12	0	0	0	515	462	53	0.098	18.382	0	982	982
D13	0	0	0	715	665	50	0.098	18.382	0	915	915
D14	0	0	0	488	463	25	0.098	18.382	0	454	454
Kanoe EMD	5,830	5,753	77	2,977	2,914	63	0.094	20.286	72	0	72
D11	0	0	0	1,634	1,572	61	0.094	20.286	0	1,239	1,239
D15	0	0	0	427	426	1	0.094	20.286	0	22	22
D16	0	0	0	457	456	1	0.094	20.286	0	28	28
D17	0	0	0	459	460	0	0.094	20.286	0	-6	-6
Keah EMD	3,857	3,479	378	1,812	1,618	194	0.060	19.306	227	0	227
D21	0	0	0	477	422	56	0.060	19.306	0	1,073	1,073
D22	0	0	0	771	684	87	0.060	19.306	0	1,683	1,683
D23	0	0	0	564	513	51	0.060	19.306	0	985	985
Dispersed	369	313	56	413	349	64	0.566	0.000	317	0	317
D24	0	0	0	111	95	16	0.566	0.000	0	0	0
D25	0	0	0	100	85	15	0.566	0.000	0	0	0
D26	0	0	0	87	73	14	0.566	0.000	0	0	0
D27	0	0	0	115	97	19	0.566	0.000	0	0	0
CT-1	1,742	1,549	193	217	198	19	0.032	761.766	61	14,321	14,382
CT-2	5,237	3,873	1,364	451	342	109	0.297	95.720	4,046	10,462	14,508
CT-3	27,929	21,850	6,079	1,974	1,588	386	0.054	118.729	3,290	45,805	49,095
CT-4	95,508	92,459	3,049	4,604	4,604	0	0.087	95.312	2,657	0	2,657
CT-5	70,507	61,963	8,544	4,001	3,709	292	0.087	95.312	7,445	27,841	35,286
As-Available											
Lalamilo	1,098	1,098	0	0	0	0	0.000	0.000	0	0	0
HELCO Hydro	3,746	3,746	0	5,110	5,110	0	0.000	0.000	0	0	0

HELCO Avoided On-Peak O and M based on HELCO Simulation

	MWH			Hours of operation			O&M Rates		Avoided O&M Costs, $		
	Base	QF IN	Diff.	Base	QF IN	Diff.	Consum.	Maint.	Consum.	Maint.	Total
IPP							(¢/kwh)	($/hr)			
HEP	288,199	284,966	3,233	4,907	4,797	110	0.108	241.748	3,493	26,616	30,109
HCPC	0	0	0	0	0	0	0.000	0.000	0	0	0
PGV	95,049	95,049	0	3,586	3,586	0	0.000	0.000	0	0	0
TOTAL	810,563	786,056	24,507	52,617	50,783	1,834	[redacted]	[redacted]	22,953	133,679	156,631

Total Avoided Cost, cents/kwh	0.639

SUMMARY STATISTICS

ON-PEAK					
UNIT TYPE	% Avoided MWH	Rate (¢/kwh)			
		Consum.	Maint.	Total	Net
Base Steam	5.27%	0.083	0.000	0.083	0.004
Interm. Steam					
Shipman	0.16%	0.191	3.305	3.496	0.005
Puna	0.00%	0.000	0.000	0.000	0.000
CTs	78.46%	0.091	0.512	0.603	0.473
Diesel Units	2.92%	0.114	1.032	1.146	0.033
HEP	13.19%	0.108	0.823	0.931	0.123
HCPC	0	0	0	0	0
PGV	0	0	0	0	0
Total	100.00%	[redacted]	[redacted]	[redacted]	0.639

Note:
Unit Rates = Total O&M $/Avoided Unit MWH
Net Rates = Unit Rates * % Avoided MWH

HELCO Total Avoided O and M based on HELCO Simulation

TOTAL	MWH			Hours of operation			O&M Rates		Avoided O&M Costs, $		
	Base	QF IN	Diff.	Base	QF IN	Diff.	Consum. (¢/kwh)	Maint. ($/hr)	Consum.	Maint.	Total
Steam Units											
Shipman 3	2,962	2,879	83	549	524	25	0.191	62.174	159	1,548	1,707
Shipman 4	1,452	1,493	-41	255	259	-4	0.191	62.174	-78	-274	-352
Hill 5	73,754	72,296	1,458	7,002	7,002	0	0.083	62.859	1,208	0	1,208
Hill 6	154,055	153,285	770	7,960	7,960	0	0.083	62.859	638	0	638
Puna	106,417	105,461	956	7,573	7,573	0	0.137	83.398	1,305	0	1,305
Diesel Units											
Waim EMD	4,279	4,015	264	2,006	1,847	159	0.098	18.382	259	0	259
D12	0	0		596	536	60	0.098	18.382	0	1,108	1,108
D13	0	0		836	772	64	0.098	18.382	0	1,178	1,178
D14	0	0		573	538	35	0.098	18.382	0	636	636
Kanoe EMD	6,923	6,720	203	3,567	3,437	129	0.094	20.286	191	0	191
D11	0	0		1,958	1,867	91	0.094	20.286	0	1,842	1,842
D15	0	0		514	502	13	0.094	20.286	0	256	256
D16	0	0		548	535	14	0.094	20.286	0	278	278
D17	0	0		546	534	12	0.094	20.286	0	243	243
Keah EMD	3,973	3,593	380	1,865	1,669	196	0.060	19.306	229	0	229
D21	0	0		491	435	56	0.060	19.306	0	1,089	1,089
D22	0	0		793	705	88	0.060	19.306	0	1,695	1,695
D23	0	0		581	529	52	0.060	19.306	0	996	996
Dispersed	386	325	61	435	366	69	0.566	0.000	345	0	345
D24	0	0		117	100	18	0.566	0.000	0	0	0
D25	0	0		105	89	16	0.566	0.000	0	0	0
D26	0	0		91	76	15	0.566	0.000	0	0	0
D27	0	0		121	101	20	0.566	0.000	0	0	0
CT-1	1,857	1,642	215	235	213	22	0.032	761.766	68	16,530	16,599
CT-2	5,275	3,938	1,337	456	349	108	0.297	95.720	3,966	10,309	14,275
CT-3	29,451	23,017	6,434	2,108	1,695	413	0.054	118.729	3,482	48,987	52,470
CT-4	112,184	108,034	4,150	5,758	5,693	64	0.087	95.312	3,616	6,138	9,754
CT-5	79,808	69,804	10,004	4,642	4,256	387	0.087	95.312	8,717	36,867	45,584
As-Available											
Lalamilo	1,882	1,882	0	0	0	0	0.000	0.000	0	0	0
HELCO Hydro	6,330	6,330	0	8,760	8,760	0	0.000	0.000	0	0	0

HELCO Total Avoided O and M based on HELCO Simulation

	MWH			Hours of operation			O&M Rates		Avoided O&M Costs, $		
	Base	QF IN	Diff.	Base	QF IN	Diff.	Consum.	Maint.	Consum.	Maint.	Total
IPP							(¢/kwh)	($/hr)			
HEP	461,386	446,799	14,587	8,383	8,188	196	0.108	241.748	15,760	47,286	63,046
HCPC	0	0	0	0	0	0	0.000	0.000	0	0	0
PGV	151,404	151,404	0	6,148	6,148	0	0.000	0.000	0	0	0
TOTAL	1,203,778	1,162,917	40,861	67,700	65,938	1,762			39,865	176,714	216,579

Total Avoided Cost, cents/kwh	0.530

SUMMARY STATISTICS

TOTAL					
UNIT TYPE	% Avoided MWH	Rate (¢/kwh)			
		Consum.	Maint.	Total	Net
Base Steam	5.45%	0.083	0.000	0.083	0.005
Interm. Steam					
Shipman	0.10%	0.191	3.035	3.226	0.003
Puna	2.34%	0.137	0.000	0.137	0.003
CTs	54.18%	0.090	0.537	0.626	0.339
Diesel Units	2.22%	0.113	1.027	1.139	0.025
HEP	35.70%	0.108	0.324	0.432	0.154
HCPC	0	0	0	0	0
PGV	0	0	0	0	0
Total	100.00%				0.530

Note:
Unit Rates = Total O&M $/Avoided Unit MWH
Net Rates = Unit Rates * % Avoided MWH

MECO Avoided O&M Rates

	Unit Type	Consumables		Maintenance		COMMENTS
		Rate	Units	Rate	Units	
Kahului Power Plant						
Steam Units			¢/kwh		$/Hr	
Kahului 1	Intermediate	0.141		0.000		See Note 1
Kahului 2	Intermediate	0.141		0.000		See Note 1
Kahului 3	Base	0.141		0.000		See Note 1
Kahului 4	Base	0.141		0.000		See Note 1
Maalaea Power Plant						
Diesel Units			¢/kwh		$/Hr	
Maalaea 1	Peaking	0.263		15.913		See Note 1
Maalaea 2	Peaking	0.263		15.913		See Note 1
Maalaea 3	Peaking	0.263		15.913		See Note 1
Maalaea 4	Intermediate	0.263		12.092		See Note 1
Maalaea 5	Intermediate	0.263		12.092		See Note 1
Maalaea 6	Intermediate	0.263		12.092		See Note 1
Maalaea 7	Intermediate	0.263		12.092		See Note 1
Maalaea 8	Intermediate	0.263		7.062		See Note 1
Maalaea 9	Intermediate	0.263		7.062		See Note 1
Maalaea 10	Intermediate	0.263		35.743		See Note 1
Maalaea 11	Intermediate	0.263		35.743		See Note 1
Maalaea 12	Intermediate	0.263		35.743		See Note 1
Maalaea 13	Base	0.263		35.743		See Note 1
Maalaea X1	Peaking	0.263		15.913		See Note 1
Maalaea X2	Peaking	0.263		15.913		See Note 1
M17	Peaking	0.067		86.706		See Note 1
M19	Peaking	0.067		86.706		See Note 1
M1415	Base	0.067		87.861		See Note 1
M1615	Base	0.067		87.861		See Note 1

Notes:
1. MECO-WP-504 / Docket No. 97-0346 / Page 5 of 30. Escalated to 2005$ by Consumer Price Index-Urban for Honolulu

MECO Avoided Off-Peak O&M based on MECO Kaheawa Windfarm (30MW) Simulation

	Unit Type	MWH			Hours of operation			O&M Rates		Avoided O&M Costs, $		
		Base	QF in	Diff.	Base	QF in	Diff.	Consum.	Maint.	Consum.	Maint.	Total
Kahului Power Plant												
Steam Units								(¢/kwh)	($/Hr)			
Kahului 1	Intermediate	4,619	4,082	537	1,024	993	31	0.141	0.000	757	0	757
Kahului 2	Intermediate	5,127	4,510	617	1,130	1,101	29	0.141	0.000	870	0	870
Kahului 3	Base	36,602	32,534	4,068	3,374	3,374	0	0.141	0.000	5,736	0	5,736
Kahului 4	Base	38,730	34,824	3,906	3,350	3,350	0	0.141	0.000	5,507	0	5,507
Total		85,078	75,950	9,128	8,878	8,818	60			12,870	0	12,870
Maalaea Power Plant												
Diesel Units												
Maalaea 1	Peaking	120	10	110	58	6	52	0.263	15.913	289	827	1,116
Maalaea 2	Peaking	198	21	177	86	12	74	0.263	15.913	466	1,178	1,644
Maalaea 3	Peaking	300	34	266	132	17	115	0.263	15.913	700	1,830	2,530
Maalaea 4	Intermediate	843	202	641	211	56	155	0.263	12.092	1,686	1,874	3,560
Maalaea 5	Intermediate	1,194	344	850	305	113	192	0.263	12.092	2,236	2,322	4,558
Maalaea 6	Intermediate	1,508	504	1,004	484	209	275	0.263	12.092	2,641	3,325	5,966
Maalaea 7	Intermediate	1,754	787	967	718	337	381	0.263	12.092	2,543	4,607	7,150
Maalaea 8	Intermediate	3,377	1,592	1,785	853	401	452	0.263	7.062	4,695	3,192	7,887
Maalaea 9	Intermediate	4,728	2,299	2,429	1,187	584	603	0.263	7.062	6,388	4,258	10,646
Maalaea 10	Intermediate	23,531	12,685	10,846	2,067	1,151	916	0.263	35.743	28,525	32,741	61,266
Maalaea 11	Intermediate	30,722	18,206	12,516	2,961	1,955	1,006	0.263	35.743	32,917	35,957	68,874
Maalaea 12	Intermediate	30,194	22,874	7,320	3,435	2,948	487	0.263	35.743	19,252	17,407	36,659
Maalaea 13	Base	22,198	20,158	2,040	3,036	3,036	0	0.263	35.743	5,365	0	5,365
Maalaea X1	Peaking	45	0	45	25	0	25	0.263	15.913	118	398	516
Maalaea X2	Peaking	88	0	88	46	2	44	0.263	15.913	231	700	931
M17	Peaking	5,505	2,720	2,785	272	136	136	0.067	86.706	1,866	11,792	13,658
M19	Peaking	969	41	928	47	2	45	0.067	86.706	622	3,902	4,524
M1415	Base	95,803	95,546	257	3,582	3,582	0	0.067	87.861	172	0	172
M1615	Base	95,518	94,554	964	3,572	3,572	0	0.067	87.861	646	0	646
Total		318,595	272,577	46,018	23,077	18,119	4,958			111,358	126,310	237,668
TOTAL		403,673	348,527	55,146	31,955	26,937	5,018			124,228	126,310	250,538

Total Avoided Cost, Ct/KWH	0.454

MECO Avoided Off-Peak O&M based on MECO Kaheawa Windfarm (30MW) Simulation

SUMMARY STATISTICS

UNIT TYPE	% Avoided	Rate (¢/kwh)			
	MWH	Consum.	Maint.	Total	Net
Intermediate Steam (K1-2)	2.09%	0.141	0.000	0.141	0.003
Base Steam (K3-4)	14.46%	0.141	0.000	0.141	0.020
Peaking Diesel (X1,X2,M1-3)	1.24%	0.263	0.719	0.982	0.012
Intermediate Diesel (M4-M12)	69.56%	0.263	0.276	0.539	0.375
Base Diesel (M13)	3.70%	0.263	0.000	0.263	0.010
CT (M17,M19)	6.73%	0.067	0.423	0.490	0.033
DTCT (M141516)	2.21%	0.067	0.000	0.067	0.001
TOTAL	100.00%				0.454

Note:
Unit Rates = Total O&M $/Avoided Unit MWH
Net Rates = Unit Rates * % Avoided MWH

* Possible rounding errors of +/- 0.001 ¢/kwh

MECO Avoided On-Peak O&M based on MECO Kaheawa Windfarm (30MW) Simulation

		MWH			Hours of operation			O&M Rates		Avoided O&M Costs, $		
	Unit Type	Base	QF in	Diff.	Base	QF in	Diff.	Consum.	Maint.	Consum.	Maint.	Total
Kahului Power Plant												
Steam Units								(¢/kwh)	($/Hr)			
Kahului 1	Intermediate	20,915	20,892	23	4,441	4,438	3	0.141	0.000	32	0	32
Kahului 2	Intermediate	22,001	21,992	9	4,632	4,630	2	0.141	0.000	13	0	13
Kahului 3	Base	51,867	51,867	0	4,724	4,724	0	0.141	0.000	0	0	0
Kahului 4	Base	55,722	55,721	1	4,690	4,690	0	0.141	0.000	1	0	1
Total		150,505	150,472	33	18,487	18,482	5			46	0	46
Maalaea Power Plant												
Diesel Units												
Maalaea 1	Peaking	3,710	1,915	1,795	1,706	884	822	0.263	15.913	4,721	13,080	17,801
Maalaea 2	Peaking	4,787	2,635	2,152	2,133	1,173	960	0.263	15.913	5,660	15,276	20,936
Maalaea 3	Peaking	6,063	3,331	2,732	2,555	1,502	1,053	0.263	15.913	7,185	16,756	23,941
Maalaea 4	Intermediate	16,361	10,399	5,962	3,481	2,390	1,091	0.263	12.092	15,680	13,192	28,872
Maalaea 5	Intermediate	18,609	12,519	6,090	4,004	3,158	846	0.263	12.092	16,017	10,230	26,247
Maalaea 6	Intermediate	18,670	11,395	7,275	4,402	3,715	687	0.263	12.092	19,133	8,307	27,440
Maalaea 7	Intermediate	14,881	10,190	4,691	4,627	4,127	500	0.263	12.092	12,337	6,046	18,383
Maalaea 8	Intermediate	18,645	17,074	1,571	4,334	4,020	314	0.263	7.062	4,132	2,217	6,349
Maalaea 9	Intermediate	21,091	19,908	1,183	4,891	4,655	236	0.263	7.062	3,111	1,667	4,778
Maalaea 10	Intermediate	61,002	60,181	821	4,975	4,919	56	0.263	35.743	2,159	2,002	4,161
Maalaea 11	Intermediate	60,786	60,276	510	4,977	4,963	14	0.263	35.743	1,341	500	1,841
Maalaea 12	Intermediate	57,990	56,904	1,086	4,830	4,830	0	0.263	35.743	2,856	0	2,856
Maalaea 13	Base	49,502	44,972	4,530	4,250	4,250	0	0.263	35.743	11,914	0	11,914
Maalaea X1	Peaking	1,766	727	1,039	891	373	518	0.263	15.913	2,733	8,243	10,976
Maalaea X2	Peaking	2,596	1,224	1,372	1,262	586	676	0.263	15.913	3,608	10,757	14,365
M17	Peaking	36,761	15,654	21,107	1,950	835	1,115	0.067	86.706	14,142	96,677	110,819
M19	Peaking	2,840	186	2,654	193	10	183	0.067	86.706	1,778	15,867	17,645
M1415	Base	134,165	134,165	0	5,015	5,015	0	0.067	87.861	0	0	0
M1615	Base	133,791	133,791	0	5,001	5,001	0	0.067	87.861	0	0	0
Total		664,016	597,446	66,570	65,477	56,406	9,071			128,507	220,817	349,324
TOTAL		814,521	747,918	66,603	83,964	74,888	9,076			128,553	220,817	349,370

Total Avoided Cost, ¢/kwh	0.525

MECO Avoided On-Peak O&M based on MECO Kaheawa Windfarm (30MW) Simulation
SUMMARY **STATISTICS**

ON-PEAK					
UNIT TYPE	% Avoided MWH	Rate (¢/kwh)			
		Consum.	Maint.	Total	Net
Intermediate Steam (K1-2)	0.05%	0.141	0.000	0.141	0.000
Base Steam (K3-4)	0.00%	0.100	0.000	0.100	0.000
Peaking Diesel (X1,X2,M1-3)	13.65%	0.263	0.705	0.968	0.132
Intermediate Diesel (M4-M12)	43.83%	0.263	0.151	0.414	0.181
Base Diesel (M13)	6.80%	0.263	0.000	0.263	0.018
CT (M17,M19)	35.68%	0.067	0.474	0.541	0.193
DTCT (M141516)	0.00%	0.000	0.000	0.000	0.000
TOTAL	100.00%				0.524

Note:
Unit Rates = Total O&M $/Avoided Unit MWH
Net Rates = Unit Rates * % Avoided MWH

* Possible rounding errors of +/- 0.001 ¢/kwh

MECO Avoided Total O&M based on MECO Kaheawa Windfarm (30MW) Simulation

	Unit Type	MWH			Hours of operation			O&M Rates		Avoided O&M Costs, $		
		Base	QF in	Diff.	Base	QF in	Diff.	Consum.	Maint.	Consum.	Maint.	Total
Kahului Power Plant												
Steam Units								(¢/kwh)	$/Hr			
Kahului 1	Intermediate	25,534	24,974	560	5,465	5,431	34	0.141	0.000	790	0	790
Kahului 2	Intermediate	27,128	26,502	626	5,762	5,731	31	0.141	0.000	883	0	883
Kahului 3	Base	88,469	84,401	4,068	8,098	8,098	0	0.141	0.000	5,736	0	5,736
Kahului 4	Base	94,452	90,545	3,907	8,040	8,040	0	0.141	0.000	5,509	0	5,509
Total		235,583	226,422	9,161	27,365	27,300	65			12,918	0	12,918
Maalaea Power Plant												
Diesel Units												
Maalaea 1	Peaking	3,830	1,925	1,905	1,764	890	874	0.263	15.913	5,010	13,908	18,918
Maalaea 2	Peaking	4,985	2,656	2,329	2,219	1,185	1,034	0.263	15.913	6,125	16,454	22,579
Maalaea 3	Peaking	6,363	3,365	2,998	2,687	1,519	1,168	0.263	15.913	7,885	18,586	26,471
Maalaea 4	Intermediate	17,204	10,601	6,603	3,692	2,446	1,246	0.263	12.092	17,366	15,067	32,433
Maalaea 5	Intermediate	19,803	12,863	6,940	4,309	3,271	1,038	0.263	12.092	18,252	12,551	30,803
Maalaea 6	Intermediate	20,178	11,899	8,279	4,886	3,924	962	0.263	12.092	21,774	11,633	33,407
Maalaea 7	Intermediate	16,635	10,977	5,658	5,345	4,464	881	0.263	12.092	14,881	10,653	25,534
Maalaea 8	Intermediate	22,022	18,666	3,356	5,187	4,421	766	0.263	7.062	8,826	5,409	14,235
Maalaea 9	Intermediate	25,819	22,207	3,612	6,078	5,239	839	0.263	7.062	9,500	5,925	15,425
Maalaea 10	Intermediate	84,533	72,866	11,667	7,042	6,070	972	0.263	35.743	30,684	34,742	65,426
Maalaea 11	Intermediate	91,508	78,482	13,026	7,938	6,918	1,020	0.263	35.743	34,258	36,458	70,716
Maalaea 12	Intermediate	88,184	79,778	8,406	8,265	7,778	487	0.263	35.743	22,108	17,407	39,515
Maalaea 13	Base	71,700	65,130	6,570	7,286	7,286	0	0.263	35.743	17,279	0	17,279
Maalaea X1	Peaking	1,811	727	1,084	916	373	543	0.263	15.913	2,851	8,641	11,492
Maalaea X2	Peaking	2,684	1,224	1,460	1,308	588	720	0.263	15.913	3,840	11,457	15,297
M17	Peaking	42,266	18,374	23,892	2,222	971	1,251	0.067	86.706	16,008	108,469	124,477
M19	Peaking	3,809	227	3,582	240	12	228	0.067	86.706	2,400	19,769	22,169
M1415	Base	229,968	229,711	257	8,597	8,597	0	0.067	87.861	172	0	172
M1615	Base	229,309	228,345	964	8,597	8,597	0	0.067	87.861	646	0	646
Total		982,611	870,023	112,588	88,578	74,549	14,029			239,865	347,129	586,994
TOTAL		1,218,194	1,096,445	121,749	115,943	101,849	14,094			252,783	347,129	599,912

Total Avoided Cost, ¢/kwh	0.493

MECO Avoided Total O&M based on MECO Kaheawa Windfarm (30MW) Simulation
SUMMARY STATISTICS

TOTAL					
UNIT TYPE	% Avoided MWH	Rate (¢/kwh)			
		Consum.	Maint.	Total	Net
Intermediate Steam (K1-2)	0.97%	0.141	0.000	0.141	0.001
Base Steam (K3-4)	6.55%	0.141	0.000	0.141	0.009
Peaking Diesel (X1,X2,M1-3)	8.03%	0.263	0.706	0.969	0.078
Intermediate Diesel (M4-M12)	55.48%	0.263	0.222	0.485	0.269
Base Diesel (M13)	5.40%	0.263	0.000	0.263	0.014
CT (M17,M19)	22.57%	0.067	0.467	0.534	0.121
DTCT (M141516)	1.00%	0.067	0.000	0.067	0.001
TOTAL	100.00%	[redacted]			0.493

Note:
Unit Rates = Total O&M $/Avoided Unit MWH
Net Rates = Unit Rates * % Avoided MWH

* Possible rounding errors of +/- 0.001 ¢/kwh

MECO Diesel Maintenance Costs
Docket No. 7310, Avoided Cost

UNIT	O/H Hrs	Average O/H Cost (1999$)	1999$/Hr	2005$/Hr
X1	8,000	113,910	14.24	16.14
X2	8,000	113,910	14.24	16.14
M1	8,000	113,910	14.24	16.14
M2	8,000	113,910	14.24	16.14
M3	8,000	113,910	14.24	16.14
M4	20,000	216,407	10.82	12.27
M5	20,000	216,407	10.82	12.27
M6	20,000	216,407	10.82	12.27
M7	20,000	216,407	10.82	12.27
M8	18,000	113,742	6.32	7.17
M9	18,000	113,742	6.32	7.17
M10	12,000	383,801	31.98	36.26
M11	12,000	383,801	31.98	36.26
M12	12,000	383,801	31.98	36.26
M13	12,000	383,801	31.98	36.26

Source: MECO-WP-504 / Docket No. 97-0346 / Page 5 of 30

* Consumer Price Inflation (from 1998 to 2005)= 1.13372

AVOIDED O&M ESCALATION

The avoided consumables and maintenance costs for each utility will be adjusted annually by the rate of inflation to reflect estimated increases (or decreases) in cost due to general price changes.

The inflation index used to adjust avoided O&M cost will be the CPI-U for Honolulu. At this time, the Honolulu CPI-U is published semi-annually for the first and second half of the year by the Bureau of Labor Statistics, U.S. Department of Labor. The latest CPI-U for Honolulu is 195.0 (1982-1984 = 100 index) for the 1st half of 2005.

Since the avoided energy cost will be calculated for review during the fall of the preceding year, the CPI-U used to annually escalate avoided consumables and maintenance costs will the 1st half CPI-U. Each Company may have different base years for initial avoided cost of consumables and maintenance, thus the escalation adjustment may be different for each company.

Therefore, if the initial avoided cost of consumables and maintenance was expressed in 1993 dollars (as is the case for HECO), the adjusted cost for 2006 would be:

$$\text{Avoided O\&M cost (2006)} = \text{Initial O\&M cost (\$1993)} \times \frac{\text{1st half 2005 CPI-U}}{\text{1st half 1993 CPI-U}}$$

Alternatively, if the initial avoided cost of consumables and maintenance was expressed in 1998 dollars (as is the case for HELCO and MECO), the adjusted cost for 2006 would be:

$$\text{Avoided O\&M cost (2006)} = \text{Initial O\&M cost (\$1998)} \times \frac{\text{1st half 2005 CPI-U}}{\text{1st half 1998 CPI-U}}$$

If the 1st half Honolulu CPI-U is not available, then the next most recent value will be used and updated when the 1st half CPI-U becomes available.

Should the CPI-U index base (1982-1984 = 100) change, the Companies will choose an inflation index published by the Bureau of Labor Statistics which is consistent with the intent of this adjustment.

CALCULATION OF PURCHASED ENERGY PAYMENT LAG

The companies incur purchased energy expense over a period of a calendar month. To simplify the calculation of payment lag, and to be consistent with the manner that HECO, HELCO, and MECO calculates payment lags in rate proceedings, the expense is assumed to be incurred evenly throughout the month. Mathematically, this is equivalent to assuming the entire expense is incurred in the middle of the month. Thus, the expense is incurred 15 days before the end of the month.

If a purchased power agreement (PPA) provides for payment 30 days from the end of the previous month, the payment lag is 15 days + 30 days, or 45 days. Similarly, if the PPA provides for a payment 20 days from the end of the previous month, the payment lag is 35 days.

Update Schedule for Avoided Working Cash Calculation for Impact on Fuel and Purchased Energy

Reference	Avoided Working Cash Calculation Factor	Update Interval
(1)	fuel oil payment lag days	Rate Case D&O
(2)	purchased energy payment lag days	New Purchased Power Contracts or Contract Amendments to payment terms
(3)	rate of return on rate base	Rate Case D&O
(4)	weighted cost of debt	Rate Case D&O
(5)	composite income tax rate	Rate Case D&O or Other D&O adjusting income tax rate embedded in rates
(6)	avoided fuel working cash factor	See (1) - (5) above
(7)	avoided fuel cost	Monthly
(8)	avoided fuel working cash	See (1) - (5) and (7) above; in effect, updated monthly for changes in fuel prices

Update Schedule for Avoided Working Cash Calculation for Impact on O&M

Reference	Avoided Working Cash Calculation Factor	Update Interval
(1)	O&M payment lag days (a)	Rate Case D&O
(2)	purchased energy payment lag days	New Purchased Power Contracts or Contract Amendments to payment terms
(3)	rate of return on rate base	Rate Case D&O
(4)	weighted cost of debt	Rate Case D&O
(5)	composite income tax rate	Rate Case D&O or Other D&O adjusting income tax rate embedded in rates
(6)	avoided O&M working cash factor	See (1) - (5) above
(7)	avoided O&M cost	Annual
(8)	avoided O&M working cash	See (1) - (5) and (7) above

Reference:

(a) O&M payment lag days are based on the "Non-Labor" payment lag days approved by the Commission in the general rate cases.

Update Schedule for Avoided Fuel Inventory Calculations

Line	Avoided Fuel Inventory Calculation	Update Interval
(1)	days of fuel inventory	Rate Case D&O
(2)	million btus fuel avoided	Annual
(3)	fuel price ($/mbtu)	Rate Case D&O
(4)	rate of return on rate base	Rate Case D&O
(5)	weighted cost of debt	Rate Case D&O
(6)	composite income tax rate	Rate Case D&O or Other D&O adjusting income tax rate embedded in rates
(7)	as-available QF energy (mwh)	Annual
(8)	avoided fuel inventory (¢/kwh)	See (1) - (7) above

AVOIDED STEP-UP TRANSFORMER LOSSES

Company	Adjustment Factor	Source
HECO	0.34%	HSP-IR-254, page 3
HELCO	0.50%	HSP-IR-467, page 3
MECO (Maui)	0.53%	HSP-IR-467, page 3

Update of Avoided Step-Up Transformer Losses

The percentage adjustment factors may be updated based on system loss studies used in general rate cases.

CERTIFICATE OF SERVICE

I hereby certify that I have this date served a copy of the foregoing Decision and Order No. 24086 upon the following parties, by causing a copy hereof to be mailed, postage prepaid, and properly addressed to each such party.

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DATED: MAR 11 2008