BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

In The Matter Of the Application Of PUBLIC UTILITIES COMMISSION Instituting a Proceeding to Investigate Distributed Generation in Hawaii.	DOCKET NO. 03-0371

REPLY BRIEF

AND

CERTIFICATE OF SERVICE

GOODSILL ANDERSON QUINN & STIFEL
A LIMITED LIABILITY LAW PARTNERSHIP LLP

THOMAS W. WILLIAMS, JR.
PETER Y. KIKUTA
Alii Place, Suite 1800
1099 Alakea Street
Honolulu, Hawaii 96813
Telephone: (808) 547-5600
Facsimile: (808) 547-5880

Attorneys for
HAWAIIAN ELECTRIC COMPANY, INC.
HAWAII ELECTRIC LIGHT COMPANY, INC.
MAUI ELECTRIC COMPANY, LIMITED

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REPLY BRIEF

This Reply Brief is respectfully submitted on behalf of Hawaiian Electric Company, Inc. ("HECO"), Maui Electric Company, Limited ("MECO") and Hawaii Electric Light Company, Inc. ("HELCO") (collectively, the "HECO Companies").

The HECO Companies' Opening Brief ("OB") filed March 7, 2005 generally addresses the contentions included in the other parties' Opening Briefs.[1] Therefore, this Reply Brief will not attempt to be all-inclusive, and will focus on those contentions that may warrant further response.

I. DISCUSSION

A. UTILITIES SHOULD BE PERMITTED TO OWN AND OPERATE CUSTOMER-SITED DISTRIBUTED GENERATION PROJECTS AS A REGULATED SERVICE

1. CA's Position

The Division of Consumer Advocacy ("CA") stated that utilities should be allowed to offer customer-sited distributed generation ("DG") systems as a regulated service. The CA also stated that a "level playing field" could exist even if utilities are allowed to own, operate and

[1] References to the HECO Companies' Opening Brief are intended to incorporate the references to the record and authorities cited in the Opening Brief. The citations generally will not be repeated in this Reply Brief for the sake of brevity.

maintain customer-sited DG because any information about customer loads and potential customer-sited DG locations may be obtained by third-party vendors directly from customers. In addition, the CA did not recommend that such services be provided as an unregulated service, because the utilities' involvement in the customer-sited DG market would focus on reliability in a manner consistent with central utility planning in contrast to an unregulated subsidiary's focus which may be on cost and profit of customer-sited DG projects. See CA OB at 9-13.

The HECO Companies are in agreement with the CA that utilities should be allowed to provide customer-sited combined heat and power ("CHP") systems on a regulated basis.[2] As discussed in the HECO Companies' Opening Brief, (1) providing CHP systems is an appropriate Hawaii utility program, (2) customers want the utility CHP option for a variety of reasons (e.g., the HECO Companies offer options generally not offered by third parties, the HECO Companies are subject to Commission regulation), (3) competitors are free to offer services as the HECO Companies' proposed CHP program does not restrict third parties from offering the same product in any way, and non-utilities enjoy advantages not available to the utility, and (4) participants and non-participants are better off with utility participation. See HECO Companies' OB at 8-48.

In addition, as discussed in the HECO Companies' Opening Brief, the HECO Companies need authority to proceed now with CHP installations. HECO has an urgent need for firm generating capacity with the forecasted firm capacity contributions of the proposed CHP Program[3] in combination with the energy efficiency and load management demand-side

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2 The HECO Companies discussed the differences between DG and CHP on page 2 (footnote 2) of their Opening Brief.

3 The HECO Companies filed an application for approval of a CHP Program in Docket No. 03-0366.

management ("DSM") program impacts.[4] Therefore, options to mitigate the effects of the higher peak forecasts are necessary. Such options include approval to proceed with a CHP program and/or CHP installations as soon as possible. See HECO Companies' OB at 44. MECO also has a near-term need for the capacity provided by CHP systems, and HELCO will benefit from the addition of CHP systems. See HECO Companies' OB at 44-46.

Further, the HECO Companies need authority to proceed with their proposed CHP offering in order to meet the reasonable needs and expectations of their customers. There are currently a number of commercial customers that are ready to proceed now with CHP system installations. Some of these customers want to install CHP systems in connection with expansions or renovations of their operations or facilities. See HECO Companies' OB at 47-48.

Moreover, allowing the utility to proceed would avoid negative impacts on non-participating customers due to the unnecessary loss of revenues if a customer installs a third-party CHP system. Some customers may install third-party CHP systems rather than continue to wait for regulatory proceedings to conclude in "due course". As discussed in the HECO Companies' Opening Brief, the HECO Companies' proposed CHP Program is predicated not only on offering new energy-efficient options to commercial customers and addressing load growth, but also on protecting the interests of the HECO Companies' non-participating customers. Simply stated, non-participating customers should be better off when the HECO Companies own, operate and maintain cost-effective customer-sited CHP systems, than when the systems are installed by third-parties (and the electric revenue displaced by such systems are lost). See HECO Companies' OB at 14-15, 37-41.

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4 This need is due in large part to the record increasing demands for electricity. The next central-station generating unit is currently scheduled for installation in 2009, and it is not expected that a unit can be installed sooner than 2009.

Further delaying the start of utility-owned CHP installations for any significant period of time could irrevocably harm ratepayers, the HECO Companies and CHP Program customers. Particularly on Oahu, load is growing faster than was anticipated. Even with central station deferral benefits expected from its CHP Program, the need date for new generation on Oahu is sooner than when new generation can be added to the system, and the installation of utility-owned CHP systems can help mitigate reserve capacity shortfalls. In addition, the HECO Companies should be allowed to proceed now with CHP installations for customers that are renovating or expanding their facilities.

2. Other Parties' Arguments

The County of Maui ("COM") contends that a utility should not be permitted to offer customer-sited DG as a regulated service and erroneously relies on the Wind Power Pacific case[5] to support its position.[6] See COM OB at 3 & n.1 (referencing COM response to HECO/Maui-DT-IR-41). The Wind Power Pacific case is not applicable to this situation and does not support COM's argument that the HECO Companies should be prohibited for providing

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5 In re Wind Pacific Investors – III, 67 Haw. 342, 345, 686 P.2d 831 (1984).

6 In the Wind Power Pacific Investors-III ("WPPI-III") and Waikoloa Water Company, Inc. ("WWC") matter, the two entities filed a joint application requesting certification of a proposed wind facility as a qualifying facility ("QF"). WPPI-III was to be the owner of the facility and WWC was to be the operator of the facility, and to have primary responsibility for the operation and maintenance ("O&M") of the facility (although it would subcontract certain O&M functions to WPPI-III). WWC would purchase energy from the facility to operate the electric pumps on its two deep water wells located adjacent to the facility, and WWC would sell energy excess to WWC's "internal needs" to HELCO (with the revenue going to WPPI-III).

While the primary issue was whether the wind facility was a QF, an issue was raised as to whether WPPI-III would be a "public utility". The Commission found that WPPI-III would not be a public utility, and the Hawaii Supreme Court affirmed. Neither the Commission nor the Supreme Court found that the exception (then found in subparagraph 7 of the definition of a "public utility" in H.R.S. §269-1) excluded WPPI-III from the definition of a public utility. Rather, both the Commission and the Supreme Court found that there was no intent on the part of WPPI-III to dedicate its facilities to the public use. Re Wind Power Pacific Investors — III and Waikoloa Water Co., Docket No. 4779, Decision and Order No. 7578 (June 20, 1983) at 15.

The Commission's decision was affirmed on appeal In re Wind Power Pacific Investors-III, 67 Haw. 342, 686 P.2d 831 (1984). The Supreme Court based its affirmance on deference to the Commission's construction of the Hawaii public utilities law, the legislative intent behind H.R.S. §269-1(7) (which was to encourage the commercial development of renewable energy resources by producers who desired not to be deemed public utilities), and the concept of dedication to public use implicit in the term "public utility". In re Wind Pacific Investors – III, 67 Haw. 342, 345, 686 P.2d 831 (1984).

customer-sited CHP services on a regulated basis.

The Wind Power Pacific case addressed private ownership of a wind power facility that sold power to a utility, not ownership by a public utility. In addition, COM acknowledged that (1) the Wind Power Pacific case does not prohibit HELCO from owning the wind power facility, and (2) the Wind Power Pacific case does not state that if the wind power facility had been owned by HELCO it could not have been treated as a utility facility. COM was also not aware that Lalamilo Wind Farm (which was initially constructed as a third-party independent power producer project selling energy to the Department of Water Supply with excess power sold to HELCO) is currently owned by HELCO. Tr. (12/8/04) at 199-200 (Kobayashi).

The other cases referred to by Hawaii Renewable Energy Alliance ("HREA") are also inapplicable and not persuasive. See HREA OB at 20-21. For example, the New Mexico Public Utility Commission decision referred to by HREA involved the New Mexico commission's denial of unincorporated divisions of the Public Service Company of New Mexico request to provide non-utility services on a tariff basis (e.g., power quality services, maintenance and repair services, energy information services). This case did not involve a core utility service that the HECO Companies are proposing to provide - - the generation of electricity.

In addition, the Louisiana Public Service Commission ("PSC") decision referred to by HREA is also not persuasive. In this decision, the Louisiana PSC determined that a cogeneration facility that was co-owned by an unregulated subsidiary of Entergy Corporation should not be regulated by the Louisiana PSC because the cogeneration facility was not subject to state jurisdiction. However, in contrast to the situation in Louisiana, the HECO Companies are proposing to own the CHP facility and not have the CHP facilities owned by a non-regulated subsidiary.

3. COM's Virtual Power Plant Concept

COM contends that a utility should provide a virtual power plant ("VPP") program that could be used to address capacity shortfall situations. See COM OB at 42-43. (COM's recommendation appears to go well beyond the scope of this docket.) COM has not provided any detailed analysis concerning its proposed VPP concept. COM wants MECO to study the VPP concept. At the panel hearing, COM stated that it wanted the VPP concept to be studied as part of MECO's IRP-3 process. Tr. (12/9/04) at 83 (Lazar).

The HECO Companies are agreeable to undertake a feasibility study of the VPP concept for the island of Maui within the next major MECO IRP review (i.e., MECO IRP-3), provided that the full costs of the study are recoverable via the IRP Cost Recovery Provision. The HECO Companies have a number of issues and concerns with the VPP concept, including the actual availability of the emergency generators during times of system need, air permit limitations, noise, emissions and increased fuel truck traffic, lack of control over testing and maintenance practices for the emergency generators, potential lack of adequate dispatch control, and fuel storage capacity. Moreover, HECO is implementing a Commercial and Industrial Direct Load Control Program that will allow customers to take advantage of their emergency generators, to the extent that proves to be feasible, to provide interruptible "capacity" to the company. See HECO Companies' OB, Exhibit "C" at 1-7.

B. CONDITIONS ON UTILITY PARTICIPATION

1. Applications For Approval Of DG Projects

One of the CA's recommendations in response to the Commission's issue number 7 concerning any conditions that should be imposed on the utilities if the utilities are permitted to install customer-sited DG on a regulated basis was that "the Commission should require utilities offering DG as a regulated service to submit, for Commission review and approval, applications to install customer-sited DG. This requirement will provide an opportunity for interested parties to express their specific concerns with the utilities' application to the Commission." CA OB at 28.

The CA's proposed condition that an application requesting approval for each customer-sited DG project be submitted will not be necessary for CHP projects developed pursuant to the HECO Companies' proposed CHP Program and Schedule CHP tariff, provided the CHP Program and tariff is approved by the Commission. In addition, utility customer-sited DG offered outside of any approved tariffs (e.g., Schedule CHP tariff, provided it is approved) will generally require special contracts which are subject to Commission review and approval under the HECO Companies' Rule 4.[7]

The terms of the HECO Companies' proposed CHP Program provides an opportunity for review of the individual CHP agreements for customer-cited CHP installations. The CHP Program provides that following execution of a CHP agreement with a customer, the HECO Companies will file a forty-five day "file and suspend" notice transmittal with the Commission (which will be served on the CA) for a CHP system specifying the customer, the estimated capital costs for the CHP system, the rate components, and the effective date of the CHP agreement, together with the CHP agreement. The forty-five day notice file and suspend CHP system notice transmittal will be kept open for public inspection (except that the thermal charge and customer information deemed to be confidential and proprietary will be deleted and filed pursuant to a Protective Order issued by the Commission). CHP Program Application[8] at 34-35.

The forty-five day file and suspend notice transmittal will provide an opportunity for the

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[7] Under Rule 4 of the HECO Companies' respective tariffs, special contracts for service other than that provided for under the tariffs must be authorized by the Commission prior to the effective date of such contracts.

[8] HECO Companies' application filed October 10, 2003 in Docket No. 03-0366.

Commission and the CA (and other parties) to have additional time to review the CHP Agreement if they consider it necessary (by the Commission issuing an order suspending the effective date). The forty-five day notice feature will also give customers reasonable assurance as to when and whether Company-owned CHP system projects will proceed (if no order is issued suspending the effective date). Many customers will not make a decision to move forward with a CHP project until they have some stimulus such as aging equipment that needs to be replaced or changes in their operating conditions that require additional central plant investment. At the time they decide to move forward, customers then want the utility to move at the same pace as the unregulated competition. CHP Program Application at 36.

As discussed in the CHP Program Application (pages 34 to 36) the "file and suspend" provisions would operate as follows:

- Following execution of a CHP Agreement with a customer, the HECO Companies will file a forty-five day file and suspend notice transmittal with the Commission for a CHP system specifying the customer, the estimated capital costs for the CHP system, the rate components, and the effective date of the CHP Agreement, together with the CHP Agreement. The effective date of the CHP Agreement must be at least forty-five days after the filing of the forty-five day file and suspend CHP system notice transmittal. The forty-five day file and suspend CHP system notice transmittal will have attached to it a certificate of service showing service, at the time of filing, on the CA. The forty-five day notice file and suspend CHP system notice transmittal will be kept open for public inspection (except that the thermal charge and customer information deemed to be confidential and proprietary will be deleted and filed pursuant to a Protective Order issued by the Commission).

- The effective date of the CHP Agreement will be the first day of the month following the expiration of the notice period (of at least 45 days), unless the Commission issues an order suspending the effective date of the agreement within the notice period.
- If the Commission issues an order suspending the effective date of the CHP Agreement, the CHP Agreement will not be effective until the first day of the month following the Commission's issuance of an order allowing the CHP Agreement to take effect.
- If the Commission issues an order suspending the effective date of the CHP Agreement, and the effective date of the CHP Agreement is delayed by more than forty-five days as a result of the suspension order, then either the customer or the HECO Companies may terminate the CHP Agreement by providing written notice of such termination prior to the effective date of the CHP Agreement.
- If the Commission conditions its order allowing the CHP Agreement to take effect upon the Company and the customer agreeing to modifications to the CHP Agreement, the company and the customer must execute a conforming amendment to the CHP Agreement with the required modifications within forty-five days of the issuance of the order (unless such period is extended by mutual written agreement), and the CHP Agreement will not be effective until the first day of the month following execution and filing with the Commission of the conforming amendment; provided that if the customer, or the HECO Companies

elect not to execute such a conforming amendment within such forty-five day period, as extended, then the CHP Agreement is terminated.

2. <u>Conditions Proposed By Hess Concerning Interconnection</u>

Hess Microgen, LLC ("Hess") proposed that a time period be established for the length of time it will take the utility to determine whether an application for interconnection of a DG unit to operate in parallel with a utility's system is complete and that once the completeness determination is made it should take no longer than 4 to 6 months to complete an interconnection study. In addition, if the process takes longer then the applicant should have a process to file a complaint with the Commission. Hess OB at 4-5.

The HECO Companies are not opposed to modifying the Interconnection Process Overview in Appendix III of the HECO Companies' Rule 14.H to reflect an initial application completeness review period. This completeness review step would establish that from the time the applicant first submits its Interconnection Agreement ("IA") application, the utility would review the application for completeness and issue a written response to the applicant within a set number of business days. The utility would inform the applicant either that the application is deemed complete, or that further information is required. If further information is required, the utility would inform the applicant of the specific information that is needed to complete the IA application. Upon submittal of the additional information, the utility would again review the IA application for completeness and issue appropriate letters documenting application completeness or the continued need for information.

From the date that an IA application is deemed complete, the procedures and timeframes described in Appendix III, Section 2.c of Rule 14.H would apply. The utility will perform an initial technical screening study of the impact of the proposed DG facility on the utility's system and provide the applicant with the findings of this study within 15 business days. No charge will be assessed to the applicant for this initial study. If the utility determines that additional technical study of the interconnection proposal is necessary, then the utility will notify the applicant of such and identify the anticipated date to complete any required additional technical study.

As discussed below, it is not appropriate to impose a four to six month timeframe to complete the entire interconnection review process. The interconnection review process, from the first communications an applicant has with the HECO Companies to the execution of an interconnection agreement, involves a number of steps where there may be variability in timeframes and over which the HECO Companies have no control. In the first stage of the process, an applicant may not submit all required information to support a completeness determination. If additional technical study is required, there will be variability in the scope of work and duration of the study as described below. The HECO Companies anticipate that most additional technical studies can be completed within four to six months, provided that all required information to conduct the study is available. In any case, a schedule for the analyses to be done as part of the additional technical study will be provided to the applicant before the study is started, in accordance with Appendix III Section 3.d of Rule 14.H. Following completion of the additional technical study, the applicant may or may not agree to all the findings of the study.

There already is an existing dispute resolution process included in the HECO Companies' Rule 14.H. Appendix III Section 4.a of Rule 14.H outlines the dispute resolution process, including filing with the Commission, if there is disagreement between the applicant and the utility as to whether additional technical study is required, or as to the scope and cost of the study. In addition, Appendix III, Section 4.c of Rule 14.H provides that the applicant will still have the opportunity to file a complaint with the Commission on any matters concerning the interconnection process as the dispute resolution process in Rule 14.H does not supercede the Commission's existing complaint process.

Hess also proposed a queing system for interconnection review. Hess OB at 3.

A "first-in, first-out" queuing system could be applied to the initial screening study stage in the interconnection review process, as the timeframe for conducting the initial technical screening study is discrete and relatively short once an IA application is deemed complete, and the outputs of the initial screening study are general in nature. It would not be appropriate, however, to implement a first-in, first-out system going forward primarily because some IA applications will require additional technical studies and the scope and duration of such studies will vary depending on the specific characteristics of each DG project.[9] Simply put, DG projects with highly complex interconnection issues will take longer to analyze. DG projects requiring additional study but with fewer interconnection issues should not be forced to "stand in line" by a queuing system.

It is unreasonable to implement a first-in, first-out system for interconnection reviews because of the variable nature of each DG project. To illustrate this, an analogy can be drawn to servicing customers at a bank. It is reasonable and expected for a bank to require its customers to stand in line to wait for an available teller. However, once the customers are at the teller windows, customers will require different services and the lengths of their transactions will vary.

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9 Appendix III, Section 3.a of Rule 14.H describes a number of possible triggers for additional technical study, each of which requires a different scope of work and duration for analysis. As stated, "The need for additional technical study of the interconnection proposal may be triggered by considerations such as: (1) complexity of the utility system that the generating facility is proposed to be interconnected to that must be modeled (i.e., the distribution, subtransmission or transmission system); (2) connection to a network system; (3) plan to export power; (4) feeder penetration greater than 10%; (5) short circuit contribution ratio greater than 5%; and (6) other circumstances."

There are also multiple tellers handling the transactions, and so customers will be serviced in parallel by the different tellers as well as in series when considering the perspective of an individual teller. Thus, although a queue is used to fairly regulate initial entry into the customer service system, its usefulness and applicability ends the moment the customers arrive at a teller window. In a similar fashion, a queuing system is not practical or appropriate for the interconnection process once the additional technical study phase is triggered.

Further, Hess suggested that a non-utility DG provider should have the option to receive expedited interconnection review by paying for a dedicated engineer to evaluate its project. Hess OB at 4. Appendix III, Section 3.b of Rule 14.H adequately provides for this option, stating as follows: "Generally, the Company will perform the analyses included in the additional technical study. The analyses or parts of the analyses may be contracted to an outside consultant specializing in such analyses for complex situations or in situations where the Company's engineering department does not have available resources to conduct the analyses in a time frame mutually agreeable to both the Company and the Customer."

Moreover, Hess suggested that "interconnection people at the utility who do administrative functions should not be part of the utility DG group." Hess OB at 4. The HECO Companies interpret this suggestion to mean that utility personnel administering the interconnection review process should be separate from utility personnel involved in developing DG projects. With regard to customer-sited DG, where competitive situations may arise, utility organizational structures and processes should be geared to minimize the potential for conflicts of interest in utility interconnection reviews for utility and non-utility DG projects. Utility-sited DG projects, however, can and should be given greater flexibility.

HECO's Engineering Department administers the interconnection review process for both utility as well as non-utility DG projects. HECO's Energy Projects Department oversees the development of all customer-sited utility DG projects. The Energy Projects Department submits these projects to the Engineering Department for interconnection review, and plays no role in the interconnection reviews of non-utility DG projects. In this respect, HECO has already established an organizational structure which avoids potential conflicts of interest in interconnection reviews of customer-sited DG.

HECO's Engineering Department does play a role in developing utility-sited DG for transmission and distribution purposes. Utility-sited projects generally do not pose competitive issues with non-utility DG developers, hence it is acceptable and appropriate for the Engineering Department to remain involved in both the project development and interconnection review.

3. Customer Retention Discounts

Hess recommends that one of the conditions that should be imposed on a utility if it is permitted to provide DG services to customers on a regulated basis is that a utility should not be permitted to offer customer retention discounts, as such discounts could give a utility a competitive advantage over a non-utility DG provided. Hess OB at 8.

In general, customer retention rates are designed to retain loads for recovery of fixed cost-related revenues from customers with viable alternative energy suppliers. These energy rate discounts such customers receive result in lower future rate impacts than the alternative of losing the entire load and its contribution to recovery of fixed costs which would be shifted to other ratepayers. HECO Companies' OB at 132.

Currently, in light of the filing of the HECO Companies' CHP Program application in Docket No. 03-0366, and the evolution of the HECO Companies' approach to DG/CHP, HECO and HELCO have reevaluated the applicability of Rule 4 load retention contracts.[10] In HECO's 2005 test year rate case, HECO has proposed to discontinue the Standard Customer Retention Rate provided for in HECO's Rule 4, Section D. HECO Companies' OB at 133.

Within the HECO Companies, Rule 4 Standard Form Contracts for Customer Retention are only in effect for HECO and HELCO. MECO does not have a Rule 4 Standard Form Contract for Customer Retention rate.[11]

C. CONSIDERATION OF DG IN THE IRP PROCESS

In discussing its recommendation that utilities should be allowed to participate on a regulated basis in the customer-sited DG market, the CA stated that utilities should be allowed to participate in the "customer-sited DG market but their participation however, should be limited to those DG projects determined to be implemented from the Utilities' IRP plan". CA OB at 12. The CA clarified its statement concerning how DG projects should be identified in a utility's IRP process. The CA stated that not all DG projects can be identified through the IRP process,[12] DG projects should be incorporated in the aggregate in the IRP process,[13] and that it will likely not be reasonable to expect identification of all individual projects in the IRP process[14].[15]

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10 The HECO Companies' Rule 4 Standard Form Contracts for Customer Retention were designed to retain loads for recovery of fixed cost-related revenues, and not for the purpose of retaining specific customers. The basis for the contracts was provided in Docket No. 99-0106 for HECO, and Docket No. 99-0177 for HELCO. Rule 4 Contracts for Customer retention provide specified rate discounts for Schedules J, P, PS, PP, and PT customers who have viable alternate energy suppliers other than the HECO Companies. The energy rate discounts offered under the Rule 4 Rate Contract were set at amounts less than or equal to the percentage "subsidy" borne by the rate class (HECO and HELCO's Schedules J and P). Thus, even with the discount, the rates under the Rule 4 Rate Contract were still well above marginal costs. HECO Companies' OB at 133.

11 MECO does have a service contract with Castle & Cooke, LLC, which was filed and approved in Docket No. 03-0261. However, the terms of MECO's service contract with Castle & Cooke were the result of negotiations between the parties, and MECO does not have a Rule 4 Contract for Customer Retention. See HECO Companies' OB at 134.

12 CA OB at 16-17 ("the IRP process as set forth in the Framework is the proper forum for the purpose of analyzing and determining utility and customer DG perspectives, to the extent possible since not all customer-sited DG can be done through the utility's IRP").

13 CA OB at 20 ("non-utility DG should be incorporated in the aggregate in the IRP process, the same manner that utility owned DG should be recognized in the IRP process").

14 CA OB at 26 ("While it will not likely be reasonable to expect identification of all individual projects or perhaps accurately identify project zones in the IRP process, the IRP process should

By its nature, DG is difficult to analyze in the IRP process. The IRP process analyzes resources at the system level prior to the identification of specific projects. In addition, an individual DG project is generally too small to impact the timing of central station units or transmission line timing. For these reasons, DG must be considered on a generic basis in the IRP process without consideration of the specific impacts a particular project may have on the system that are site specific. In order to complete a fair evaluation, an aggregate forecast of DG resources must be developed, as was done for CHP system in the analysis done for the CHP Program application in Docket No. 03-0366. HECO Companies' OB at 137.

Even if not specifically identified in the integrated resource plan, other DG and CHP projects can still be pursued. Because CHP projects are largely driven by customer need, it is difficult, if not impossible, for the HECO Companies to identify all potential CHP projects. Therefore, after HECO's IRP-3 preferred plan and five-year action plans have been finalized and filed with the Commission, new CHP or DG opportunities not identified in the resource plan or action plan may arise. HECO should not be precluded from pursuing these opportunities. HECO Companies' OB at 138.

COM erroneously contends that "HECO does not assess the provision of grid system benefits from privately owned CHP DSM in its IRP . . . ." COM OB at 15.[16] The impact of CHP will be considered independent of ownership. The impact of utility and non-utility CHP will be treated equally.

As discussed in the HECO Companies' Opening Brief (pages 137 to 142), within the

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include a reasonable expectation as to the aggregate forecasts of DG resources in order to develop the lowest reasonable cost plan for providing reliable service and in order to complete a fair evaluation of the benefits and impact of DG").

15 The CA's recommendations concerning the type of information that should be included in a utility's five-year action plan (CA OB at 17-18) are beyond the scope of this proceeding and should not be considered. The CA's recommendations are more appropriately raised in an IRP proceeding.

16 As discussed in this Reply Brief, it is incorrect to consider DSM as a form of DG.

overall IRP process, DG/CHP will be evaluated from the generation capacity planning, transmission planning and transmission and distribution planning perspective to the extent practical.[17]

With respect to generation capacity planning, the IRP process will determine the need for new generating capacity based on a forecast of future electrical demand, the extent to which that demand can be reduced through demand-side management programs, and the extent to which the need for reserve capacity can be reduced through load management programs. Once that need is determined, the HECO Companies will evaluate various options to satisfy that need. Those options include DG, CHP, renewable energy and central-station generation. HECO Companies' OB at 137-38.

The HECO Companies plan to perform two separate evaluations of CHP in the HECO IRP-3 process, which is currently in progress. The first evaluation will be performed as part of the main integration effort, where long-term resource plans are developed from combinations of demand-side and supply-side resources. The plans will consider two levels of CHP market sizes: (1) the Companies' best estimate of the CHP market level and (2) a high or optimistic CHP market level. <u>The analysis will be performed independent of ownership</u>. <u>The market sizes will take into account the total of non-utility and utility CHP</u>. The integration analysis will determine the impact of each market size on the selection and timing of demand-side and supply-side resources for each finalist resource plan. In order to simplify this analysis, CHP costs (capital, O&M, or fuel) and CHP revenue impacts in the calculation of total resource costs for each of the finalist resource plans will not be included. Instead, the first analysis will focus on how different CHP market sizes affects the timing and types of resources selected for the candidate resource

[17] The HECO Companies have focused their analysis of DG in IRP on CHP because the Companies foresee a substantial customer demand for this technology. To this extent, the estimated market potential could affect the Companies' resource decisions.

plans. See HECO Companies' OB, Exhibit "A" at 6-7.

The second evaluation the HECO Companies plan to perform is a supplemental analysis to demonstrate the impacts of CHP ownership (utility versus non-utility) on total resource costs and utility revenue requirements. This second evaluation will focus on the impact to ratepayers resulting from CHP resources as a function of CHP ownership. This evaluation will be limited to impacts to one resource plan – the utility's preferred resource plan. See HECO Companies' OB, Exhibit "A" at 7.

In addition, within the IRP process, the impact of DG/CHP on the transmission system may be given limited consideration (in a few finalist plans). System-level forecasts of DG/CHP can be allocated down to the transmission substation level to identify the potential impact of DG/CHP on the timing and location of transmission planning criteria violations. It is not practical to consider DG/CHP impacts in the IRP process with respect to distribution planning. The distribution planning process involves smaller geographic areas and a shorter planning horizon compared to transmission planning. See HECO Companies' OB, Exhibit "A" at 7-8.

D. RATE DESIGN AND COST ALLOCATION ISSUES

1. Standby Rates

COM argues that the HECO Companies' proposal for standby charges for third-party owned DG units should not be accepted. Instead, COM contends that its "newest" standby rate proposal should be implemented. See COM OB at 28 - 33. COM has set forth several different standby rate proposals in this docket. COM presented different standby rate proposals in its Direct Testimony and Rebuttal Testimony, and now, COM has proposed yet another standby rate design in its Opening Brief. See COM OB at 30-37; COM RT-2 at 16-25; COM DT-2 at 16-35. COM's latest proposal should not be considered as the parties have not had an opportunity to ask information requests and to cross-examine COM on its latest proposal.

The record before the Commission is not complete enough for the Commission to mandate either the form of future standby rates, or the costs to be recovered in the standby rate components. This can best be done in a follow-up proceeding, which should be in the form of a contested case framework proceeding, such as the Integrated Resource Planning Framework docket (so that the result will be supported by reliable, probative and substantive evidence), rather than a rulemaking proceeding. The actual standby rate schedules would then be implemented in rate case or separate tariff filings. In the meantime, the utilities should be allowed to propose interim, voluntary standby rates. Moreover, the conduct of such a follow-up proceeding should not further delay the implementation of utility CHP service.

With respect to rate design, the appropriate goal is to implement cost-based rates for all customers, including DG customers. The existing rates for backup and supplemental service charged to customers who install their own or third-party DG/CHP systems are not unfair, and may under-recover fixed costs from such customers. This under-recovery was addressed in substantial part on the Big Island, where the under-recovery was most pronounced, through the implementation of the CA-stipulated, Commission-approved Standby Rider A. Nonetheless, the HECO Companies recognize that it will be appropriate to implement cost-based standby rates for HECO and MECO,[18] as well as for HELCO, and that the HELCO standby rider can be improved.

Dr. Gegax, the HECO Companies' consultant on this issue, pointed out that the appropriate rate design to accommodate the special nature of customer-owned generation differs from the rate design for full-requirements customers. The rates, in part, must be based on

[18] This will become more important if existing rates and costs are more closely aligned, as recommended by the HECO Companies.

reserved capacity requirements of the DG customer to ensure that the customer can be accommodated when the DG facility is unavailable. To cover the costs related to standby service, customers that own DG, but remain connected to the utility's network, may require an adjustment to their existing tariffs. As a result, other jurisdictions (including those with unbundled rates) have implemented this special rate design through a modification of the existing tariff (i.e., through a standby rate provision). HECO Companies' OB at 125-126.

Thus, the real issue is not whether cost-based standby rates should be implemented, but how to implement standby rates so that they <u>are</u> cost-based to the extent practical. In this regard, there is substantial disagreement as to what costs are attributable to DG customers. Moreover, the answer depends on the maximum amount of DG load that the HECO Companies must standby to serve (i.e., be ready to serve) at any given point in time - - and, thus, the answer should take into account the actual characteristics of the customer-sited DG load on the system (which will change over time). HECO Companies' OB at 126.

The utility system remains available <u>at all times</u> to make up the moment-to-moment difference between DG customers' electricity usage and the amount of electricity produced by their generation, and from time-to-time the utility will have to meet the <u>full</u> energy needs of various DG customers with utility-generated electricity. The distribution, transmission, and generation capacity built into the utility's system must be sufficient to meet this moment-to-moment variation in their demand as well as the DG customers' full demand when the customers' generation is not producing electricity. There are costs associated with this utility system capacity, which continue regardless of usage. These costs should be recovered from DG customers throughout the year, not only during the times when the customers actually use the capacity to deliver additional energy. Therefore, the appropriate design of rates for DG customers based on cost-causation principles would include a demand charge large enough to recover the full costs associated with the capacity necessary to meet the customer's full demand at any time. HECO Companies' OB at 126.

The utility's transmission and distribution system must be built and maintained to accommodate a DG customer's maximum load even if some of this load is generally satisfied by the customer's DG, to accommodate for the periods when the DG is unavailable. Most of the utility's cost of providing standby assurance is associated with the fixed costs of the transmission and distribution system, and a portion of the fixed costs of generation, as well as additional customer-related costs associated with any additional metering and billing. HECO Companies' OB at 127.

The full cost related to distribution capacity should be included in any standby reservation charge, because this capacity is necessary to fulfill the standby assurance benefiting the DG customer. While it can be argued that the full cost of transmission capacity falls in the same category, it can also be argued that a portion of the transmission capacity (the "bulk transmission" component) is sized based on the generation capacity. To the extent that this is the case, only a portion of the bulk transmission cost would have to be recovered from DG customers. HECO Companies' OB at 127.

Standby service rates should only include a portion of the fixed costs associated with generation. The utility's total investment in generation includes (1) capacity that is required to satisfy the expected demand of its customers, and (2) reserve capacity that is required for unexpected generation outages and other ancillary services necessary to ensure system reliability. HECO Companies OB at 127.

Full requirements customers are allocated their share of the costs related to both categories of generation capacity. The DG customer, on the other hand, has made an investment in generation capacity which, when available, satisfies a portion of its energy needs. Therefore, DG customers have self-provided the first category of generation capacity listed above in order to cover a portion of their load. DG customers, however, have not self-provided the capacity identified in the second category listed above. Therefore, the generation capacity cost attributable to DG customers includes an allocation of the utility's costs associated with the second category of generation capacity. HECO Companies' OB at 127-128.

The portion of the DG customer's load that is not satisfied through its DG capacity (which is generally termed "supplemental service") is subject to the rates in the existing tariff; that is, the rate elements that include the fully allocated cost of all utility functions provided by the utility. HECO Companies' OB at 128.

In addition, any costs associated with new facilities, such as metering and distribution system upgrades that may be required to accommodate DG, should be recovered from the DG customer for standby service. These costs may need to be determined on a case-by-case basis. Furthermore, variations in the type of technology employed across DGs can affect ancillary service requirements and, hence, utility system costs. Those costs would also have to be identified on a case-by-case basis. HECO Companies' OB at 128.

2. <u>HELCO's Standby Rider</u>

Hess erroneously contends that for the HELCO system, there should not be a standby charge because allegedly "customers are already being charged a ratcheted demand charge and thus, the standby charge results in the DG customer being double charged." Hess OB at 5 (footnote omitted).[19]

[19] The Hess OB (page 6 citing Tr. (12/9/04) at 250) quotes a portion of testimony at the panel hearing, concerning the alleged impact of HELCO's Standby Rider on the installation of CHP systems, which

Under HELCO's Commission-approved Standby Rider, a customer's supplemental billing demand (i.e., its Supplemental Billing kW), which is billed under the regular rate schedule, is based on the difference between the customer's highest Total kW Load for the month, and the Standby Billing kW (which is fixed by the Standby Service Contract, generally based on the capacity of the on-site generation). The Total kW Load for each month is the maximum time-coincident sum of the measured kW Load supplied by HELCO and the measured kW Load supplied by the customer's on-site generation. If, however, HELCO cannot meter the total output of the on-site generation, then Rider A provides that the customer's Total kW Load will be the sum of the measured kW Load supplied by HELCO and the Standby Billing kW.

The standby service tariff (Rider A) contemplates that a utility meter will be installed, at the customer's expense, to meter the kW and kWh output of the customers' on-site generator(s). (The customer would install the meter socket or sockets. HELCO would install its meters in the sockets.) Metering of the customer's on-site generation is necessary to differentiate between supplemental service (for which a demand charge is applied under the regular rate schedule (i.e., Schedule J or P)), and backup service (for which a demand charge is applied under Rider A).

HELCO has not been able to install meters to measure the electrical output of the CHP units for a number of customers, as is required by the standby service rider. As a result, HELCO has not been able to meter the output of the customers' onsite generation for customers receiving standby service. HELCO is able to charge for standby service under Rider A even when the meter(s) for the on-site generation is not installed, but the customer generally incurs a higher supplemental billing demand (which impacts its demand charge under the regular rate schedule) than it would if the meter(s) for the on-site generation was installed.

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the transcript erroneously attributed to the CA's witness, Mr. Joseph Herz. In actuality, the statement quoted by Hess was made by COM's witness, Mr. Jim Lazar.

Hess also commented that the HELCO-CA stipulated Standby Rider which was approved by the Commission was made without having all of the information necessary to determine the standby charge. Hess OB at 6. One piece of information that HELCO did not have, and which HELCO had to presume for purposes of the standby charge, was that there would be a certain level of diversity among the standby customers. In other words, even though HELCO did not have any evidence that there would be diversity among the DG customers, for purposes of determining the standby charge, a certain level of diversity was presumed which resulted in a lower standby charge.

3. COM's Diversity Argument

COM alleges that there is an "implication by HECO that every DG system requires a utility backup of equal capacity. In fact, a well developed DG industry, with as many as 100 installations per island, would allow for many DG customers to share a unit of standby capacity." See COM OB at 26-28.

COM's allegation is without merit as there is no "implication" that the HECO Companies require a utility backup of equal capacity for each DG system. In fact, the HECO Companies assumed in their evaluation of their proposed CHP Program that they would need to provide backup capacity for only a portion of the aggregate amount of total DG (in the form of CHP) capacity installed on their systems. In the HECO Companies' evaluation of the cost-effectiveness of their proposed CHP Program, the HECO Companies compared the costs of the CHP Program against the benefits of the proposed program. Exhibit H, page 4, of the CHP Application shows the central-station unit timing without and with utility CHP. In the Base Plan without utility CHP, it was assumed that all CHP would be installed by third parties. In this case, it was assumed that system demand would be reduced by 91% of the aggregate capacity of the amount of third-party CHP installed. In other words, the HECO Companies would need to provide backup capacity to only 9% of the aggregate capacity of the amount of third-party CHP installed. A similar assumption was made for the Alternate Plan with utility CHP. Only 91% of the aggregate amount of utility CHP was counted as firm capacity, and only 9% of non-utility CHP would need to be backed up by the utility.[20] These were simplifying assumptions made for the purpose of the cost-effectiveness analysis.[21] Actual operating experience of many CHP systems will be needed to determine the appropriate value to use to represent the "diversity" of CHP or DG on the grid and this value may change over time. See e.g., HECO T-3 at 9-10, HECO response to COM-HECO-DT-IR-19. The HECO Companies also recognized that diversity on distribution circuits could reduce the need for distribution capacity. HECO response to COM-Companies-SOP-IR-3.

In addition, COM's discussion of diversity is not based on actual current conditions as each of the HECO Companies do not have a large number of DG customers (COM referenced 20 and 100 DG customers in its discussion of diversity). COM OB at 26 n.20. The HECO Companies illustrated in the cross examination of one of COM's witnesses that when there are only a few DG units installed on a system (as is currently the case for each of the HECO Companies) that it was incorrect to rely on the forced outage rate of one of the DG units to determine the amount of capacity that is needed to backup the DG units. See Tr. (12/10/04) at 67-70 (cross-examination of Lazar).

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20 Exhibit A to the CHP Program Application discussed the assumption concerning the number of CHP systems assumed to be installed for purposes of the cost-effectiveness analysis.

21 The 91% availability value used for the cost-effectiveness analysis included an estimate of scheduled outages (maintenance) and unscheduled outages. The cost-effectiveness analysis assumed utility central-station backup for scheduled maintenance because: (1) 3rd party CHP installations have no obligation to schedule their maintenance with the utility, (2) of a lack of flexibility to schedule maintenance as much of the maintenance requirements for CHP systems are triggered by run-hours and fixed service intervals, and (3) with a substantial number of CHP installations, it would be difficult to manage the scheduling of utility and 3rd party CHP outages with the utility's central-station generating unit outage schedules and with each other.

4. **Impact Fees**

COM recommends that MECO implement connection charges (or impact fees) for new customers and expanded loads. COM claims that the addition of new customers results in existing power plants being augmented by newer, more expensive units. COM OB at 34-42.[22]

An impact fee requires the implementation of an up-front charge on new or expanding customers to cover the installed facilities and equipment cost of generation and transmission capacity. COM proposes to establish this generation impact fee for new and expanded loads to recover the cost of future new power plants. Specifically, COM proposes a generation impact fee of $2,000 per kW of the new customer's connected load. COM OB at 40. The COM proposal extends to all customers – both residential and non-residential. COM's proposal results in a generation impact fee of $10,000 for a typical new residential customer, based on a residential customer's typical connected load of approximately 5 kW. HECO Companies' OB, Exhibit "D" at 1.

The HECO Companies should not be required to charge an impact fee (i.e., a non-refundable contribution in aid of construction) to only those new customers who are adding load to the system for the capital costs of new generating facilities (or for the incremental cost over the embedded capital costs of existing generation).

COM cites rising capacity costs as justification for such a policy and references the Commission's approved line extension policy as an example of how this is already done. This proposal is highly inconsistent with sound utility economics because it would create a new sub-class of customers within each existing class based on vintage of the customer.

In Hawaii, electricity customers generally are not charged differential rates based on their

[22] As discussed in the HECO Companies' Opening Brief, in general, COM's rate proposals should not be considered at this time.

vintage, and members of a customer class are treated equally. The HECO Companies' line extension policy currently includes a form of connection charge. However, there is a fundamental difference between the facilities covered by the line extension policy and the facilities associated with generation and transmission. Unlike line extensions, which involve distribution facilities that are dedicated to serve a particular customer or a distinguishable set of customers, generation and transmission facilities are used in common by all customers on the system. "Dissecting" facilities that clearly benefit the system as a whole based on individual customer vintage is inconsistent with proper allocation of shared network costs and discriminatory. HECO Companies' OB, Exhibit "D" at 2.

In addition, imposing an impact fee on new or expanding customers would create new sub-classes of customers based on vintage. This would require the Commission and the utility to implement detailed accounting for the amounts collected from new customers and distinguish between capacity additions caused by growth versus capacity additions that are necessary to replace existing capacity. Even if the Commission establishes such accounting rules, the costs per unit of generation and/or transmission capacity can be expected to change through time. They can increase or decrease depending on the current cost of equipment and possible technological innovation. HECO Companies' OB, Exhibit "D" at 3.

The implementation and management of such a policy would be extremely burdensome on the regulatory process, if not unmanageable.[23] See HECO Companies' OB, Exhibit "D" at 3-4. Further, COM makes a simplifying assumption that only new customers or existing customers with large renovations are responsible for load growth. However, existing customers,

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23 There would be significant difficulties in structuring the rates for new customers if they were required to pay an impact fee covering the cost of new generation and transmission facilities or the incremental cost above and beyond the average embedded cost of existing generation and transmission facilities. Existing rates include the average embedded cost of existing generation and transmission facilities. See HECO Companies' OB, Exhibit "D", at 3-4.

most of whom did not make large renovations, accounted for nearly half of the load growth on the island of Maui in 2003. Therefore, COM's proposal to allocate all of the marginal cost of new facilities to these new or expanding load customers is patently inequitable. New customers are only responsible for slightly more than half of the load increase, but would pay the entire marginal cost of new facilities under COM's proposal. HECO Companies' OB, Exhibit "D" at 6-7.

Moreover, inherent in COM's discussion of generation capacity is the erroneous assumption that all capacity is of the same type and designed for the same purpose. In reality, the optimal mix of generation capacity types and the decision to add capacity to that mix depend on current system load characteristics. To begin distinguishing "new" capacity from "old" capacity is contrary to the economics associated with an optimal mix of generation. The impact fee proposed by COM would hold new customers responsible for that new capacity despite the fact that its addition is optimal for the system as a whole. HECO Companies OB, Exhibit "D" at 7.

The HECO Companies are unaware of any investor-owned electric utility that has implemented a rate design similar to that proposed by COM. Moreover, COM was unable to identify any utility that currently charges generation impact fees similar to those it proposes. HECO Companies' OB, Exhibit "D" at 8.

COM supports its position on impact fees by noting that the addition of new generation tends to put upward pressure on rates. The premise is correct at least with respect to base rates, but COM's conclusion is not justified by the premise. The capital cost of new generating capacity exceeds the average depreciated capital cost of existing generating facilities that are in rate base. Thus, additions of new generating plant to rate base tend to cause upward base rate pressure, at least initially, although that is due in part to the manner in which rates are set. Plant generally is added to serve future load growth (i.e., in anticipation of need), not load growth that has already occurred. Other factors, such as increases in O&M expense (for which all customers are responsible), contribute to the ultimate need for a rate increase, but may not trigger an immediate rate increase because the contribution of increased sales to fixed costs (largely from new customers) delays the need for a rate case. (HECO's load and sales grew substantially from 1995 through 2003 without the filing of a rate case.) HECO Companies' OB, Exhibit "D" at 5.

It should be noted, however, that Maalaea Unit M19 was installed in September 2000 and MECO has not increased its base rates. In addition, rates are based on all costs, and not just rate base. In some cases, new generation may have lower fuel costs. Thus, a base rate increase could be triggered by the addition of the new capacity, but may not be indicative of the net rate impact on customers of adding the new capacity. HECO Companies' OB, Exhibit "D" at 5-6.

COM refers to the estimated cost of MECO's next generating unit, M18, and the estimated cost of the first combustion turbine ("CT") that might be added at the Waena site, as support for its position that the higher costs of new generation warrant impact fees. However, the costs cited by COM are misleading unless the context in which they will be incurred is added. M18 will include the addition of a heat recovery steam generator and a steam turbine generator, and will allow M17 and M19 to be converted into an efficient dual-train combined cycle unit with lower fuel costs. The estimated cost for Waena Unit 1 (a nominal 20 MW simple cycle CT), including escalation and AFUDC, is $70.5 million in 2010 dollars. However, this estimate includes the cost of combustion turbine spare parts, a 1 MW black start diesel engine, an Uninterruptible Power Supply, a spare water treatment train, and redundant water and fuel pumps. Also, the Waena CT has the capability to be included in an efficient combined-cycle unit in the future, and its consideration for the next central station unit for MECO's system would take into account this potential. HECO Companies' OB, Exhibit "D" at 6.

E. OTHER MATTERS

1. Definition Of DG Should Not Include DER Or Other Demand-Side Technologies Or Systems

COM contended that demand-side technologies or systems be treated like demand-side measures that are included in demand-side management ("DSM") programs, and that the utilities pay incentives to customers to install such measures. COM OB at 5-7.[24]

DG is a supply-side resource, not a demand-side resource. "Distributed generation" should refer to generation technologies only, in other words resources that supply energy. DG is broadly understood to be a subset of distributed energy resources ("DER"). Other DER subsets, such as DSM and energy storage technologies, are not DG. HECO Companies' OB at 59.

DG should not be confused as a DSM measure. Extensive testimony was provided to explain why DG is not similar to DSM measures or programs. DSM Programs are designed to influence the use of energy. DG is a resource that supplies energy. The distinction between the use and supply of energy was made by the Commission in its Framework for Integrated Resource Planning (Decision and Order No. 11630, Docket No. 6617). The HECO Companies maintain that the inclusion of the word "uses" in the IRP Framework implies that the framework intended to apply the term "DSM" only to those measures that affect how companies use energy, not how it is generated. HECO Companies' OB at 59-60.

The HECO Companies' Opening Brief discussed (1) the differences between DSM measures and DG resources in terms of ownership, operation and maintenance (page 60), and

24 The portion of COM's OB that discusses the basis for Mr. Kobayashi's testimony on DG (pages 43-45) should be disregarded. This material should have been included in COM's written testimonies and/or responses to information requests and not presented for the first time in COM's OB. Presenting the material for the first time in an Opening Brief prevented the parties from asking information requests and cross-examining Mr. Kobayashi on these matters.

(2) the major differences between the HECO Companies' proposed CHP Program and their DSM programs, such as the Residential Efficient Water Heating Program, which provides incentives to customers who install solar systems (pages 60-62).

Further, the HECO Companies' Opening Brief discussed that unlike the HECO Companies' proposed CHP Program, DSM programs are not currently designed so as to avoid any "burden" on non-participants. Incentives are paid to customers for "cost effective" programs, even where individual customer rates are increased when the utility recovers the program costs and lost contributions to fixed utility costs. (On a total customer basis, however, energy bills should be reduced because of the reduction in energy use.) Whereas all customers benefit from the demand savings (i.e., the kw savings) resulting from DSM program measures, participating customers are the primary beneficiaries of the energy savings. (At the same time, there is a benefit to the State as a whole, including non-participating customers, due to the reduction in the use of oil.) HECO Companies' OB at 62.

As is indicated above, one of the primary justifications for the current approach to DSM programs is that there is a broad array of DSM measures available under the DSM programs, and a broad opportunity for customers to participate (and to directly benefit from bill savings). HECO Companies' OB at 62.

In the case of CHP systems, all customers will benefit from the capacity deferral benefits that can be obtained from the installation, operation and maintenance of energy-efficient CHP systems, but only a relatively small number of customers have the opportunity to directly achieve energy cost savings through the installation of such systems on their sites. Thus, unlike the case with DSM programs, one of the key objectives of the CHP program is to avoid burdening non-participating customers. HECO Companies' OB at 63.

2. **Costs And Benefits Of DG During Times Of Excess Capacity And Shortages Of Capacity**

COM alleges that when "conventional resources" (e.g., 20 MW combined cycle unit) are initially placed in service they create excess capacity and the system grows into the excess capacity over time. (COM refers to this phenomenon as "lumpiness".) COM alleges that DG can overcome the lumpiness factor due to the size of the units in comparison to "conventional resources". With these "boom and bust" cycles COM alleges that consumers "lose almost continuously" because allegedly the system has an optimally configured system for only a fleeting moment. See COM OB at 9-11.

The HECO Companies performed an extensive economic analysis in support of their CHP Program application in Docket No. 03-0366, considering all the numerous revenue and cost impacts, to show that the HECO Companies' ratepayers as a whole are better off with utility participation. This analysis showed a positive net present value benefit for all of the Companies, indicating the CHP Program is expected to be cost-effective from a Utility Cost Test perspective. The HECO Companies' economic analysis methodology, assumptions, and results are explained in detail on pages 51 to 61 of the CHP Program application in Docket No. 03-0366, and were addressed by Mr. Sakuda in HECO T-3.[25] See HECO Companies' OB at 67-69.

II. CONCLUSION

Based on the foregoing, the discussion in the HECO Companies' Opening Brief of the issues, and the reliable, probative and substantial evidence in the record in this proceeding, the HECO Companies respectfully request that the Commission expeditiously authorize them to

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25 In the Rule 4 contract filings in Docket Nos. 04-0314 and 04-0366, HECO and HELCO indicated that various revisions needed to be made to this analysis such as updating heat rate assumptions and correcting an understatement of facility fee revenue. In light of HECO's current need for additional generation, and its expected inability to add central station generation before 2009, the updated analysis also should identify the method used to value the generation deferral benefit of CHP in the 2006-2009 timeframe. See HECO Companies' OB at 67-68.

proceed with the installation of utility-owned, operated and maintained CHP systems at customer sites (pursuant to Rule 4 CHP Agreements and their proposed CHP Program), subject to the conditions proposed in Section I of the HECO Companies' Opening Brief.

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THOMAS W. WILLIAMS, JR.
PETER Y. KIKUTA

Attorneys for
HAWAIIAN ELECTRIC COMPANY, INC.
HAWAII ELECTRIC LIGHT COMPANY, INC.
MAUI ELECTRIC COMPANY, LIMITED

CERTIFICATE OF SERVICE

I hereby certify that I have this date served a copy of the foregoing **REPLY BRIEF,** together with this Certificate of Service, by making personal delivery or by causing a copy hereof to be mailed, postage prepaid and properly addressed, to each such party:

DEPARTMENT OF COMMERCE AND CONSUMER AFFAIRS 3 copies
DIVISION OF CONSUMER ADVOCACY
335 Merchant Street, Room 326
Honolulu, HI 96813

H. A. Dutch Achenbach
Kauai Island Utility Cooperative
4463 Pahe'e Street
Lihue, HI 96766

Oshima Chun Fong & Chung LLP
Kent D. Morihara, Esq.
541 Bishop Street, Suite 400
Honolulu, Hawaii 96813

Attorneys for Kauai Island Utility Cooperative

Warren S. Bollmeier II
President
Hawaii Renewable Energy Alliance
46-040 Konane Place #3816
Kaneohe, Hawaii 96744

John Crouch
Box 38-4276
Waikoloa, Hawaii 96738

Rick Reed
Interisland Solar Supply
761 Ahua Street
Honolulu, Hawaii 96819

Brian T. Moto, Esq.
Cindy Y. Young, Esq.
Department of the Corporation Counsel, County of Maui
200 S. High Street
Wailuku, Hawaii 96793

Kalvin K. Kobayashi
Energy Coordinator
County of Maui
Department of Management
200 S. High Street
Wailuku, Hawaii 96793

Henry Q Curtis
Vice President for Consumer Issues
Life of the Land
76 North King Street, Suite 203
Honolulu, Hawaii 96817

Lani D. H. Nakazawa, Esq.
Christiane L. Nakea, Esq.
Office of the County Attorney
County of Kauai
4444 Rice Street, Suite 220
Lihue, Hawaii 96766

Glenn Sato
Energy Coordinator
c/o Office of the County Attorney
County of Kauai
4444 Rice Street, Suite 220
Lihue, Hawaii 96766

Christopher S. Coleman, Esq.
Deputy Attorney General
Amerada Hess Corporation
One Hess Plaza
Woodbridge, New Jersey 07095

Michael De'Marsi
Hess Microgen LLC
4101 Halburton Road
Raleigh, North Carolina 27614

Hess Microgen, LLC
c/o Sandra-Ann Y.H. Wong, Esq.
Attorney at Law, a Law Corporation
1050 Bishop Street, #514
Honolulu, Hawaii 96813

DATED: Honolulu, Hawaii, March 28, 2005

THOMAS W. WILLIAMS, JR.
PETER Y. KIKUTA

Attorneys for
HAWAIIAN ELECTRIC COMPANY, INC.
HAWAII ELECTRIC LIGHT COMPANY, INC.
MAUI ELECTRIC COMPANY, LIMITED