HECO RT-1
DOCKET NO. 03-0371

REBUTTAL TESTIMONY OF

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HAWAIIAN ELECTRIC COMPANY, INC.

Subjects:
Generic Benefits of Distributed Generation ("DG");
DG Applications and Ownership Options;
Companies' Plans For DG;
Distinction Between Utility and Non-Utility Combined Heat and Power;
Utility Ownership of Customer-Sited DG
Customer Preference and Support for Utility-Owned DG;
DG Not Similar to Demand-Side Management Measures/Programs;
Impact Fees Not Appropriate; and
Final Comments: Objective of Competition

INTRODUCTION

Q. Please state your name and business address.

A. My name is Scott W. H. Seu. My business address is P.O. Box 2750, Honolulu, Hawaii 96840.

Q. What is your present position with Hawaiian Electric Company, Inc. ("HECO")?

A. I am Manager of HECO's Energy Projects Department.

Q. Mr. Seu, have you previously testified in Docket No. 03-0371?

A. Yes, my written direct testimony, HECO T-1, covered the following topics: Distributed Generation ("DG") Application and Technologies, HECO Consideration of DG, HECO Participation in Combined Heat and Power ("CHP"), Hawaii CHP Market, Customer Support for HECO CHP Involvement, Impact on Competition, Current HECO CHP Activities, Externalities, and Integrated Resource Planning ("IRP").

Q. What subject will you cover in your rebuttal testimony?

A. I will present testimony supporting HECO's broad position that the electric utility should be allowed to own distributed generation, including CHP, at customer sites. Specifically, I will discuss the following:

1) Generic benefits of DG;
2) DG Applications and Ownership Options;
3) The Companies' Plans For DG;
4) The Distinction Between Utility and Non-Utility CHP: General;
5) The Distinction Between Utility and Non-Utility CHP: Economic and Rate

Impacts;

6) The Distinction Between Utility and Non-Utility CHP: Operations and Maintenance ("O&M");

7) The Distinction Between Utility and Non-Utility CHP: Effect on CHP Market Size;

8) The Distinction Between Utility and Non-Utility CHP: Summary;

9) Utility Ownership of Customer-Sited DG: Impact on Competition;

10) Utility Ownership of Customer-Sited DG: Authority;

11) Customer Preference and Support for Utility-Owned DG Cannot be Ignored;

12) DG is not Similar to Demand Side Management ("DSM") Measures/Programs;

13) Impact Fees are Not Appropriate; and

14) Final Comments: The Ultimate Objective of Competition is to Benefit Consumers, not Competitors.

Q. What other rebuttal testimonies do the Companies present in this proceeding?

A. In addition to myself, there are six witnesses supporting the Companies' position. The witnesses and the nature of their testimonies are as follows:

HECO RT-2	A. S. Seki
Testimony	Utility Support for Renewable Energy Development; and Summary and Update of Policies and Incentives for Renewable Energy Development
HECO RT-3	R. H. Sakuda
Testimony	Need for Utility Combined Heat and Power Capacity, Virtual Power Plant Concept, and Distributed Generation/Combined

	Heat and Power and Integrated Resource Planning
HECO RT-4	S. Y. Ishikawa
Testimony	Impact of DG on the Reliability of the T&D System, Conceptual Overview of T&D Avoided Cost Calculation, and the Impact of DG on the Power Quality of the T&D System and DG Interconnections
HECO RT-5	E. A. Seese
Testimony	Rate Design
HECO RT-5A	D. A. Gegax
Testimony	Consultant on Behalf of Hawaiian Electric Company, Inc. on Rate Design Issues
HECO RT-6	W. A. Bonnet
Testimony	Regulatory Policy Matters

Q. Who do you represent in this submittal of testimonies and exhibits?

A. The testimonies submitted represent the positions of HECO, HELCO and MECO. For convenience, our testimonies and exhibits are marked as "HECO". Throughout this submittal, when we refer to HECO, HELCO and MECO together, we refer to them either as "HECO" or the "Companies". Where it is important to distinguish between the Companies or the Islands, we have identified the particular company or island.

GENERIC BENEFITS OF DG

Q. What are the generic benefits of DG to the electric utility?

A. From a generic standpoint, reliable DG in sufficient quantities and appropriate locations can provide the following benefits to the Companies:

1) Deferral of new central station generating capacity;

2) Displacement of utility central station generation fuel and variable O&M costs;

3) Deferral of new transmission and distribution ("T&D") capacity; and

4) Improved T&D system reliability and power quality.

These are benefits from a generic point of view. Individual DG installations will have their case-specific impacts, both positive and negative.

Q. Are there any other ratepayer benefits other than those associated with the avoided generation and T&D capacity?

A. Yes. To the extent that the utilities are allowed to own customer-sited DG and a customer chooses the utility-owned DG system over a self-owned or third party-owned system, the utility and its ratepayers will generally benefit by retaining the customer load and avoiding uneconomic bypass.

DG APPLICATIONS AND OWNERSHIP OPTIONS

Q. Please describe how DG can be applied in Hawaii, and what the ownership options are.

A. As described on page 12 of HECO T-1, DG uses in Hawaii and their ownership options are:

1) Customer-sited emergency generation: Generally owned by customers, although utilities offer a utility-ownership option in a few jurisdictions;

2) Substation-sited peaking generation: owned by utilities;

3) Substation-sited generation to address case-specific transmission and/or

distribution ("T&D") problems: Owned by utilities;

4) Customer-sited CHP: May be owned by customers, third-party vendors/equipment lessors, or utilities;

5) Customer-sited cogeneration: Generally owned by customers or independent power producers, although utilities may consider owning certain facilities or having a partial or indirect ownership interest in such cogeneration;

6) Off-grid, customer-sited generation: Generally owned by customers; and

7) Customer-sited generation operated in parallel with the utility grid: May be owned by customers or third-party vendors/equipment lessors or by utilities (if such ownership is a cost-effective utility option).

Q. What are the operations and maintenance ("O&M") options?

A. Where the customer owns the DG, or acquires the DG through an equipment lease, the customer generally is responsible for O&M, or can contract O&M to a third-party vendor. Where a third-party vendor owns the DG, the third-party vendor generally would be responsible for O&M, unless the vendor subcontracts that responsibility to a third-party service provider, or the vendor's contract with the customer allocate some or all of the responsibility to the customer.

THE COMPANIES' PLANS FOR DG

Q. Considering the seven applications of DG described above, which of these are being pursued by HECO?

A. The Companies' plans with respect to the seven DG applications were described on pages 13 and 14 of HECO T-1, and are as follows:

1) Customer-sited emergency generation: The Companies do not currently anticipate providing such a service. (See Response to CA-SOP-IR-12.) A few utilities have offered to provide emergency generators under a tariff program, with or without reserving the right to operate the "emergency" generators for peaking purposes when the utility is short of capacity. However, there are a number of practical issues with trying to use emergency generators for peaking purposes. (See Response to HREA-HECO-IR-9.)

2) Substation-sited peaking generation: The Companies intend to use DG for this purpose under appropriate circumstances, as was done with HELCO's four 1-MW dispersed generators.

3) Substation-sited generation to address case-specific T&D problems: The Companies intend to use DG for this purpose under appropriate circumstances, as was done with MECO's Hana generators.

4) Customer-sited CHP systems: The Companies' current focus with DG is to offer such CHP systems, subject to Commission approval, under circumstances where it is cost-effective for the utilities to do so, and offering such a service does not unduly burden non-participating customers.

5) Customer-sited cogeneration: The Companies do not intend to offer such systems, but would consider DG for this purpose on a case-by-case basis.

The Companies would consider owning and operating an industrial customer-sited cogeneration facility that sells electricity and process steam to the industrial host, and that delivers electricity in excess of the host's requirements to the utility. Generally, however, such a project should be considered outside the scope of this proceeding given the probable size of such a facility and the transmission of electricity from the facility to the utility's grid.

6) Off-grid, customer-sited generation: The Companies do not intend to offer such a service.

7) Customer-sited generation for power purposes only: The Companies do not intend to offer such systems, but would consider DG for this purpose on a case-by-case basis if such an application becomes a cost-effective utility option.

Q. Why are the Companies focused on CHP?

A. Of all the DG technologies and applications, HECO's programmatic focus is on CHP due to its broad array of customer and system benefits, although the Company plans to use other forms of DG on a case-by-case basis as described above. The CHP that is of interest are those projects that are effective in terms of providing benefit to both the CHP host customer and the broader ratepayers and system. The utility is generally not interested in pursuing CHP where it does not fit the parameters of its proposed CHP Program. (See response to HREA-HECO-T-1-IR-22)

DISTINCTION BETWEEN UTILITY AND NON-UTILITY CHP: GENERAL

Q. Why is HECO focused on offering CHP to customers as a utility service?

A. The Companies see a customer demand and at the same time a broader role for CHP in its overall electric system, based on the potential system benefits of DG described earlier.

The reasons for, and the benefits of, utility participation in the provision of CHP systems were cited on pages 15 and 16 of HECO T-1 and are repeated as follows:

1) The provision of CHP services by utilities is a natural step in the evolution of electric utility services, and electric utility customers should have the option of acquiring CHP systems from Hawaii utilities.

2) The installation of cost-effective, energy-efficient CHP systems should further the objectives of Hawaii's State energy policy and assist the Companies in meeting their utility Renewable Portfolio Standards ("RPS").

3) Development of the CHP market may generate enough capacity to help defer the need for new central station generation.

4) CHP systems strategically located and reliably operated may potentially defer the need for transmission and distribution system upgrades.

5) The utilities' provision of CHP systems on a regulated basis will ensure that the interests of all customers are taken into consideration. Benefits should be available to the customers for whom DG/CHP is a viable option, but the

interests of other non-participants should be protected. The independent implementation of DG/CHP results in a loss of revenue to the utility and all customers are then ultimately adversely impacted by the lack of contribution to fixed costs from the customers that implemented third-party DG/CHP.

6) Utility participation in the CHP market provides the utility customers with one more option to meet their energy needs – in the words of one customer; it means "one stop shopping". Customers want to focus on what they do best and let the utility do what it does best: (a) own, operate and maintain power facilities; (b) manage fuel procurement for power facilities; and (c) manage electrical system interface.

7) Utility involvement in CHP will result in an overall larger CHP market in Hawaii, due to customer support and the uniqueness of the Companies' offering.

Q. Regarding CHP as being a natural step in the evolution of the Companies' services, what has been alleged by the County of Maui ("COM")?

A. The COM alleges that CHP is a non-monopoly service, and therefore questions why it is natural for the utility to provide CHP. This allegation fails to consider that the Companies have used DG sited at substations to address transmission and generation capacity requirements. As utilities, they have long been in the business of installing, operating, and maintaining generating units, and the electric utility can readily apply this experience to customer-sited CHP systems. Moreover, to the extent that the CHP systems can play a broader role in the utility electrical system, it is even more natural for the utility to be directly involved in developing and owning CHP. (See response to COM-HECO-DT-IR-53)

Q. What is so unique about the Companies' CHP offering?

A. The uniqueness of the Companies' CHP offering is to provide a complete utility-owned, operated, and maintained CHP unit to the customer. Customers have responded well to such a model as it relieves them of the responsibilities of owning, operating, and maintaining the CHP equipment themselves, or subcontracting those responsibilities out. While other CHP developers have offered and may continue to offer third-party system ownership benefits to customers, the general trend has been for the CHP equipment vendors and energy service companies to move away from the model of owning equipment at a customer site. In addition, utility-owned CHP would be subject to oversight by the Public Utilities Commission, and this provides reassurance to CHP customers that the CHP systems will be properly designed, operated, and maintained. (See response to COM-HECO-DT-IR-3)

DISTINCTION BETWEEN UTILITY AND NON-UTILITY CHP: ECONOMIC AND RATE IMPACTS

Q. What quantitative analysis has been done to show that the Companies' proposal to offer CHP should benefit all customers, unlike the case with non-utility CHP projects?

A. The Companies performed an extensive economic analysis in support of its CHP

Program application in Docket No. 03-0366 considering all the numerous revenue and cost impacts, to show that the 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 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 in HECO T-3.

The analysis took into account the revenues and costs resulting from doing a substantial number of CHP projects. Justification for CHP system projects can and should be shown on a programmatic basis, rather than on a project-by-project basis – as long as the terms and conditions under which the CHP system services are provided to customers are consistent with the assumptions underlying the quantitative analyses justifying the program.

Q. If a third party installed and owned the CHP instead of the utility, what would be the impact on ratepayers?

A. A third-party CHP system will cause the Company to lose revenue based on the reduction in demand and energy charges. The energy charge recovers a substantial percentage of the Company's fixed demand and customer costs, and the lost revenues far exceed any savings the Company will see in variable operating and maintenance costs associated with the customer's reduction in load and energy. Per the analysis that was done for the Companies' CHP Program application, a third party CHP installation would ultimately have a negative impact on non-participating ratepayers.

Q. What happens when the utility installs the CHP system instead?

A. As described in the Companies' CHP Program application, if the Company installs a utility CHP system instead, it retains the demand and energy charge revenues from the sale of electricity (less the reduction, if any, in energy usage and demand due to the use of waste heat to displace electricity, and less the price reduction to reflect the benefits of customer-sited generation); it gains revenues from the sale of waste heat (therms) and from the facilities charge for the absorption chiller (if an absorption chiller is included in the project); and it incurs the capital, operating and maintenance costs for the CHP system installation.

Q. Did the Companies' quantitative economic analysis for its CHP Program application take all of these revenue and cost impacts into account, for both the utility and non-utility CHP scenarios?

A. Yes. The Companies' quantitative economic analysis of the CHP Program for each Company took all of these revenue and cost impacts into consideration. For the non-utility CHP case, the analysis also considered the revenues that a Company continues to receive from a customer for supplemental or backup service provided under its regular rate schedules.

Q. How are the interests of all ratepayers taken into consideration if the utility is allowed to participate?

A. The interests of all customers are taken into consideration primarily by structuring the program of installing utility-owned CHP systems so that non-participating customers are not burdened. In other words, rate impacts over time on non-participating customers should not be greater than those of the alternative course of action (i.e. allowing only non-utility CHP; attempting to address load growth with central station generation but not utility-owned CHP). The Companies' proposed CHP Program is structured so that from a rate impact standpoint, non-participating customers are better off when a host CHP customer chooses to do CHP with the utility rather than a non-utility CHP provider. (See response to HREA-HECO-T-1-IR-8)

If the electric utility is allowed to participate in the CHP market as a regulated entity, the Commission must approve the Companies' Schedule CHP tariff filing, and/or individual CHP Rule 4 project filings, and the Commission, with input from the Consumer Advocate, has the authority to regulate the Companies to ensure that the interests of all customers are taken into consideration. This is in contrast to non-utility CHP installations, where only the interests of the host CHP customer and the CHP developer are considered and there is no regulatory oversight.

<u>DISTINCTION BETWEEN UTILITY AND NON-UTILITY CHP: O&M</u>

Q. On page 19 of HECO T-1, you testified that from the standpoint of benefiting the overall utility electrical system, the ability of the utility to directly control the operations and maintenance of a CHP system will improve its reliability and subsequent impacts on system reliability and power quality. Why would non-utility CHP not be as reliable as utility-owned CHP?

A. Some CHP systems that are installed by third parties may be of substandard design or construction. Some may be operated and maintained by third parties who lack adequate operating and maintenance training or experience. Some CHP systems that are owned, operated and maintained by customers themselves may not be properly or adequately maintained because power generation may not be within the customer's core expertise. This is in contrast to CHP systems that are installed, operated and maintained by the utilities, whose core business is power generation and who have substantial power generation experience. (See response to HREA-HECO-T-3-IR-1)

Q. Could the same system reliability and power quality benefits be realized from non-utility CHP if the utility somehow was given direct control over the operations and maintenance of the CHP system?

A. If the system is designed and installed in a manner consistent with utility standards, then in general, the same impacts and benefits could be derived if the utility is directly in control of the operations and maintenance of the system. If the system is not consistent with utility standards, for example, sub-standard components are used causing more frequent breakdowns, there may still be adverse impacts on system reliability and power quality even if the utility is given control over operations and maintenance. (See response to CA-IR-13)

Q. How might the O&M of a CHP facility not under the direct control of the utility differ from a CHP facility which is under the direct control of the utility?

A. Examples were given in the response to CA-IR-13. A third-party CHP system would be operated to maximize benefits to the customer and the CHP system owner. The utility-owned CHP system would be operated and maintained to balance the customer benefits with the overall utility operation with specific examples below:

Having real-time dispatchability of the CHP units as described below differentiates the utility-owned and operated CHP systems:

- Voltage support: the utility CHP system would standardize the use of synchronous generators. This would allow limited customer and regional voltage support benefits.
- Control logic dispatch: the Companies are still finalizing their preferred CHP unit dispatch parameters, but is considering control system modifications to allow (4) control modes for utility CHP systems which are not currently used on any of the third party installed CHP systems in Hawaii:
  - Normal: the CHP power output would be balanced with the customer's thermal load to minimize the dumping of excess waste heat.
  - Peaking: on command, the CHP unit would maximize its power output without backfeed to the grid. This would provide system generation capacity support and/or support regional distribution system load in the event of a secondary feeder outage or temporary high loads.
  - Minimum: on command, the CHP unit would minimize its power output.

This mode is targeted to the neighbor island systems where on-line regulating units may already be at minimum load and backing off the CHP units would allow greater operating margin on the regulating units.

- Shutdown: utility system operators would be able to remotely shut-down each CHP system due to local network problems and lineman safety.

The maintenance of utility-owned and operated CHP systems would allow the scheduling of maintenance outages to minimize conflicts with distribution system maintenance work and other utility system considerations where regional distributed generation would support the local power quality and reliability.

Q. If direct control over a non-utility CHP system were given to the utility, would there be any potential conflicts of interest?

A. If a non-utility CHP system is under the direct control of the utility, the customer or third party might question how the utility is dispatching or maintaining the CHP system. For example, the utility may decide, based on experience with similar units at other sites, that it needs to bring a customer-owned CHP system down for emergency maintenance. The customer may or may not agree with this determination, as the customer may be more concerned that the CHP system is not operating and is therefore not providing the CHP energy efficiencies to its facility. As another example, the customer or third party may decide to select a brand of CHP system equipment based primarily on near-term capital costs, whereas the utility would be more concerned about life-cycle costs including O&M and would have preferred to operate and maintain another brand of CHP equipment which is standardized with the utility's broader equipment inventory. (See response to CA-IR-13)

Q. This suggests a potential divergence of interests between a non-utility CHP owner and the utility.

A. Yes. Although a non-utility owner and operator of a CHP system has an interest in properly running its CHP unit, its primary interest is its own and is not from the perspective of the overall utility system. The utility is accountable not only to the host CHP customer, but also to the non-participating ratepayers and regulatory agencies.

DISTINCTION BETWEEN UTILITY AND NON-UTILITY CHP: EFFECT ON CHP MARKET SIZE

Q. In HECO T-1, beginning on page 21, you described HECO's assessment of the potential CHP market size in Hawaii. Please summarize HECO's position regarding the impact that utility participation will have on the CHP market.

A. Direct utility participation in the market, meaning utility-owned CHP, would result in more CHP being developed overall.

Q. What is the basis for the Companies' assessment that the overall CHP market will be larger if the utility participates?

A. The primary basis is the broad-based customer support and demand for the Companies' CHP Program, as described on pages 19-22 of the Companies CHP Program application in Docket No. 03-0366. The most critical factor is the sentiment from many facility owners that they do not want to own, operate or maintain CHP systems, and therefore the utility's unique model of offering utility-owned, operated and maintained CHP is appealing. Additionally, there is an appreciation by customers of the utilities' long-standing presence in Hawaii, and also its accountability as a regulated entity. For these reasons, more customers will decide to proceed with CHP if the utility is allowed to offer CHP systems, ultimately increasing the size of the market.

Q. Is this recognition of the utilities' stability and accountability good for the overall implementation of CHP in Hawaii?

A. Yes, absolutely. Buyers of any product or service are better off if there are well-established, recognized, and stable players. The Hawaii Renewable Energy Alliance ("HREA"), according to its direct testimony on page 9, believes for some reason that this is undesirable for the CHP market. From the standpoint of the CHP customer, however, it is a good thing.

Q. Would this increased market also be achieved if the Companies simply serve a facilitating role, without actually offering CHP themselves, as has been proposed by HREA?

A. No. Although the Companies' generic support and facilitation of CHP would certainly help the market, our discussions with customers indicate they place high value on the utilities' direct ownership and accountability for the CHP systems. In other words, direct utility participation would result in an even larger market than if the utility merely facilitated use of the CHP technology.

DISTINCTION BETWEEN UTILITY AND NON-UTILITY CHP: SUMMARY

Q. Could non-utility CHP/DG provide all of the same benefits as utility-owned CHP/DG?

A. No. Third party or customer owned CHP and DG could provide some of the same generic benefits as utility-owned units only to the extent that they meet utility standards for design, operability (including dispatchability), and reliability. These generic benefits may include deferral of new central station generating capacity, displacement of utility central station generation fuel and variable O&M costs, deferral of new T&D capacity, and improved T&D system reliability and power quality. However, only utility owned CHP or DG provides the benefit to ratepayers of retaining customer load and avoiding uneconomic bypass. Additionally, the overall CHP market will be larger only if the utility is able to offer its utility-owned and operated CHP services to customers. (See HECO T-3, page 7-10, and HECO T-4, pages 15-16. Please also refer to HECO's response to CA-IR-10, subpart a., CA-IR-13, subparts a. and b., CA-IR-18 subpart a, and CA-IR-25, subpart a.)

Q. So is utility-owned CHP preferable over CHP systems owned by a customer of a third party, from the standpoint of the utility and its ratepayers?

A. Yes. As stated in HECO's response to CA-IR-10, from the standpoint of the utility and its ratepayers, utility-owned CHP is generally preferable compared to customer-owned or third party-owned CHP. Utility ownership of CHP provides for a bigger CHP market and greater system benefits in terms of improving system efficiency and reliability, deferring or avoiding T&D and generating capacity, and deferring or avoiding fuel and variable O&M costs. Utility ownership of CHP also is preferable from a rate impact standpoint. From the standpoint of the CHP host customer, there are a number of potential benefits provided by the utility-owned CHP option, including the customer not needing to handle O&M of the CHP and the fact that the project would be done by a regulated entity. The qualitative and quantitative benefits that are provided by utility-owned CHP to the utility, its ratepayers, and host CHP customers were discussed in HECO T-1, pages 15-21, and HECO T-3, pages 7-12.

In summary, from the utility and ratepayer standpoint, utility-owned CHP is preferable. From the CHP host's standpoint, there are a number of factors which can make the utility option preferable to self-generation or contracting with a third party, but ultimately, a CHP host will choose its CHP provider on the basis of specific economic, reliability, and compatibility factors as were described in response to CA-IR-5. (See response to CA-IR-10)

Q. Would there be any circumstances where utility-owned CHP is not preferable, from the standpoint of the utility and its ratepayers?

A. Yes. There could be site-specific factors for a project which make it unfeasible. For example, infrastructure improvement costs might be so high for a project that they would outweigh the benefits of retaining customer revenues or providing capacity. In such a case, it could be argued that the utility and its ratepayers are better off if a third party does the CHP project, or possibly, if the customer does not do the project at all.

UTILITY OWNERSHIP OF CUSTOMER-SITED DG: IMPACT ON COMPETITION

Q. Do any of the parties in this docket feel that the utility should not own customer-sited DG?

A. Yes. HREA and COM are opposed to regulated utility ownership of customer-sited DG.

Q. What is the reason for their position?

A. HREA, as stated on page 3 of HREA T-1, alleges that with respect to the DG market, "Hawaii cannot have a competitive market with a level playing field, if the utility is a direct participant." COM similarly claims that utility ownership of customer-sited DG will not support fair market competition.

Q. On pages 9 and 10 of their direct testimony, HREA claims that non-utility CHP developers may be significantly disadvantaged compared to the utility. Exactly who are the non-utility developers, and is it a David and Goliath situation where the non-utility CHP developer is at the mercy of the utility?

A. Non-utility CHP developers in Hawaii have typically been equipment manufacturers (e.g., Pacific Machinery, Cummins, Hess), energy services companies (e.g., Johnson Controls, Honeywell, Noresco), and to a lesser extent, electrical-mechanical design firms. With the exception of a few small local firms, the non-utility CHP developers tend to be linked to large national or international corporations, with hundreds of millions of dollars in annual revenues. Host CHP customers have also been directly involved in owning and operating CHP systems, and host CHP customers tend to be hotels, hospitals, and government agencies. Clearly, CHP market players range in size, with some smaller and some larger than HECO.

Q. The utility, in its own CHP market forecast, anticipated a majority of CHP systems being owned by the utility. Can a competitive market for DG exist in Hawaii if the regulated utility is allowed to own, operate, and maintain a large number, perhaps even a majority, of customer-sited CHP installations?

A. As described in HECO's response to HREA-HECO-T-6-IR-5, a competitive market will exist even if the utility owns and operates a majority of the CHP installations. HECO's estimate of its potential market share was based on its understanding that customers will be receptive to the local utility ownership option, not because other service providers will be excluded from the market, or excluded from offering a third-party ownership option. A market is not made more "competitive" by excluding the preferred option from the market.

The utility will be purchasing CHP equipment from the manufacturers and doing so in a competitive fashion, via the Companies' new CHP equipment procurement process that was discussed on pages 32 and 33 of HECO T-1.

The utility also is not offering balance of central plant equipment and services, which is the focus of most energy services companies and which in many cases goes hand-in-hand with a CHP project. The balance of central plant equipment and services in most cases dwarfs the CHP component of a customer's facility. For example, the CHP portion of a central plant may represent only 20% of the entire central plant value. Thus, the Companies' CHP projects will be complementary to the central plant services and equipment of the energy services companies.

In addition, a fair amount of CHP projects will be independently developed by customers, manufacturers, or energy services companies. In short, all parties will have fair opportunities to offer equipment and services to customers.

Finally, as described earlier, the overall market size for DG/CHP will be larger if the utility is allowed to directly offer CHP to customers, which would benefit all parties including the manufacturers and energy services companies.

Q. The above describes from a factual and practical standpoint how the different stakeholders – developers, equipment vendors, customers, and the utility – will all coexist competitively in the Hawaii CHP market. What is HREA's opinion regarding this?

A. HREA, in HREA-HECO-T-6-SIR-1, appears to dismiss this practical description of how the stakeholders will function together in the Hawaii CHP market, and instead is focused on a belief that perfect competition, as defined theoretically, is required for a competitive market. The theoretical assumptions of perfect competition offered by HREA are that (1) each firm should produce only a small percentage of total market output, (2) no individual buyer should have any control over market price, (3) buyers and sellers must regard the market price as beyond their control, (4) there is perfect freedom of entry and exit from the industry, (5) firms in the market produce homogeneous products that are perfect substitutes for each other, (6) there is perfect knowledge, i.e. consumers have perfect information about prices and products, and (7) there are no externalities which lie outside the market.

Q. What is the Companies' response?

A. As noted in their response to HREA-HECO-T-6-SIR-1, the Companies have not stated that perfect competition will exist in the CHP market if the Companies are allowed to participate on a regulated basis. There are very few, if any, markets where perfect competition actually exists.

As for the main assumptions noted in HREA's definition of perfect competition:

- If the Companies offer CHP on a regulated basis, the Companies cannot control the price by controlling the supply - they must offer the service to parties meeting the eligibility criteria at the regulated price structure described in the CHP Program application, Section VI, Schedule CHP.
- The Companies would not be able to control the market price. Schedule CHP is designed, in part, to respond to market price signals.
- Entry to the market is not blocked by the Companies participation in the market on a regulated basis.
- Any party may offer the same technical package as the Companies and mirror the Companies' pricing methods in Schedule CHP. The Companies' CHP projects will be filed with PUC for review.

- The Companies' participation in the CHP market on a regulated basis should positively impact customer knowledge about CHP system prices and products, since it will give customers another source of information regarding the available options.

Q. What is the current status of the new CHP equipment procurement process?

A. A Request for Qualifications ("RFQ") was issued to nine manufacturers of CHP equipment on September 10, 2004. The RFQ requested comprehensive information on products, servicing capabilities, project experience, and other criteria. Responses were required to be postmarked by October 1, 2004 and responses were received from seven of the manufacturers. At this time, HECO is reviewing the submittals and is selecting a short list of vendors. These vendors will be reviewed further, and ultimately, several will be selected as pre-qualified vendors.

Q. What do you anticipate as far as the number of pre-qualified vendors?

A. I cannot say definitively at this time how many pre-qualified vendors we will select, however I anticipate we will end up with at least three. The number will depend on how broad the vendors' equipment lines are and whether the vendors can suitably supply equipment and services to the variety of CHP projects the Companies may develop.

Q. How will the pre-qualified vendor process work?

A. The formal details are still being developed as we draft our pre-qualified vendor agreement. In general, we will use the CHP systems from the pre-qualified vendors for our projects, using the equipment that we judge will best fit the needs of the particular project. In some cases, it may not be clear that the equipment of one pre-qualified vendor is the obvious choice for a project, and we may seek bids from more than one pre-qualified vendor. This would also be the case for large projects.

For example, very large CHP systems may warrant use of equipment bidding due to the cost of equipment. Medium size projects might be bid or assigned to a more limited group of pre-qualified vendors offering either packaged or engineered systems. Small CHP systems might be procured directly from a single qualified vendor of packaged systems.

Q. Why wouldn't you bid every CHP project?

A. As I described on page 32 of HECO T-1, the objectives of the new procurement process are, among others, (1) to ensure provision of quality CHP products and services, (2) to standardize equipment and designs, (3) to achieve efficiency in the equipment selection process, and (4) to obtain cost savings for the utility and its ratepayers, especially over the life cycle of the CHP installation. Bidding every small CHP project would generally not be efficient.

Q. What is the current status of the Hess teaming agreement?

A. The teaming agreement between HECO and Hess was officially terminated by letter agreement on October 7, 2004. See HECO R-100.

Q. Will "pre-qualified vendor" status prevent an equipment manufacturer from providing equipment to a non-utility CHP project?

A. No. The objectives of the Companies' pre-qualified vendor process are to secure procurement efficiency, equipment standardization, cost savings, and quality products and services. It will not lock up a vendor from supplying equipment to non-utility projects.

Q. In HECO T-1, you addressed various potential impacts on competition that the proposed utility CHP Program might have. Please reiterate these issues.

A. In HECO T-1, I stated on page 26 that the Companies' proposed CHP Program would provide substantial benefits to all utility customers and the State of Hawaii, without restricting the right or ability of non-utility CHP vendors and developers to offer their products and services to such customers. I described the distinct differences between the Companies' CHP program offerings and those of non-utility vendors, and testified that customers should be allowed to choose between such offerings. In all cases, non-utility vendors are free to offer whatever services they can provide to customers. The utility will sell energy to its customers on the basis of regulated rates, and non-utility vendors will be free to compete against the utility rate structure.

On pages 28 to 30 of HECO T-1, I discussed three specific issues posed by the utilities' participation in CHP, (1) access to information, (2) interconnection review, and (3) standby charges.

Q. Please describe the issue regarding access to information.

A. As described on page 28 of HECO T-1, the utility does not have any advantage over access to customer information. To begin with, it is fairly obvious to any energy services company or CHP developer that the most likely candidates for CHP are facilities with continuous thermal loads such as hospitals and hotels. Once a potential CHP host is identified, information regarding the host's electrical usage can be obtained directly from the host or from the utility if the host authorizes the release of the data.

However, the most critical data required for a CHP proposal – thermal energy use information on the customer's side of the meter – comes from the customer itself. What is required to design a CHP system is detailed data concerning how electrical and heat energy is used on the customer's side of the meter, especially in central plant and other key equipment. In this respect, every customer has more information available than the utility and is free to make its own decision whether or not to share that information with any potential CHP developer, including the utility. The electric utility generally has no such information unless, like any energy services company, it has previously worked with a customer via an energy audit.

As evidence of this fact, Hess was very successful in the Hawaii CHP market in identifying potential CHP customers and working with them to obtain facility data required for a CHP design. Another example of data accessibility is the work performed by energy services companies who obtain detailed facility energy usage data in the normal course of their business.

Q. What are the concerns regarding interconnection standards?

A. Parties are alleging that the Companies will be able to use the interconnection requirements and review process to unfairly delay non-utility CHP projects or add cost to the projects. These allegations are without basis. The Company has a standardized interconnection tariff, standards, and review process, in the form of Tariff Rule 14.H, which has been reviewed and approved (as revised) by the PUC. All Company CHP installations will meet the same technical standards, and are subject to the same review and study process, as non-utility CHP installations.

Although the interconnection process is fundamentally sound, we acknowledge that more guidance could be given to help outside parties understand the interconnection review process and requirements.

Q. What about standby charges, specifically the allegations that HELCO's Rider A, Standby Service, would give HELCO's CHP an unfair advantage?

A. The Companies in response to Informal Complaint No. IC-03-098, pointed out that such concerns were overstated, as the Rider A provision was stipulated to by the Consumer Advocate and approved by the Commission after extensive review in Docket No. 99-0207. If DG/CHP customers install the DG/CHP meter required by the rider and take advantage of the options offered by the rider such as the Scheduled Maintenance Option, they may well be able to obtain backup service at lower cost than under HELCO's regular rate schedules. (See response to Hess-DT-IR-2 subpart b)

On page 29 of HECO T-1, I referred to Ms. Seese's testimony, in HECO T-5, which explained why a standby service provision was proposed on the Big Island – due to HELCO's concern that application of its existing rate schedules to customers with on-site generation would not cover the cost of providing backup service to such customers. The goal in designing Rider A was to set fair and equitable rates that reasonably recovered the costs of providing standby service from standby customers imposing such costs.

As summarized by Ms. Seese, HELCO's position is that Rider A should continue to apply to non-utility DG/CHP installations unless it is determined that that would be unfair after HELCO enters the CHP business on a regulated basis. Thus, in the Companies' CHP Program application, HELCO has requested either (1) a finding that continued application of the standby service rider is fair in light of its proposed CHP pricing, or alternatively (2) a determination that application of the standby service rider to non-utility DG/CHP should be made voluntary.

Q. Please explain the distinctions between the Rider A charges and the regular rate schedule for a DG/CHP customer.

A. The distinctions between the Rider A charges and the regular rate schedule for a DG/CHP customer are the following:

1. A DG/CHP customer served by HELCO is billed under the applicable rate schedule in conjunction with Rider A. The total monthly bill of a DG/CHP customer under the applicable rate schedule includes the Rider A's standby charge applied to the customer's standby kW load.
2. A DG/CHP customer's billing kW under the applicable rate schedule is reduced by its standby billing kW. This ensures that a DG/CHP customer is not charged twice for the same kW.

(See response to HESS-DT-IR-2 subpart a)

Q. Certain parties have questioned whether any CHP system, regardless of ownership by the utility or a non-utility entity, should be assessed the same rates and charges for standby service. Would this serve any purpose?

A. Such an approach would not serve any real purpose. The Company would have to charge different rates than those based on its rate schedules for CHP system electricity (i.e., for CHP service), charge for "supplemental" service (i.e., electricity from the grid) based on its rate schedules, and for backup service based on Rider A. If the Company's CHP system performed well, it would receive more revenues for CHP service and less for back-up service. If the CHP system performed poorly, the Company would receive fewer revenues for CHP service and more for back-up service. The customer would be indifferent (as long as the CHP system thermal output was sufficient for its needs) since the utility would provide both services. Rider A makes sense where the providers of CHP service, and backup and supplemental service, are different entities. (See response to CA-IR-15 subpart b)

Q. Does HREA allege any other competitive issues?

A. Yes. Besides the issues of buyer familiarity with sellers, access to information, and application of interconnection standards, HREA makes a number of other allegations. HREA claims on pages 9 and 10 of its direct testimony that transaction costs, permitting costs, and the time and expense required to negotiate a sales or use agreement pose unfair barriers to non-utility CHP developers.

These allegations are false as the utility is also subject to numerous transactions, permitting, and negotiating costs in the course of doing business and providing services to customers.

HREA also alleges that the utility has unfair access to lower cost financing. This allegation is overly broad and does not consider advantages that non-regulated entities may enjoy. As an example, the utility's cost of capital may actually be higher than an unregulated entity's since non-regulated companies will typically use a higher debt/equity ratio than is appropriate for a regulated utility. Since debt is a lower source of funds than equity, the higher debt/equity ratio results in lower overall cost of capital. Non-utility entities may also have greater flexibility to determine financing on a project-specific basis, whereas HECO must plan its capital structure for the company taken as a whole. Since HECO has an obligation to provide electric service, it must maintain its capital structure targets and credit quality in order to ensure access to capital markets for all its projects, not just provide financing for the CHP projects.

HREA claims that the Companies have the advantage of being able to rate-base their costs and therefore have lower risk than other DG providers. Yet rate basing of costs is dependent on Commission review and approval. Furthermore, return on assets in rate base is subject to limitations. We also note that the assets and financial risk tolerance of the Hawaii utilities may be dwarfed by those of large national or international DG providers (e.g. Johnson Controls).

Finally, HREA claims that third party CHP developers must share competitive information about pending CHP projects with the utility as part of the interconnection agreement process. All such information is required by Rule 14.H, as approved by the Commission.

Q. How would you summarize the alleged barriers to retail competition in the Hawaii DG market?

A. Non-utility DG developers are not competitively disadvantaged when compared to the regulated utility's own development of DG, especially with regard to large national firms that are established in Hawaii. In almost all areas, the utility is subject to the same, if not greater, challenges as non-utility developers.

Q. Given this, why would the utility seek to develop and own customer-sited DG?

A. The Companies' direct participation in the CHP market will serve as another competitive option for customers to consider. The utility option goes even beyond that, though, in terms of its benefits to the electric system and to all ratepayers that were listed earlier and in HECO T-1.

Q. Would preventing the Companies from participating in the CHP market as a regulated entity enhance competition?

A. No. This would do the opposite. You would eliminate a CHP alternative that is attractive to the host customer and also provides benefits to other non-participating customers. Ultimately the customer has fewer choices.

Q. So does the utility enjoy any unfair advantage in developing CHP projects over a non-utility developer?

A. Not at all. In fact there are circumstances that make it more challenging at times for the utility to develop CHP than a non-utility entity. Non-utility CHP systems may offer quicker installation schedules compared to utility systems, to the degree that the utility needs to obtain PUC approval for projects done under Rule 4. The non-utility provider may also have more flexibility in providing additional services and equipment that would otherwise be considered below the line from the utility's standpoint. Unregulated competitors also can offer their products and services without open review of their prices or terms and conditions of service, as must be done by the utility before the Commission. (See response to CA-IR-14 subpart b)

UTILITY OWNERSHIP OF CUSTOMER-SITED DG: AUTHORITY

Q. The County of Maui asserts "that MECO cannot own and operate Consumers' DG/DER because MECO is not authorized to do so under its franchise and statutory authorizations." (COM-T-1, page 8.) What is the Companies' response?

A. Insofar as the County is attempting to raise a legal issue, it can be addressed in the post hearing briefs. I would note, however, that the County has not cited any language in MECO's franchise in support of its assertion. In general, the Companies' franchises grant them the right to use public rights of ways, and impose franchise fees and certain service obligations in exchange for the grant. The franchises do not purport to limit the franchised utilities to owning and operating central station generating units, or prohibit them from owning and operating customer-sited generating units (or prohibit them from engaging in other activities, including non-utility activities).

Q. What about the County's assertion that "the ownership and operation pf consumer DG and DER for private use does not appear to be a public utility activity …" (COM-T-1, page 8.)

A. The ownership of DG, and the retail sale of electricity to electric utility customers from such DG, whether by the electric utilities or third-parties (as opposed to customer ownership of customer-sited DG solely for the customer's own use), is clearly a matter of public interest.

Prior to the commencement of this docket; the Companies had not formulated a position as to whether a CHP System or a distributed generator owned by a third-party should be regulated by the Commission, except in the case of nonfossil-fuel generating facilities [See the Companies' response to CA-SOP-IR-14, which refers to their Motion to Intervene filed August 6, 2002 in Docket No. 02-0182 (Petition of PowerLight Corporation)].

In the case of CHP systems, the Companies propose to offer such systems on a regulated basis where utility ownership of such systems is cost effective and does not burden non-participating customers. This would provide customers of CHP systems with a regulated alternative. This would also provide a mechanism for non-participating customers of the regulated utility to be considered as the number of such installations increases significantly. Under these circumstances, the Companies do not anticipate that it will be necessary for the Commission to regulate CHP systems that are owned by third-party providers and sell the output of their systems only to the on-site customer.

Q. In some instances (such as the sale of propane) by The Gas Company ("TGC"), services or products can be offered as either a regulated or unregulated basis. Would the Companies offer CHP systems on an unregulated basis, if that is the only option?

A. The Companies' position in this question was presented in HECO T-1 (pages 20-21). At this time, the Companies do not anticipate participating in the DG market if only a separately capitalized, separately staffed affiliate was allowed to participate. The Companies' reasons for providing CHP system services as a regulated utility service are stated above and in the CHP Program application. The expertise and resources to provide such services reside in the utility. The customers desiring such services are utility customers. The objectives of the program are utility objectives. The needs of participating and non-participating customers can be served if the program is provided on a regulated basis, while the impact on non-participating customers would be a non-factor for an unregulated supplier of CHP systems. Utilities are in a better position to provide customers with the option of having the services provider be the entity that owns, operates and maintains CHP systems, which should increase the market for such systems.

The Companies might consider providing CHP systems services on an unregulated basis, if that was the only option, through the utilities themselves, in the manner that TGC provides both unregulated propane services and regulated

SNG and propane services within the same entity (and competes with unregulated propane vendors in both "markets".) However, this would present opportunities for conflicting objectives between the regulated and unregulated businesses of the Companies, which would not be present if the Companies provided CHP systems services on a regulated basis. (See Response to TGC/HECO-SOP-IR-3).

<u>CUSTOMER PREFERENCE AND SUPPORT FOR UTILITY-OWNED DG CANNOT BE IGNORED</u>

Q. How important is customer preference when considering technology and ownership options for customer-sited DG?

A. It is very important and cannot be ignored. I stated on page 8 in HECO T-1 that customers making up this market would determine whether a form of DG is "feasible and viable for Hawaii".

Q. Please expand on why it is that customers will play a critical role in determining whether DG is feasible and viable.

A. In HECO T-1, beginning on page 7, I described the criteria for a form of DG to be "feasible and viable for Hawaii". The criteria are that the DG must be (1) technically feasible, (2) commercially available, (3) economically viable (i.e., cost-effective versus other options), (4) price competitive in the short-term, (5) sustainable in the long-term (i.e., backed up by adequate infrastructure support with respect to O&M and fuel), (6) able to address site-specific constraints (e.g., with respect to permitting) and (7) able to meet the needs of customers.

The seventh criterion, the ability of the DG to meet the needs of the customer, is an absolute requirement for customer-sited DG. For customer-sited DG applications, the decisions to install customer-sited generation, the type of technology, and the ownership option, will be made by the customers allowing the installation of such generation.

Q. What are the key factors that customers consider when making these decisions?

A. All of the factors listed on HECO T-1, pages 7-8, are important, although individual customers may weigh factors differently. Customers generally will not consider technologies that are not technically feasible or commercially available or that are not able to address site-specific constraints (although this factor will vary among customers because it is site-specific). Some customers will be more concerned with life-cycle costs, while others will focus on upfront costs. (HECO T-1, page 8, lines 8-18.) Reliability is a more important customer need for some customers than for others, because of the differences in their business operations. A few customers may give more weight to externalities. (Response to CA-SOP-IR-2.) These are not the only factors that customers will take into account in deciding to install customer-sited generation. They will consider whether they are expanding or renovating their operations (HECO T-6, page 5.) They will consider the vendors and types of vendor offerings available to them. (HECO T-1, pages 24-26.)

Commercial and industrial customers will focus primarily on controlling energy costs and improving operational efficiency, and therefore customer-sited generation and its ownership arrangements will have to provide sufficient economic and operational value to the customer. Certain customers also require special electric service reliability, such as hospitals, and they may choose to install appropriately equipped generation to meet those needs. Finally, all customers will require that customer-sited generation be compatible with their facility and existing operations. For example, a resort hotel will consider noise and aesthetics in its decision to install a generating unit.

Q. How is this relevant to the Companies' proposed CHP Program?

A. The fact is that numerous customers see value in the Companies' proposed CHP Program, validating the Companies' position that the utility CHP model is differentiated enough from offerings of non-utility vendors, such that the proposed utility CHP Program truly represents another distinct option for customers. Customers should be given as many options as possible in order to increase competition and to stimulate growth in the DG market. Based on communications with customers, many customers will pursue the installation of CHP under the proposed utility model that otherwise would not have. Thus, direct utility participation in CHP will effectively increase the size of the CHP market in Hawaii.

Q. You mention customers seeing value in the Companies' proposed CHP Program, and one of the topics discussed in HECO T-1 was customer support for HECO's involvement in CHP. Have there been any additional showings of customer support since HECO T-1 was filed?

A. Yes. The most significant evidence of customer support and desire for HECO's proposed CHP Program is the recent execution of two contractual agreements for utility owned CHP systems at customer sites.

Q. Please describe these CHP contracts.

A. The first CHP agreement was executed on September 8, 2004 between HECO and Pacific Allied Products, a major plastics and Styrofoam manufacturer located in Campbell Industrial Park. The contract is for HECO to install, own, operate, and maintain a CHP system on the Pacific Allied site consisting of two 250 kW diesel generators and a 100 ton absorption chiller.

The other CHP agreement was executed October 6, 2004, between HELCO and the owners of the Sheraton Keauhou Resort, a newly renovated hotel in Keauhou on the Big Island. The contract is for HELCO to install, own, operate, and maintain a CHP system on the hotel site consisting of two 370 kW diesel generators and a 95 ton absorption chiller.

Q. How long are these contracts for?

A. Both the Pacific Allied and Sheraton Keauhou contracts are twenty-year agreements.

Q. Why did the Companies choose a twenty-year contract term?

A. The utility's focus is on working with customers who, like the utility, are concerned about long-term stability and place value on longer-term contracts, which help to defer the need for central station generation, which has 30-50 year lives. There will certainly be customers who prefer not to sign long-term contracts, and the utility's proposed program will not be a fit for them. In such cases, the utility is at a disadvantage compared to non-utility CHP providers who are willing to offer shorter term agreements. The point though, is that the utility is pursuing CHP for utility purposes, and shorter term agreements would not provide the same system benefits.

Q. How will the utility integrate new technology if the contract terms are for so long?

A. A key provision of the CHP Agreement proposed in the Companies' CHP Program is that the utility will be responsible for operation, maintenance, and replacement of the CHP equipment throughout the term of the CHP Agreement. To the extent that new technology can be integrated in a cost-effective manner without degrading CHP system performance, the utility will be able to capitalize on technology advances.

Q. What is the current status of the Pacific Allied and Sheraton Keauhou projects?

A. Now that CHP agreements have been executed, HECO and HELCO are preparing to submit the contracts to the Commission for their review and approval pursuant to Rule 4 of the Companies' tariffs. Hopefully we will obtain the Commission's approval so that we can move forward and install CHP while the facilities are still completing their respective renovations.

Q. Did these facilities consider other CHP proposals, and if so, why did these facilities decide to pursue CHP with the utility?

A. Both facilities did consider non-utility CHP proposals. In signing the CHP agreements, it is apparent that both customers found it preferable for the regulated utility to be handling the complete installation, operation, and maintenance of the CHP systems, while the CHP host is being provided with a satisfactory amount of energy savings.

Q. Have there been any other showings of customer support or interest in the Companies' proposed CHP Program?

A. Yes. We continue to be asked on occasion to brief customers on our proposed program. My staff and I are responsive to these requests, but I personally take care to ensure that we brief the customers on the current status of the DG regulatory proceedings, the suspension of our proposed CHP Program application, and the Rule 4 approval process. Even with this information, many customers still ask us to look at their facilities to see if CHP makes sense.

DG IS NOT SIMILAR TO DSM MEASURES/PROGRAMS

Q. How does the COM characterize DG with respect to demand-side management ("DSM") measures and/or DSM programs?

A. The COM characterizes DG and other consumer energy products and services as distributed energy resources ("DER"), and "In a broad context, DER can also be referred to as demand-side management ("DSM") resources." (COM-T-1, page 4, lines 11-17.) The COM asserts that "DSM programs should be established for DG products and services." (COM-T-1, page 14, line 15.)

Q. Is it reasonable to characterize DG as a DSM measure to be included in a DSM program?

A. No, it is not. DSM Programs are designed to influence the <u>use</u> of energy. DG is a resource that <u>supplies</u> energy. The distinction between the use and supply of energy was made by the Commission in its Framework for Integrated Resource Planning ("IRP") (Decision and Order No. 11630, Docket No. 6617). The IRP Framework defines DSM Programs as:

"... programs designed to influence utility customer *uses* (emphasis added) of energy to produce desired changes in demand. It includes conservation, load management and efficiency resource programs." (See IRP Framework, Section I, page 1.)

HECO maintains that the inclusion of the word "uses" implies that the IRP Framework intended to apply the term "DSM" only to those measures that affect how customers use energy, not how it is generated.

The IRP Framework definition of Supply-side programs is:

"... programs designed to supply power. It includes renewable energy." (See IRP Framework, Section I, page 3.)

Under this definition DG is clearly a supply-side resource, and not a DSM measure.

Q. Can you elaborate further on the differences that exist between DSM measures and DG resources in terms of ownership, operation and maintenance?

A. Yes. The measures installed pursuant to energy-efficiency DSM programs generally are replacements for equipment, fixtures, or processes that are used in the customer's business or home, such as energy efficient lighting, or motors, or water heaters. Thus, DSM measures generally can be "operated" and "maintained" (to the extent that is necessary) using the O&M expertise or resources that the customer already has. These DSM measures, which allow electricity to be used efficiently, or substantially reduce the use of electricity (such as is the case with solar water heaters, where electricity is the back up water heating source), are distinctly different from DG resources, which generate electricity. The option of utility ownership of a DG resource, such as a CHP system, is desirable to customers precisely because they often do not want to own, operate and maintain generating resources.

Q. Would it be reasonable to treat the Companies' proposed CHP Program, Docket No. 03-0366, like a DSM program and offer incentives to customers to install CHP systems?

A. No, it would not be reasonable to treat the Companies' proposed CHP Program like a DSM program, for example, the Residential Efficient Water Heating ("REWH") Program, which provides incentives to customers who install solar systems, because there are marked differences between the two types of programs.

Q. Please explain some major differences between the CHP Program and the REWH Program.

A. Some major differences between these two types of programs include:

1. CHP systems produce electricity, generally cost in the hundreds of thousands of dollars, are operated, and require extensive periodic maintenance. (See response to TGC/HECO-SOP-IR-24, subpart b.) Solar

systems heat hot water, generally cost only several thousand dollars, and do not require operation or extensive maintenance.

2. There are a limited number of vendors offering CHP systems, and to date there have been only a small number of CHP systems installed in Hawaii, and the Companies expect that their involvement in the CHP market on a regulated basis will result in an expanded market. Under the Companies' REWH Programs, over 20,000 solar systems have been installed statewide, and it is estimated that there are some 80,000 solar systems in operation statewide, indicating there is a broad market with numerous solar vendors.
3. In the design of the Companies' CHP Program, because of the more limited opportunities for customers to participate in the CHP Program (i.e., many commercial and industrial customers do not have a use for the waste heat from the CHP systems that precludes them from participating in the program), the impact to non-participants was explicitly taken into consideration such that participants as well as non-participants benefit from the Companies' involvement in the CHP market on a regulated basis. The impacts to non-participants were accepted in the REWH Program because there are more broad based opportunities for customers to participate in the program, and also because the program furthers the State's goals of renewable energy and a reduction in the use of fossil fuels.
4. If the Companies provided an incentive to customers to install a CHP system, and had no further involvement with the operation and

maintenance of the CHP system, there would be no assurance that the CHP system was being properly maintained in order to provide the expected reduction of the peak on the utility system from the CHP system operation. Solar systems, as stated above, do not require extensive maintenance and have a reasonable track record with providing the expected reduction in electricity usage and corresponding system peak reduction.

5. The Companies' CHP Program entails utility ownership of a limited number of CHP systems in order to achieve the intended results. It would be impractical for the Companies to own thousands of solar systems.

Q. Following up on your third point, HECO T-1, page 19, lines 11-13, stated "The interests of all customers are taken into consideration primarily by structuring the program of installing utility-owned CHP systems so that non-participating customers are not burdened." Are DSM programs designed in a similar manner?

A. Generally, no. DSM programs are not currently designed so as to avoid any "burden" on non-participants. Thus, 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, energy <u>bills</u> should be reduced because of the reduction in energy use.) Whereas <u>all</u> 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.)

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).

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.

Q. Solar water heating and photovoltaic (PV) systems both use solar energy. Are PV systems candidates for inclusion in DSM programs?

A. Generally, no. The distinction between DSM measures and DG is blurred somewhat in the case of small DG resources, such as residential PV systems. But there are still substantial differences between solar water heating and PV systems in terms of function, cost, benefits to and impacts on non-participants, and mechanisms for utility support.

Solar water heaters are passive collectors of solar energy. The collected energy is directly transmitted into hot water without the generation of electricity. In addition to being a renewable energy resource, solar water heaters are an important DSM measure because water heating is generally the largest residential electric load and reducing this load can help to shave the Companies evening peak demand.

PV systems are also a renewable energy resource, however they generate electricity. The output from a PV system is highest during the "solar day", which for the most part finishes before the Companies' priority peak demand period of 5:00 to 9:00 p. m. weekdays. PV systems therefore do not help to shave the Companies evening peak demand.

The cost of solar water heaters is on the order of $4-7000, and there are many sellers of such systems. Residential PV systems cost on the order of $9,000-13,000 per kW (without battery backup) and $11,000-16,000 per kW (with battery backup), and there are a limited number of installers of such systems. (In contrast, a 580 kW CHP system with an absorption chiller would cost on the order of $900,000 to install, and $60,000 per year to operate and maintain.)

HECO supports solar water heating through the incentives ($750 per installation) in its highly successful REWH Program. HECO supports PV systems through its State-mandated net energy metering tariff, as well as through its Sun Power for Schools Program and other demonstration projects. The State of Hawaii provides substantial taxpayer support to both solar water heaters and PV systems through a renewable energy tax credit.

IMPACT FEES ARE NOT APPROPRIATE

Q. Does the County of Maui recommend that the Commission implement connection charges (or impact fees) for new customers and expanded loads?

A. Yes, the County of Maui makes that recommendation in COM T-2, page 97, lines 13-14. The County of Maui claims that "The addition of new customers requires additional generation, transmission, and distribution plant and the associated cost." (COM T-2, page 41, lines 19-20.) Furthermore, since "New customers add more to cost than to revenues for the utility, [they] should pay a connection charge (impact fee) designed to recover this shortfall at the time of connection to the system." (COM T-2, page 56, lines 10-13.)

Q. Should the Companies (or MECO) 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)?

A. In Hawaii, electricity customers generally are not charged differential rates based on their vintage, and members of a customer class are treated equally. For example, rural residential customers are generally charged the same as urban residential customers, even though it may cost more on average to serve rural customers.

The only contributions required under MECO's tariff are those specified by Rule 13, which requires non-refundable contributions to cover the cost difference between an overhead and an underground distribution system when required or requested for a subdivision, and to cover the cost of other "special facilities." In addition, advances, which are subject to refund, are required when the cost of individual line extensions exceed 60 month's estimated revenue, and when overhead lines are extended to subdivisions or developments in advance of service requests by individual customers.

Q. What are the practical difficulties in establishing impact fees?

A. The equity of levying differential charges based on a customer's vintage must also be taken into consideration. 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 generations 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. Numerous complex questions would arise such as:

- Should generating units be "tagged" and identified with specific vintages of customers?
- If new customers were required to pay contributions in aid of construction, would new customers then be relieved of the necessity of paying demand charges?
- Would new customers pay lower energy charges because new generation and transmission facilities are often more efficient? If and when the next combustion turbine on Maui (which is originally used as a peaking unit,

but is more costly than a simple peaker because it is designed to be incorporated into a combined-cycle unit) is incorporated into an energy-efficient combined cycle unit in the future, will the customers (and loads) that were assessed an impact fee be entitled to pay lower energy charges?

- When existing generation is replaced, or modified to accommodate new environmental requirements, or to replace existing components, should impact fees be charged to existing customers, and will new customers (or loads) that were assessed impact fees be excluded from the new assessment?
- For example, when the Hamakua Energy Partners combined cycle unit was added to HELCO's system on the Big Island in 2001 (through a power purchase agreement), there was a <u>base</u> rate increase authorized (in Docket No. 99-0207) that included the impact of the payments for firm capacity under the contract. However, customers also received the benefit of the lower energy costs associated with the facility, which were flowed through to customers through HELCO's ECAC. Thus, a base rate increase was triggered by the addition of the new capacity, but it was not indicative of the net rate impact on customers of adding the new capacity.
- Will existing customers who increase their use of electricity be assessed an impact fee, and will they receive a rebate if they subsequently decrease their use of electricity? (For example, should residential customers be charged impact fees because children are "added" to their families, thereby

increasing their use of electricity, and should existing residential customers be rewarded with a rebate when their children leave home?)

- The size and type of new generators added to a system is based on overall utility system cost impacts and needs. For example, peaking units may be selected to accommodate the addition of as-available renewable energy to the system, and base loaded units may be added (or combustion turbines may be converted into base loaded or cycling units) based on energy cost savings. How would these factors be considered?

As a practical matter, impact fees would be extremely difficult to establish and implement in any equitable manner. The need for new generation is driven by load growth and load growth is not caused just by new customer facilities and large renovations to existing facilities.

Q. Doesn't the addition of substantial new generation tend to put upward pressure on rates?

A. Yes, at least with respect to base rates. 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.)

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. For example, when the Hamakua Energy Partners (HEP) dual-train combined-cycle unit was added to HELCO's system on the Big Island in 2001 (through a power purchase agreement), there was a <u>base</u> rate increase authorized (in Docket No. 99-0207) that included the impact of the payments for firm capacity under the contract. However, customers also received the benefit of the lower energy costs associated with the facility, which were flowed through to customers through HELCO's ECAC. Thus, a base rate increase was triggered by the addition of the new capacity, but it was not indicative of the net rate impact on customers of adding the new capacity.

Q. The County of Maui refers to the estimated cost of MECO's next generating unit, M18, and the estimated cost of the first CT that might be added at Waena. Do you have any comments?

A. Yes. 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. As was indicated in the response to HECO-Companies-SOP-IR-11, 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. (See response to COM-HECO-DT-IR-20.)

Q. What other problems have you identified with the COM's proposal?

A. The COM makes a simplifying assumption that only new customers or existing customers with large renovations are responsible for load growth. However, existing customers, most of whom did not make large renovations, accounted for nearly half of the load growth on the island of Maui in 2003. Therefore, the 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 the COM's proposal.

Q. Has the Commission previously considered the concept of impact fees, and if so, what was its determination?

A. Based on these types of considerations, the Commission primarily rejected a similar impact fee concept prepared by Mr. Lazar for the Big Island in a HELCO rate case. See Docket No. 6999, Decision and Order No. 11893 (October 2, 1992), pages 101-102.

Q. The COM-T-2, pages 88-91, recommends that "...large customers be required to execute multi-year contacts with advance notice requirements to significantly change their demand on the utility." The COM asserts that the situation on Lanai (whereby MECO and Castle & Cooke Resorts executed a rate discount service contract, approved by the Commission in Decision and Order No. 20811, Docket No. 03-0261) could have been anticipated and prevented. What is the Companies' response?

A. Multi-year contracts with large customers may be appropriate for a number of reasons, and the risk of stranded costs is a valid consideration in designing rates where customers have competitive alternatives. As a general proposition, however, the concept of requiring large customers to execute multi-year contacts with substantial advance notice requirements as a pre-condition to significantly changing their demand on the utility could negatively impact economic development in Hawaii, could have the perverse impact of inhibiting the implementation of energy efficient CHP systems and energy efficient DSM measures that have the potential to significantly reduce customer usage of electricity supplied from the gird, and could negatively impact a customer's ability to make modifications to its own operations. For example, such a "contract" could be an obstacle to a customer expanding its own facilities and could negatively impact a hotel which has to temporarily close a wing during a tourism slump. And, in the Lanai situation, the County's comment inappropriately criticizes MECO for not imposing a requirement that it did not have the right to impose under its tariff or Commission rules.

Q. Is it the term of the "contract" that would be a problem?

A. No. What the County has not indicated is that such a contract would be ineffective unless a substantial fee was assessed if the customer changed its load level or left the system without giving the required notice. Thus, it appears that the County is proposing a form of termination or "exit" fee when a customer reduces its load or leaves the system, and a form of "impact" fee when the customer increases its load. While there are circumstances under which such an early termination fee can be justified (such as when a customer contracts for a special rate arrangement, or receives a special benefit to be "amortized" over some period of time), the ramifications of such a fee should be fully identified and explored before the fee is imposed on an across-the-board basis. (See response to CA-SOP-IR-23. Impact fees were addressed in the preceding section.

Q. In the Lanai situation referred to above, was the rate discount service contract appropriate?

A. Yes. The justification for the Lanai discount was fully documented in Docket No. 03-0261. The Consumer Advocate in its Statement of Position indicated, based on its review, that the discount is reasonable. The Commission found in Decision and Order No. 20811 that the discount to Castle & Cooke Resorts is reasonable and in the public interest, particularly in light of potential loss of revenues to MECO and the impact on the remaining ratepayers, and approved the contract.

As stated in response to CA-IR-11, MECO proposed the discount while also contemplating the installation of a utility-owned CHP system at a time closer to the need date for additional generation on the island of Lanai. The third party proposal was for a combination of CHP and customer-sited electrical generation, at a magnitude such that the customer would have completely bypassed the MECO system on the island and caused MECO to lose 40% of its Lanai sales. Thus, MECO's options to respond to the situation were to offer the discount, and help facilitate the installation of a number of energy conservation measures, to defer the customer's CHP project, and to encourage the customer to plan a CHP project (whether utility, third-party, or customer owned) that would be better sized and timed to fit with the island's overall generation needs.

Q. In CA-T-1, page 43-44, the CA takes the general position that unbundling the current rate structure would be a better mechanism for dealing with the situation such as that on Lanai. Does HECO agree with this position?

A. No. Unbundled rates would not have addressed the unique situation that occurred on Lanai, whereby a major customer contemplated bypassing the utility system for a significant portion of its load, which would have resulted in a significant loss of sales to the utility, and would have adversely impacted the rates for the remaining customers on the system. If the customer bypassed the utility system, then it would not be relevant whether the rates were unbundled or not – the customer would not be taking service from the utility and consequently there would be no revenue stream to the utility.

FINAL COMMENTS: THE ULTIMATE OBJECTIVE OF COMPETITION IS TO BENEFIT CONSUMERS, NOT COMPETITORS

Q. Do you have any final comments regarding whether the electric utility should be allowed to own CHP and DG?

A. Utility-owned CHP and DG can provide significant benefit to both participating and non-participating customers. Some of the parties to this docket have raised concerns about the impact utility participation will have on the competitive DG market in Hawaii. However, these parties appear to be raising concerns about competition primarily from a theoretical standpoint and from the viewpoint of non-utility DG developers and equipment vendors, not energy consumers. Contrary to this viewpoint, the overarching objective of competition is not to protect the interests of competitors, but the interests of consumers.

Utility owned customer-sited DG, properly structured and regulated, will benefit Hawaii energy consumers. The proposed utility CHP Program provides another option for customers and meets a customer desire, all the while allowing for fair competition in cogeneration project development and equipment sales.

Providing customers with as many choices for CHP as possible maximizes competition. Allowing the utility to directly participate in the CHP market provides an alternative CHP model that customers may find attractive, depending on their particular priorities or objectives. Utility-owned CHP provides the most benefits to the broader base of ratepayers, however, individual CHP customers are free to decide whether or not to develop CHP with a non-utility provider.

With respect to the DG/CHP market in Hawaii, the interests of energy consumers – including non-participating customers – should be paramount. Vendors and developers must have suitable competitive opportunities to sell their equipment or offer their services; however that should not come at the expense of Hawaii's energy consumers as a whole.

In this case, however, both manufacturers and energy services companies would ultimately benefit by having the utility directly involved. Host CHP customers would benefit from the proposed utility CHP Program. Non-participating customers would also benefit.

The electric utility, overseen by the Commission, should be directly involved in developing and owning CHP and DG projects.

Q. Does this conclude your testimony?

A. Yes, it does.