TESTIMONY OF
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HAWAIIAN ELECTRIC COMPANY, INC.

Subject: DG Application and Technologies, HECO Consideration of DG, HECO Participation in CHP, Hawaii CHP Market, Customer Support for HECO CHP Involvement, Impact on Competition, Current HECO CHP Activities, Externalities, IRP

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. My educational background and experience are given in HECO-100.

Q. Mr. Seu, have you previously testified before the Public Utilities Commission?

A. Yes, I served as a witness in Docket No. 97-0102 (HCPC Complaint), Docket No. 97-0346 (MECO 1999 Test Year Rate Increase), and Docket No. 99-0207 (HELCO 2000 Test Year Rate Increase).

Q. What is your understanding of the purpose of the proceeding?

A. As stated by the Commission in its order instituting a proceeding to investigate distributed generation in Hawaii, the purpose of this proceeding "is to examine the potential benefits and impacts of distributed generation on Hawaii's electric distribution systems and market." (Order No. 20582, issued October 21, 2003.)

Q. What are the issues in this proceeding?

A. The issues are those set forth in Prehearing Order No. 20922, issued April 23, 2004. As stated in Prehearing Order No. 20922, there are 13 planning, impact and implementation issues. Briefly, these are:

Planning Issues:

Issue #1: What forms of distributed generation (e.g., renewable energy facilities, hybrid renewable energy system, generation, cogeneration) are feasible and viable for Hawaii?

Issue #2: Who should own and operate distributed generation projects?

Issue #3: What is the role of the regulated electric utility companies and the Commission in the deployment of distributed generation in Hawaii?

Impact Issues:

Issue #4: What impacts, if any, will distributed generation have on Hawaii's electric transmission and distribution systems and market?

Issue #5: What are the impacts of distributed generation on power quality and reliability?

Issue #6: What utility costs can be avoided by distributed generation?

Issue #7: What are the externalities costs and benefits of distributed generation?

Issue #8: What is the potential for distributed generation to reduce the use of fossil fuels?

Implementation Issues

Issue #9: What must be considered to allow a distributed generating facility to interconnect with the electric utility's grid?

Issue #10: What is the appropriate rate design and cost allocation issues that must be considered with the deployment of distributed generation facilities?

Issue # 11: What revisions should be made to the integrated resource planning process?

Issue #12: Same as Issue #1.

Issue #13: What revisions should be made to state administrative rules and utility rules and practices to facilitate the successful deployment of distributed generation?

Issue #14: The Commission has also allowed the parties to address general issues regarding distributed generation raised in the informal complaint filed by Pacific Machinery, Inc., Johnson Controls, Inc., and Noresco, Inc. in July 2003.

Q. What is the scope of your testimony?

A. I will provide testimony on the following subjects:

1) DG Application and Technologies
2) HECO Consideration of DG
3) HECO Participation in CHP
4) Hawaii CHP Market
5) Customer Support for HECO CHP Involvement
6) Impact on Competition
7) Current HECO CHP Activities
8) Externalities
9) IRP

Q. What other testimonies do the Companies present to support their application in this proceeding?

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

Witness Number	Witness	Subject
HECO T-2	Arthur S. Seki Director, Technology HECO	Renewable Distributed Generation, Differences Between Commercial Wind Farm and Small Distributed Generation Wind Turbine Applications, Discussion on Renewable Technology Feasibility and Viability, and Policies and

		Incentives for Renewable Energy Development
HECO T-3	Ross H. Sakuda Director, Generation Planning HECO	Generation Avoided Costs, Need for Utility Combined Heat and Power ("CHP") Capacity, Distributed Generation ("DG")/CHP and Integrated Resource Planning, Reserve Capacity, Spinning Reserve and Operating Reserve, and Reduction in Fossil Fuel Use
HECO T-4	Shari Y. Ishikawa Director, Transmission Planning HECO	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 T-5	Estrella A. Seese Director, Pricing HECO	Rate Design
HECO T-6	William A. Bonnet Vice President, Government and Community Affairs HECO	Regulatory Policy Matters

I will discuss Issue Nos. 1, 2, 7, 9 and 11 and part of issue No. 4. Mr. Sakuda addresses Issue Nos. 6, and 8. Ms. Ishikawa will address Issue Nos. 5 and 9, and parts of Issue Nos. 4 and 6. Ms. Seese will address Issue No. 10. Mr. Seki addresses renewable DG. Mr. Bonnet will address Issue Nos. 3, 13, and 14.

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.

DG APPLICATIONS AND TECHNOLOGIES

Q. Issue No. 1 addresses the forms of distributed generation (e.g., renewable energy facilities, hybrid renewable energy systems, generation, cogeneration) that are feasible and viable for Hawaii. (Issue No. 12 is identical to Issue No. 1.) What is distributed generation ("DG") within the context of this docket?

A. DG, as described in Order No. 20582 of this docket, involves the use of small-scale electric generating technologies installed at, or in close proximity to, the end-user's location.

Q. Is there a specific size limit to DG?

A. We have not defined a discreet limit, but recommend that "small-scale" be construed relative to the utility's system loads and to the loads of large customers. For example, a 5 MW unit might be considered DG on Oahu, but on Molokai or Lanai this size of a unit would be akin to a central station power plant and not DG. As an additional example, we have stated that large-scale cogeneration should not be considered in the distributed generation proceeding, since in general, large-scale cogeneration projects are like central station generation. These facilities are large sized and designed to provide significant export power to the electric grid at the transmission level, as opposed to being smaller and sized to meet individual customer loads or feed a distribution circuit. New cogeneration projects in this large-scale category would be of sufficient magnitude to require individual project or purchase power agreement applications with the PUC for review and approval.

Q. How has DG been applied in Hawaii?

A. DG uses in Hawaii have included:

1) customer-sited emergency generation;
2) substation-sited peaking generation;

3) substation-sited generation to address a case-specific transmission problem;

4) commercial customer-sited generation for combined heat and power ("CHP") systems;

5) industrial customer-sited cogeneration;

6) off-grid, customer-sited generation for electricity power purposes; and

7) customer-sited generation, operated in parallel with the utility grid, for electricity power purposes only.

These are the seven DG applications that are identified in our Preliminary Statement of Position ("Preliminary SOP") filed May 7, 2004 in this docket.

Q. Can you describe an example of each application?

A. An example of application 1, customer-sited emergency generation, is a hotel that has its own emergency generator, which is used by the hotel during power outages. Application 2, substation-sited peaking generation, was seen at HELCO when the utility installed four 1-MW generators at substations to help meet system peak power needs. An example of application 3, substation-sited generation to meet a case-specific transmission problem, is MECO's Hana generators, wherein two generators were installed in a remote location that is fed by a limited number of transmission lines. Application 4, CHP, where the waste heat from a distributed generator is captured for cooling or heating purposes, is seen at the Grand Wailea on Maui. Industrial customer-sited cogeneration, application 5, is seen at the two oil refineries on Oahu. Application 6 would be a customer that is entirely self-generating and not connected to the utility grid. Finally, examples of application 7, customer-sited generation operated in parallel to the grid for electricity power purposes only (i.e. no cogeneration or CHP), are the numerous residential photovoltaic systems.

Q. What is the Companies' definition of feasible and viable as it relates to DG technologies for Hawaii?

A. In order for a form of DG to be "feasible and viable for Hawaii", it 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.

Q. Can you define each of these criteria?

A. This is a brief description of our definitions for each criteria:

1) Technically feasible: when that technology has been built, tested, and considered as a proven technology by industry peers.

2) Commercially available: when DG equipment of that technology is listed in a reputable manufacturing company catalog with the ability to order multiple units of that equipment along with O&M procedures and product warranties. Prototype equipment would not be considered to be commercially available.

3) Economically viable: when DG life cycle costs are lower or relatively low when economically compared with other energy options.

4) Price competitive: when the costs of meeting the "customer's" energy needs from DG are comparable to the customer's costs of other forms of energy sources.

5) Sustainable: sufficient infrastructure and product support are available to keep the DG installation operating over the long-term.

6) Able to address site-specific constraints: the DG can be installed, operated, and maintained within the specific constraints of a project site, for example due to limited space, sensitive neighbors, environmental permitting restrictions, etc.

7) Able to meet the needs of customers: the DG application must be appropriate to the customer need, which will vary depending on such factors as the nature of power usage and customer type.

Q. What distinctions are you trying to make when you list "economically viable" and "price competitive in the short-term" as separate considerations?

A. The term "economically viable" takes into account longer-term cost considerations. In looking at DG options, utilities tend to focus on economic viability, since they compare options on the basis of life-cycle and planning period costs, stated on a net present value basis. The "planning period" for utility commercial customers, who represent the market for the larger DG applications, tends to be relatively short. Thus, the term "price competitive in the short-term" refers to the tendency of purchasers to look at up-front costs and pay-back periods in determining whether to make investments, even though more costly investments may tend to be more cost-effective in the long-term.

Q. Are the forms of DG (i.e., DG technologies) that are "feasible and viable" the same for all applications of DG?

A. No. They may differ depending on the intended application. It is also important to recognize that for customer-sited DG applications, the decision to install customer-sited generation will be made by the customers allowing the installation of such generation. Thus, customers making up this market will determine whether a form of DG is "feasible and viable for Hawaii".

Q. What DG technologies are there?

A. DG technologies that are fossil-fuel based include internal combustion engines, combustion turbines, microturbines, and fuel cells, although some classify fuel cells as renewable given the potential for them to run on hydrogen generated from renewable resources. DG technologies that are renewable include wind turbines and photovoltaics. These technologies are described in more detail in Exhibit 101.

Q. Which of these are most commonly used?

A. Currently, internal combustion engines are the most commonly used type of DG technology, primarily because of the maturity of the technology, their availability in a wide range of sizes from under 10 kW to over 10 MW, and their relatively low cost. Combustion turbines are commercially available, but since they are typically above 1 MW in size, they are not as commonly used as the internal combustion engine. Microturbines and fuel cells are still in the formative stages of the product development cycle and their use is very limited.

Q. What about the renewable technologies, wind turbines and photovoltaics?

A. Both technologies are commercially available and in use. However, they are not as common in small-scale DG applications as internal combustion engines, either because of practical siting challenges for wind turbines, or relatively high costs of photovoltaics.

The current state of development and application of the renewable DG technologies, including fuel cells, is described in more detail in the written direct testimony of Arthur Seki, HECO T-2.

Q. For the commonly used fossil fuel DG technologies, what fuels are available in Hawaii, from the standpoint of having existing infrastructure to supply the fuel on a long-term basis?

A. Internal combustion engines and combustion turbines can be fired on diesel, propane, natural gas, or synthetic natural gas ("SNG"). Of these, only diesel, propane, and SNG are available on a "macro" basis in Hawaii, although SNG is not available on all of the islands. On a project-specific basis, the particular fuel used for a DG installation will depend on the technical and economic feasibility of connecting into an existing fuel supply system or constructing a new one, site specific permitting constraints (e.g. for air permitting), and the overall economics of the project.

Q. What are the characteristics of and permitting requirements for the various DG technologies?

A. We prepared a chart in response to CA-SOP-IR-5 (on page 3) indicating the characteristics, costs and resource requirements for various DG technologies, which is reproduced as Exhibit 102 to my testimony. The data included in the table is intended to be representative of the technologies, without being a comprehensive or definitive comparison of the technologies. Possible permitting requirements, which will vary depending on the DG technology, fuel type, and site location and conditions, are described in the response to CA-SOP-IR-5, pages 4-8.

Q. Can you summarize the primary positive and negative factors, including externalities, for the four available DG technologies -- internal combustion engines, combustion turbines, wind turbines, and photovoltaics?

A. For internal combustion engines, the primary plusses are their relative low cost, technological maturity, availability in a wide range of sizes, durability, broad number of suppliers, and relatively compact size such that they can be installed in a small "footprint." Internal combustion engines are also firm sources of power.

The negatives for internal combustion engines are primarily associated with environmental issues – emissions, noise, fuel spills, and aesthetics of an exhaust stack. Combustion turbines generally have similar positives and negatives as the internal combustion engine, with the exception that they are not as available in small sizes and from as many manufacturers.

With regard to wind turbines and photovoltaics, the primary positive is that they are renewable, meaning no emissions and no fuel infrastructure is required. Additionally, wind turbines are generally cost effective. The primary negatives for wind are that it provides intermittent energy and it is more limited for DG application due to siting constraints, since adequate wind resources do not always exist at a DG site or the installation of a wind turbine may not be suitable for a dense urban environment where DG is desired. Wind power also has some negative externalities such as aesthetics, noise, and bird strikes. Negatives for photovoltaics are its intermittent energy and its high cost.

Q. With respect to the seven DG applications described earlier, are there any that require a specific DG technology to be used?

A. Yes. The DG applications involving cogeneration or CHP implicitly require a source of combustion heat. These applications will involve the use of internal combustion engines or combustion turbines, and possibly microturbines should they become more commercially available. When internal combustion engines or combustion turbines are used in a CHP application, an additional and significant positive is the very high efficiency of such a system.

HECO CONSIDERATION OF DG

Issue #2

Q. Issue No. 2 addresses who should own and operate distributed generation projects. What are the ownership (and operation) options?

A. In response to Issue No. 1, the Companies have identified seven categories of DG applications. The ownership and operation and maintenance (O&M) options for each DG application are as follows:

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).

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.

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

A. The Companies plans with respect to the seven DG applications 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. What are the potential benefits of DG to the Companies with respect to the deferral of new utility facilities?

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. Ross Sakuda at

HECO T-3 provides detailed testimony on the deferral of new central station generating capacity and the displacement of utility central station generation fuel and variable O&M costs. Shari Ishikawa at HECO T-4 provides detailed testimony on deferral of new transmission and distribution ("T&D") capacity and impacts on T&D system reliability and power quality.

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 benefit by retaining the customer load and avoiding uneconomic bypass. Testimony is provided below discussing one such instance -- the Companies' application of CHP systems at customer sites. Such a utility DG program would benefit HECO and its ratepayers.

<u>HECO PARTICIPATION IN CHP</u>

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 system are detailed in the Companies' CHP Application:

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.

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. What quantitative analysis have been done to show that the Companies' proposal to offer CHP Programs 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 are addressed by Mr. Sakuda 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. Can you cite an example where a non-utility CHP project would have been detrimental to other electric customers?

A. Yes. A third party CHP proposal to Castle & Cooke Resorts on Lanai is a case in point. As described in Maui Electric Company's Application for Approval of a Service Contract with Castle & Cooke Resorts, LLC in Docket No. 03-0261, the non-utility CHP proposal was to add approximately 12 CHP and DG generators, with a capacity of over 5 MW, at the Manele Bay Hotel, Lodge at Koele, and Central Services. If the proposal had been implemented, 17 accounts representing approximately 40% of MECO's Lanai Division sales would have been taken off the grid. These sales that would be lost provide approximately $1.2 million annually toward MECO's fixed costs of serving Lanai. If the reduction in revenues for fixed costs were allocated to all of MECO's remaining customers on Lanai on an across-the-board basis, the result would be a rate increase of approximately 37% for remaining Lanai customers. (See MECO Application for Approval of Service Contract with Castle & Cooke, Docket No. 03-0261, pages 11-15).

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

A. Such 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.

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.

Q. From the standpoint of benefiting the overall utility electrical system, is there any difference between utility-owned and operated CHP versus non-utility CHP?

A. Yes. The ability of the utility to directly control the operations and maintenance of a CHP system will improve its impacts on system reliability and power quality.

Ross Sakuda at HECO T-3 describes this in more detail. In short, 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.

Q. Are there any utilities that offer utility-owned, operated and maintained CHP?

A. Austin Energy, a municipal utility serving 350,000 customers in the city of Austin Texas, installs, operates and maintains customer-sited DG and CHP. Several pages from Austin Energy's website are provided as Exhibit 103.

Q. Would the Companies offer CHP systems on an unregulated basis, if that is the only option?

A. 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. 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).

HAWAII CHP MARKET

Issue #4

Q. Issue No. 4 addresses the impacts if any, distributed generation will have on Hawaii's transmission and distribution systems and market. What are the potential impacts on the Hawaii electric market?

A. Depending upon who installs, owns and operates the DG system, the impacts on the Hawaii electric market are markedly different. If a third-party or a customer installs DG, the load to be served by the utility is reduced and the utility loses the portion of the rate normally charged to the customer to cover fixed costs. When that happens, those costs must be borne by other ratepayers when rates are adjusted at the next rate case. In the interim, the utility shareholders bear the loss. If the utility owns and operates the DG system, the loss of fixed costs is substantially reduced and the overall program costs and payments can be structured so that all parties (the utility, the customer, other ratepayers) are better off by having the project completed.

Q. As described above, the Companies' current DG focus is on customer-sited CHP. Why are the Companies focusing on this market?

A. The Companies' view of the CHP market has evolved over the past 4 to 5 years.

This evolution is summarized in Exhibit C to the CHP Program application.

Q. What is the Companies' assessment of the size of the CHP market?

A. To assess the CHP market potential in their respective territories for purposes of a potential CHP Program (in early 2003), each of the Companies started with a list of their largest customers (for Oahu, this was all customers with a demand greater than 400 kW). This level of demand was set based upon the initial assessment of the technology indicating that projects below about 200 to 250 KW would generally not be economical. Based upon their knowledge of the customer's operations, the Companies' account managers determined which of these large customers had a potential CHP application. The key determinants were the size of the customer's air conditioning load, the hot water or steam requirements of the customer, and the age of the customer's central plant. Once the reduced list was established, a probability was assigned to each customer to indicate the account manager's opinion as to the likelihood that a specific customer would be interested in a CHP program. Based upon information available from the customer such as the approximate age of the customer's central plant, a tentative date was assigned as to when CHP would make the most economic sense. This process yielded a likely number of kilowatts of CHP by year for each company.

The nature of the high probability customers was then reviewed to determine how a generic CHP system might be defined for analytical purposes. Rather than attempt to model each customer or a wide variety of customers, it was decided that it would be more practical to define a generic unit from which per kilowatt or per kilowatt-hour values could be derived for analytical purposes. Once the generic unit was defined, an analysis was done to define the total impact of the CHP program on the utility systems. The use of an absorption chiller displaces an electric driven chiller thereby reducing electrical load, and increasing the effective efficiency of the CHP system.

The final step in the process of assessing the CHP market was to determine the impact of the Companies' entry into the market. Based upon direct discussions with customers, HECO believed that utility participation in the market would result in more CHP being developed overall. Third parties were expected to continue to participate in the market, however. This resulted in the CHP market forecast that ultimately was filed in the Companies CHP Program application in Docket No. 03-0366.

Q. Have there been any updates to this CHP market forecast?

A. Yes, within the context of HECO's IRP-3 process. During the IRP process the numbers from the CHP Program application forecast were increased. This reflected new knowledge regarding the potential for several large CHP system projects, delays in starting the CHP Program, and the sentiment of the IRP CHP Technical Committee that HECO's CHP Program application forecast was too conservative. This HECO IRP CHP forecast is provided as Exhibit 104.

Q. What was the basis for the higher IRP forecast?

A. Numbers representing several potential larger projects were added in years 2005 to 2009. These projects are for construction of new facilities or for expansion of existing facilities of several large customers. For example, one that is widely known is the Outrigger Beachwalk project in Waikiki. These projects were not included in the CHP Program application forecast since that forecast focused on retrofits of existing installations. In addition, 200 kW in additional CHP was added to each year beyond 2010, to reflect the feeling of the IRP CHP Technical Committee.

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, and as described below in specific examples. 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, the Companies believe that 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. Would this increased market also be achieved if the Companies simply serve a facilitating role, without actually offering CHP themselves?

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.

CUSTOMER SUPPORT FOR HECO CHP INVOLVEMENT

Q. Please describe in more detail the customer support for the Companies' CHP offering.

A. Certainly. First I'll describe general support from several customers, and then describe the interest that has led up to some specific potential CHP projects.

Q. In the Companies' General Response to Informal Complaint No. IC-03-098, Appendix B to Part I, comments from the following four customers were provided indicating their strong support for the Companies' involvement in CHP:

- Outrigger Hotels & Resorts
- Mauna Kea Beach Hotel/Hapuna Beach Prince Hotel
- Hawaiian Building Maintenance, Manager of Harbor Court
- Grand Wailea Resort.

One of the common reasons for support from these customers was the sentiment that the utilities' involvement provides more choices and options among CHP vendors, and by doing so this maximizes competition in the market. Another common reason for support was the desire to work with a company with a strong, reliable, local presence. The comments are provided as Exhibit HECO 105.

Another key factor in the favorable response of most customers has been the fact that CHP is simply one of the options the utility considers in helping the customer seek optional energy efficiency. Customers seem to appreciate the fact that the utility is not in the equipment sales business and will, consequently, also evaluate other options such as the installation of energy conservation measures, tailored to the unique needs of the customer and facility.

IMPACT ON COMPETITION

Q. The customer perspective described above was that utility involvement would enhance competition in the CHP market. Please describe the Companies' position on how its participation would impact competition in the CHP market.

A. As stated in the Companies' CHP Program application in Docket No. 03-0366, the

Companies' proposed CHP Program will 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. There are distinct differences between the Companies' CHP program offerings and those of non-utility vendors, and customers should be allowed to choose between such offerings.

Q. How do the utility and non-utility offerings differ?

A. Non-utility CHP vendors typically offer the following in their proposals:

- Electrical capacity (in some cases) that is equal to the customer's peak requirements;
- A direct equipment sale or relatively short term operating lease (usually seven years);
- Shared savings based upon historical energy consumption;
- Equipment maintenance.

In contrast, the Companies' proposed CHP Program includes the following key elements:

- Electrical and heat capacity based upon the customer's continuous base heat load;
- Utility owned, operated and maintained system for a 20 year term;
- Defined savings based upon a discount from the customer's standard tariff for power generated on site.

There is enough differentiation between the utility's CHP offerings and those of the non-utility vendors, such that the utility CHP offering truly represents another distinct option for customers. In a competitive marketplace, customers should be given the opportunity to consider as many options as possible.

Even with these differences, non-utility vendors are still 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.

Q. Non-utility vendors, specifically energy services companies ("ESCOs"), have traditionally offered complete central plant services. Does the utility plan to offer such services beyond the CHP system, specifically installing, owning, operating and maintaining the balance of central plant equipment?

A. Although some customers have asked us this question causing us to give it consideration, the Companies do not intend to extend the own-operate-maintain model to central plant systems beyond the primary components of the CHP system, which are described on page 42 of the Companies' CHP Program application in Docket No. 03-0366 as: (1) the generating units with waste heat recovery modules, (2) an absorption chiller, (3) a heat exchanger for heating water, and (4) a cooling tower.

Q. What is the basis for this position?

A. We have stated that offering CHP is a natural evolution of electric utility services. Specifically, the utility has 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. We cannot, however, make the same arguments for the balance of central plant equipment.

Q. Will the ability of non-utility vendors to compete with the Companies' proposed

CHP programs be unduly impeded by a lack of access to customer information, or utility interconnection requirements, as some CHP system providers may have claimed?

A. No. Non-utility vendors have shown that they have enough access to customer information to offer CHP systems and/or DG to utility customers, and utility installations of CHP systems will meet the same Commission-approved interconnection standards that are applied to non-utility installations. In addition, the CHP Programs can and should create a larger market for CHP systems. Unregulated competitors will have the opportunity to offer their products and services in that expanded market –without review of their prices, or terms and conditions of service by the Commission.

Q. Please describe the issue regarding access to information.

A. The most critical data required for a CHP proposal comes from the customer itself, not the utility's records. The electric utility has gross electrical consumption data on its customers, but generally has no more information unless it has previously worked with a customer. 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. 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 ESCOs who obtain detailed facility energy usage data in the normal course of their business.

Q. Is there an issue regarding interconnection standards?

A. There should not be. 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 be subject to the same review and study process, as non-utility CHP installations.

Q. What about standby charges? Haven't others alleged that HELCO's Rider A, Standby Service, would give HELCO's CHP an unfair advantage?

A. The complainants in Informal Complaint No. IC-03-098 did indeed raise this concern. In response, the Companies pointed out that the 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, they may well be able to obtain backup service at lower cost than under HELCO's regular rate schedules.

Ms. Seese, in HECO T-5, explains 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.

Notwithstanding this, HELCO does appreciate the unresolved nature of the concerns raised on standby charges. 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. What is the Companies' current position regarding the "sole supplier" of electricity clause that was envisioned in its CHP Program application?

A. The Companies have reconsidered this clause and will delete it from its standard Cogeneration Energy Purchase Agreement.

Q. Please summarize the Companies' position regarding the impacts of the utility CHP program on competition.

A. Taking the above issues together, the Companies believe that their direct participation in the CHP market will serve as another competitive option for customers to consider. The Companies' CHP offerings are different from others, and more limited in scope compared to ESCO's who would look to providing complete central plant services. The Companies do not enjoy any unfair advantage in terms of access to customer information or application of interconnection standards.

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.

CURRENT HECO CHP ACTIVITIES

Q. What are the Companies currently doing to pursue CHP?

A. In addition to participating in the Generic Distributed Generation Docket No. 03-0371 and filing for Commission approval of their CHP Programs in Docket No. 03-0366, the Companies are continuing to develop selected CHP projects for customers, with the full understanding that for individual CHP projects to be installed via special service contracts, Commission approval is required under Rule 4 of the Companies' tariffs. Additionally, the Companies are developing a new CHP equipment procurement process that will be used on a going-forward basis.

Q. Have any CHP proposals been made to customers?

A. The Companies have made a number of proposals to customers to install and operate utility-owned CHP systems at the customers' sites, and have executed a number of letters of intent and memoranda of understanding to conduct preliminary engineering for potential CHP projects. (See Response to LOL-SOP-IR-82, page 20.) Any contract resulting from the proposals would be subject to PUC approval under a Company's Tariff Rule No. 4, or would be filed under a Company's Schedule CHP (if the tariff is in effect and the project is within the scope of the tariff).

Q. Given the status of the ongoing dockets, why would the Companies actively pursue CHP projects via Rule 4 approval at this time?

A. The Companies are developing a limited number of CHP projects for consideration by the Commission under Rule 4 primarily where there is special urgency on the customer's part to implement the project. For example, a facility may be undergoing major renovation or expansion such as the Outrigger

Beachwalk, and implementation of a CHP system is best done at the same time as a new central plant is constructed.

Q. Please explain in more detail why the Companies are designing a new CHP equipment procurement process, especially given its existing Hess teaming agreement.

A. With the growing interest in CHP in Hawaii, the Companies became aware of the potential for some CHP projects that will likely require larger units than are covered by the HECO-Hess teaming agreement. Given this potential, as well as the sensitivity expressed by some parties in this docket regarding the ability of CHP vendors to compete for projects, the Companies felt it appropriate at this time to develop and implement a new CHP procurement process.

Q. What will be the objectives of the new process, and what will it look like?

A. 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.

As for the process itself, we are still in the stages of developing it but we are considering use of elements from various approaches to procurement, including pre-qualifying bidders, use of strategic alliances, and equipment bidding. The appropriateness of approach will depend somewhat on the project itself. 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 via a strategic alliance with a qualified vendor of packaged systems.

Q. What will be the impact on the HECO-Hess teaming agreement?

A. We have already had discussions with Hess about the need for the new procurement process, and they are agreeable to subject their products and services to the new process on a going-forward basis. Hess, like other equipment vendors, believes in its product and is willing to go through the new process. We have not yet formally terminated the teaming agreement, as we are working with Hess to identify which existing projects HECO and Hess will continue to work on together.

Q. Does any of this change HECO's position regarding the justification for initially entering into the HECO-Hess teaming agreement?

A. No. As described on pages 45 to 48 of the Companies' CHP Program application in Docket No. 03-0366 and attached hereto as Exhibit 106, the Companies considered a number of vendors and entered the agreement with Hess because of their demonstrated leadership in installing CHP systems in Hawaii and because Hess' packaged CHP system approach was appropriate for the CHP program that the Companies envisioned. The use of small packaged CHP systems continues to be a central element to the Companies' CHP Program, but it is clear that there will also be cases where small packaged CHP may not be the best solution, such as with very large installations of several megawatts. Our new procurement process will be broad enough to cover the range of CHP projects that may arise. To the extent Hess continues to be the most appropriate vendor of small packaged systems, the new procurement process will identify this.

Q. Has HECO made any conclusions at this time as to whom its future vendors will be?

A. No. To do so would be premature. We will finalize our new procurement process, and then implement it.

EXTERNALITIES

Issue #7

Q. Issue No. 7 addresses the externalities costs and benefits of distributed generation. Are there externality impacts associated with DG?

A. Yes, just as there are impacts associated with any form of generation. Distributed generation brings both positive and negative externality impacts, as described below. Many of the negative externalities, however, can be mitigated by proper design and siting.

Q. What positive "externalities" are associated with DG?

A. The positive externalities of distributed generation include the following:

1) Ability to meet specific needs of an energy user. Distributed generation, in particular that which is installed at an end-user's site, can be tailored to meet specialized energy needs. For example, distributed generation can provide backup or premium power to meet reliability or power quality needs of a facility. In another instance, a facility with sufficient thermal loads may be able to utilize a combined heat and power system to achieve greater energy efficiency and energy savings. The flexibility and variety of distributed generation systems and applications is a key benefit.

2) Fuel efficiency/avoidance of fossil fuels. Distributed generation from renewable energy directly avoids the burning of fossil fuels. Additionally, certain types of distributed generation that use fossil fuels can be highly efficient, such as combined heat and power. The thermal efficiency of fuel

usage in a combined heat and power system typically ranges from 85% to 90%, versus 35% to 40% for a conventional central station generating unit. Distributed generation of all types can reduce transmission line losses, providing additional efficiency improvements.

3) Scale. The smaller scale of distributed generation provides an enhanced ability to switch to new technologies due to lower incremental costs (i.e. avoidance of a single large investment).

Q. What negative externalities are associated with DG?

A. Negative externalities of distributed generation are chiefly in the area of environmental externalities, as described below:

1) Air emissions. Distributed generation that is based on fossil fuels- reciprocating engines, combustion turbines, microturbines- brings with it associated emissions, including NOx, SO2, CO, and CO2. One concern that has been raised is that to the extent DG is located closer to the locations of load demand than central station power generation, there will be greater likelihood of a populace being exposes to DG emissions. However, this is mitigated by the fact that DG installations and their emissions are much smaller in scale compared to central station power plants. Additionally, emissions impacts from DG can be mitigated with appropriate emissions controls, good engineering practice design of exhaust ducts, and/or operational measures to assure efficient combustion of fuel. The Hawaii Department of Health regulates emissions via its noncovered source and covered source air permitting rules.

2) Noise. Distributed generation that employs moving machinery – reciprocating engines, combustion turbines, microturbines, and wind

turbines – emits noise. Given that DG may be sited at the distribution level of a power grid in residential and commercial areas, there will naturally be more sensitivity to noise impacts than for a central station power plant located in an industrial area. In Hawaii, there are fairly strict noise standards for residential areas. The Hawaii Department of Health regulates and enforces these standards.

3) Visual impact. Distributed generation may bring both positive and negative visual impacts. Visual impacts can be positive from the perspective that if transmission infrastructure can be deferred or obviated, the visual impacts of that infrastructure can be avoided. Impacts can be negative if the distributed generation installation itself is visually obtrusive, such as may be the case with wind turbines, photovoltaic arrays, or exhaust stacks.

IRP

Issue #11

Q. Please respond to Issue No. 11, which addresses revisions that should be made to the integrated resource planning process.

A. The Companies' position is that no changes to the IRP Framework are required for the consideration of distributed generation.

DG and CHP technologies are being analyzed extensively in the current HECO IRP. The biggest challenge in this analysis is that by its nature IRP analyzes resources at the system level prior to identification of specific projects. Additionally, individual DG/CHP projects are generally too small to impact the timing of central station generation or transmission line additions. For these reasons, DG and CHP must first be considered on a generic basis and the site-specific impacts a particular project may have on the system are not considered. A generic DG/CHP forecast for the HECO system must be developed, as was done for the HECO CHP Program application in Docket No. 03-0366.

FINAL COMMENTS

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

A. If CHP and DG is only to play a limited role in meeting the energy needs of a specific customer namely the CHP host, than arguably private non-utility developers might best develop CHP and DG. However, if CHP and DG is meant to also play a larger, broader role serving not only specific customers but also the entire electric customer base via its generation and T&D capacity benefits, than the electric utility, overseen by its regulators, should be directly involved in developing and owning CHP and DG projects.

Q. Does this conclude your testimony?

A. Yes, it does.