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PUBLIC UTILITIES COMMISSION

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

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| ---- In the Matter of ---- | ) | |
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| PUBLIC UTILITIES COMMISSION | ) | DOCKET NO. 03-0371 |
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| Instituting a Proceeding to Investigate Distributed Generation in Hawaii | ) | |
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HAWAII RENEWABLE ENERGY ALLIANCE'S PREHEARING CONFERENCE STATEMENT

AND

RESPONSE OF HAWAII RENEWABLE ENERGY ALLIANCE

TO

INFORMATION REQUESTS FROM THE PUBLIC UTILTY COMMISSION ON

DOCKET NO. 03-0371, IN THE MATTER OF PUBLIC UTILITIES COMMISSION

INSTITUTING A PROCEEDING TO INVESTIGATE DISTRIBUTED GENERATION IN HAWAII

AND

CERTIFICATE OF SERVICE

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF HAWAII

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| ---- In the Matter of ---- <br> PUBLIC UTILITIES COMMISSION <br> Instituting a Proceeding to Investigate Distributed Generation in Hawaii | ) <br> ) <br> ) <br> ) <br> ) <br> ) <br> ) | DOCKET NO. 03-0371 |

The Hawaii Renewable Energy Alliance (HREA) hereby submits its Prehearing Conference Statement and its Response to Information Requests (IRs) from the Public Utilities Commission ("PUC") on the instant docket, dated and submitted to the PUC on November 22, 2004 in accordance with the PUC's Prehearing Order Number 20922 (Reference Docket No. 03-0371).

## I. INTRODUCTION

HREA's Prehearing Conference Statement, prepared by its President (Warren S. Bollmeier II), is included in Section II. HREA received 34 IRs from the PUC. HREA's Response to the PUC IRs, also prepared by its President (Warren S. Bollmeier II), is included in Section III.

Please note that the IR format, including the category breakout, is as received from the Commission.

## II. PREHEARING CONFERENCE STATEMENT

The following is HREA's response to the items listed in the PUC letter dated November 1, 2004:

Witnesses to be Called

Mr. Warren S. Bollmeier II, President, HREA will appear as the witnesse for HREA. Mr. Bollmeier will represent HREA on the hearing panel, respond to all questions posed to HREA, and ask questions to other panel members, pursuant to the hearing panel format described in the PUC's letter dated November 16, 2004.

Exhibits, Schedules, and Summaries

No documents beyond those previously filed, including information responses, will be submitted by HREA during the hearing unless a question from the PUC or another party requires submission of additional documentation in order to be responsive.

Further Motions

No motions are outstanding.

Stipulations

HREA does not propose or request any stipulations for hearing purposes.

Settlement Discussions

HREA is not currently engaged in any settlement negotiations.

Estimate of Hearing Time

This issue is no longer applicable, due to the revised panel hearing format mentioned above.

## III. RESPONSE TO INFORMATION REQUESTS FROM THE PUC

**Statutory Authorizations**

**PUC-IR-1** **Do Hawaii electric utilities have authority under existing statutes and franchises to own distributed generation either directly or through an affiliate? If yes, please identify the specific statutes and franchises which authorize such activity. If no, please describe whether existing laws should be altered to permit utility ownership (either directly or through an affiliate) and if so, what changes are needed?**

HREA Response: HREA supports the County of Maui's ("COMs") position that Hawaii electric utilities do NOT have authority under existing statutes and franchises to own distributed generation directly. HREA would also like to note that Mr. Bollmeier, HREA's President, is not an attorney and has not engaged in an independent review of the franchises of HECO, HELCO, MECO and KIUC.

HREA does not believe the current statutes allow for public utilities to be directly involved in behind-the-meter DG. However, we believe that, if public utilities want to participate in the market for customer-sited DG, they have the right, though not spelled out in the HRS, to establish separately staffed, separately capitalized, unregulated affiliates for that purpose. We not believe changes in the statutes are needed to accomplish this result, but changes in the regulation of utilities to govern their dealings with affiliates would be appropriate.

**PUC-IR-2** **Are there any changes required to existing statutes, rules, or regulations to facilitate non-utility ownership of distributed generation ("DG") facilities?**

HREA Response: HREA recommends changes to utility ratemaking to facilitate non-utility ownership of DG, including elimination of the inter-class and intra-class cross subsidies, establishment of a voluntary consensus process to review and approve DG interconnection standards, development and implementation of reasonable standby charges, adoption and enforcement of standards concerning affiliate dealing, and evaluation and possible implementation of revenue cap performance-based ratemaking, as well as development of credit for non-utility-owned renewables for purposes of our state's RPS.

We believe all of these initiatives can be accomplished by the Commission via establishment and implementation of clear policies and adoption of new rules and regulations. HREA also supports COM recommendations for the establishment of impact fees/credits and county wheeling. Perhaps the COM could become a pilot application for impact fees and wheeling.

**PUC-IR-3** **What is the impact of Hawaii's net energy metering law, codified at Hawaii Revised Statutes ("HRS") § 269-101-111, (and recently amended this past legislative session to allow eligible systems of up to 50 kilowatts ("kW") to sell excess energy to the utility) on customer decisions to invest in DG? Should the existing 50 kW size limitation be increased to facilitate DG? Should the existing net energy metering law be expanded to include technologies other than those specified in the statute? Please identify any other changes that should be made to net metering laws, and why?**

HREA Response: Actually, Hawaii's net energy metering law does not allow customer-generators to "sell" excess energy to the utility. Specifically, net metering interconnection agreements are not power purchase agreements, but are better characterized as a power exchange agreements.

**Factors Influencing DG Customers**

In any case, there are a number of factors that do influence the customer's decision to invest in net metered DG including: (1) the diurnal and season variations of customer-generator's load and potential renewable resources; (2) the performance, reliability and maintenance requirements of specific DG, and (3) installed cost of the DG, taking into consideration any available tax credits from the state or federal governments, and/or rebates from the utility.

**Increasing the Eligible System Size**

HREA supports the increase of the 50 kW size limitation to 500 kW. This would allow more customers to participate in net metering, e.g., condominiums, small businesses, farms and government agencies. HREA believes that larger systems can meet the same safety and performance standards as the smaller systems, and thus not negatively impact the utility system.

**Expanding the Net Metering Law to Include Other Technologies**

At the present time, HREA does not support the expansion of the net energy metering law to include technologies other than those specified in the statute.

**Other changes to the Net Metering Law**

The current law specifies a monthly billing cycle/reconciliation period. HREA recommends that the customer-generator have the option of choosing an annual billing cycle/reconciliation period. The annual period will allow the customer-generator the best opportunity to size his net-metered system to take advantage of the month-to-month variations in system output, e. g., there is more sun in the summer, more wind during trade-wind periods, etc.

**Definition of Distributed Generation**

**PUC-IR-4** **Should the Commission define distributed generation – and if so, how should it be defined? Should the definition be flexible or specific as to size and technology? Should the definition identify "eligible" technologies – and if so, how would such a list be derived? Or should the definition be sufficiently flexible to apply to a range of DG technologies, both those currently feasible as well as those not yet developed?**

HREA Response: HREA believes that the Commission should define distributed generation, and that the definition should be flexible as to size and technology. As opposed to identifying "eligible" technologies, HREA suggests the definition focus on DG applications and include a list of typical technologies, but a list that is NOT all inclusive. For example, the list could include a range of DG technologies that are currently feasible (or in the market place), as well as those anticipated, but yet not developed, and those not known at the present time. HREA believes the following definition from our Preliminary Statement of Position meets these criteria:

> *"Distributed generation (DG) includes supply- and/or demand-side devices and measures that provide electricity, thermal and/or mechanical energy. These resources can be located on-site or nearby to users. They can be used to meet baseload power, peaking power, backup power, remote power, power quality, and cooling, heating and power needs. DG includes energy supply devices ("prime movers") for providing electricity, thermal, and/or mechanical energy to users from on-site or nearby locations, and energy storage and interconnection equipment needed to interconnect with customers and/or the utility grid. Examples of DG are wind turbines, biomass cogeneration, hydroelectric plants, photovoltaics, fuel cells, microturbines, reciprocating engines, and pumped hydro storage. DG also includes demand-side devices and measures including energy conservation and energy-efficiency."*

The following are additional definitions from our Preliminary Statement of Position, which support the DG definition above:

> *Energy conservation is those measures that preclude or avoid the need to generate electricity. These include: (1) alternative ways to heat water, e.g., solar hot water heaters for homes or other buildings, and high temperature systems for commercial or industrial uses (e.g., laundries, food processing, etc.), (2) alternative ways to condition the air in our buildings, e.g., solar air conditioning and seawater water air conditioning, and (3) a myriad of consumer-oriented approaches to conserve energy, e.g., turning lights off when they are not needed, opening windows instead of using air conditioning, consolidating home laundry to reduce the number of machine wash loads per week, using the sun to dry clothes, etc.*

> *Energy efficiency is those measures that reduce the amounts of electricity required to accomplish the same task by: (1) deployment of higher efficiency lighting, appliances, motors and other electrical equipment. Examples include use of compact fluorescent lights, higher efficiency refrigerators and air conditioners, and various load management options; (2) load-shifting, e.g., the utility offers lower electric rates during off peak times to encourage shifting of loads and thereby*

*increase the overall system efficiency; and (3) upgrading the utility infrastructure with more efficient components and equipment to reduce line losses, e.g., higher capacity transmission lines and higher-efficiency transformers and switchgear.*

**PUC-IR-5** **Should the definition of distributed generation include DER, "distributed energy resources" and other demand side technologies or systems?**

HREA Response: HREA supports the inclusion of "DER, distributed energy resources, and other demand side technologies or systems" in the definition, as noted in the suggested definition above. HREA realizes that this definition may to beyond that developed in other jurisdictions, but believes this broader definition is important for the following reasons:

1. The energy stakes are high in Hawaii and we need to consider all options in meeting our energy needs;
2. Energy conservation and energy efficiency DG technologies are often the most cost-effective options to reduce or meet energy needs. HREA observes that we should not be encouraging the development of an electricity-generating DG option, at the expense of a more cost-effective measure for avoiding the need of electricity. For example, we should not encourage installation of CHP to provide electricity to operate inefficient appliances, lights and other devices; and
3. Incentives to meet RPS and other energy goals should be evaluated keeping all DG technologies in mind.

**PUC-IR-6** **Should the Commission draw a distinction between "small scale" DG and other DG resources and if so, why? How should "small scale" DG be defined? What benefits can small scale DG offer (e.g., firm power, increased reliability, reduce transmission constraints) and what impacts does it have on the system?**

HREA Response: HREA believes that all DG should be viewed as small-scale. Following the lead of IEEE 1547 Standard for Interconnection of DG, which currently covers electricity-generating facilities up to 10 MW, 10 MW could serve an upper threshold for DG subject to negotiation of interconnection agreements with the utility. HREA realizes that there may be some applications, for example, on a highly loaded distribution line, where DG facilities may need to be limited to less than 10 MW.

**Additional Information on "Viable and Feasible DG" for Hawaii**

**PUC-IR-7** **Please comment on HECO's listed criteria (see e.g. Seki Testimony at 20) for determining whether a DG technology is "viable and feasible" for Hawaii. Should other factors be considered as well?**

HREA Response: HREA observes that the HECO's listed criteria are from the utility's perspective, and consequently we believe these are the criteria HECO would consider before implementing utility-owned DG. However, these are not necessarily the same criteria that a customer would review before making a decision to invest in a DG. Ultimately, it is the customer that determines what is viable and feasible in Hawaii. For example, Hawaiian customers may choose to: (1) referencing Seiki's items 1 and 2 (technical feasibility and commercial availability), be an earlier adopter of a DG technology (such as fuel cells, which may have some initial technical problems in their early production phase), while a utility would most likely wait until a market becomes more established; (2) pay a premium price for a DG, such as PV, for non-economic reasons, such as protecting the environment, while the utility would be less likely to make a similar decision, and (3) referencing Seiki's items 6 and 7 (price competitive in the long-run and sustainable in the long run), purchase a CHP on a short-term contract, primarily because it will save them valuable energy dollars now, while the utility may only engage in DG facilities, such as CHP, that require (for various reasons) longer-term contracts.

**PUC-IR-8** **Have the "multiple benefits" of DG cited in Life of the Land's testimony (Wooley at 2) ever been quantified for Hawaii as they have in the other states mentioned in the testimony and if so, where can this information be found?**

HREA Response: DBEDT's Hawaii Energy Strategy and analyses in support of the State's RPS law included analysis of renewable technology options and future electricity costs, including projections of overall impacts on the state's economy. However, those studies are now dated. We would like to note in DBEDT's 2001 report on RPS ("Analysis of Renewable Portfolio Standard Options for Hawaii", see http://www.state.hi.us/dbedt/ert/shrep04/shrep04.html), there is a discussion in Appendix 2 of the economic analyses conducted by other states, such as Arizona, Minnesota, Nevada and Wisconsin in support of their RPS laws. Benefits highlighted included the number of jobs that would be created and revenues generated with implementation of RPS.

The Union of Concerned Scientists has conducted and updated extensive studies of the economic and environmental impacts of renewable energy. There are specific links to twelve states, but not including Hawaii. See http://www.ucsusa.org/clean_energy/renewable_energy/page.cfm?pageID=1505.

Finally, there have been some studies on the impact of windpower development with a focus on the mainland: (1) "Wind Turbine Development: Location of Manufacturing Activity," which can be downloaded from http://www.crest.org/index.html, and (2) Wind Energy and Economic Development: Building Sustainable Jobs and Communities (see http://www.awea.org/pubs/factsheets/EconDev.PDF).

HREA observes that the bottom-line in all of these studies is that renewables bring jobs and revenues to states.

**PUC-IR-9** **Please identify any additional information provided in response to any party's Information Requests or filed in other dockets that provides further documentation or evidence of:**

**a. whether there are transmission, distribution generation constraints which could be served by DG;**

HREA Response: We do not have anything to add to our testimony at this time.

**b. the extent to which load growth is driving the need for distribution system enhancements;**

HREA Response: We do not have anything to add to our testimony at this time.

**c. where DG should be located to be most effective (and documentation for this conclusion); and**

HREA Response: We do not have anything to add to our testimony at this time.

**d. the availability or feasibility of alternative technologies.**

HREA Response: We do not have anything to add to our testimony at this time.

**To the extent that your testimony or prior responses do not already provide sufficient detail on these issues, please supplement your testimony with information on the above points.**

**PUC-IR-10** **Please identify with specificity the type and size of DG that can be currently deployed in Hawaii to maximize the benefits and minimize costs.**

HREA Response: In order to answer this question, HREA would like to respond given two scenarios – first, the existing utility paradigm (including existing customer rates and power purchasing structures, and DSM programs), and second, a preferred future utility paradigm (including removal of customer-class subsidies, creation and sustaining a competitive market for all DG, and implementing enhanced DSM programs, which include pilot project for introduction of promising new DSM technologies).

**<u>Existing Utility Paradigm</u>.** The following DG are listed in rough order of their cost-effectiveness from highest to lowest:

- **Energy conservation DG:** solar hot water (residential), and solar hot water (commercial);
- **Energy-efficiency and Load-Management DG:** conventional DSM (higher efficiency lighting, appliances, motors and other electrical equipment), load control (switch on/off lights, etc.), heat pumps, and ice storage;
- **Energy Storage DG:** pumped hydro storage; and
- **Electricity-Generating DG:** CHP (diesel), CHP (propane), net metered wind turbines, net metered micro hydro, net metered biomass, and net metered PV.

**Preferred Future Utility Paradigm**. The following DG are listed in rough order of their cost-effectiveness from highest to lowest.

- **Energy conservation DG:** solar hot water (residential), solar hot water (commercial), solar air conditioning, and sea water air conditioning;
- **Energy-efficiency and Load-Management DG:** enhanced DSM (higher efficiency lighting, appliances, motors and other electrical equipment), load control (switch on/off lights, etc.), heat pumps and ice storage;
- **Energy Storage DG:** pumped hydro, advanced batteries, and hydrogen storage; and
- **Electricity-Generating DG:** net metered wind turbines, solar CHP, CHP (diesel), CHP (propane), net metered micro hydro, net metered biomass, micro hydro, net metered PV, fuel cells, and residential CHP.

**PUC-IR-11** **Identify with specificity existing environmental requirements which would impact the installation of DG and how this would occur? Are there any other regulatory requirements – <u>e.g.</u>, Building Codes or zoning laws that would impact installation of DG and if so, identify these with specificity.**

HREA Response: Wind energy projects are considered a pre-permitted use on private land, zoned agriculture, and do not require extensive environmental permitting. In the past, the Legislature has considered providing this same benefit to all renewable technologies. All projects, renewables included, must meet HRS Chapter 343 requirements if they are to be sited on state land, and projects on federal lands have similar requirements. All larger projects will typically require preparation and approval of an Environmental Impact Statement (EIS) in order to get a state or federal use permit.

HREA understands that smaller projects, such as CHP facilities, would not be subject to the same requirements. Some of the reciprocating engines come with pre-certification that they comply with federal air quality standards, but perhaps Hawaii should consider and adopt tighter standards for CHPs that are being operated near population centers. Bottom line is, there ARE already air quality requirements designed for central power plants but we certainly wouldn't want to see them LOOSENED for customer-sited CHP. Otherwise, we could end up with what the Pew Foundation called "smaller, closer, dirtier" generators than you have already."

**Impacts of Distributed Generation**

Identify the impacts of DG on the distribution system with reference to the following specific questions.

**PUC-IR-12** **What are the beneficial impacts of DG on the transmission and distribution ("T&D") system and more importantly, how may they be quantified and assessed for value?**

HREA Response: From page 8, lines 10 to 18, of our Preliminary Statement of Position (PSOP):

"We believe the impacts will be primarily positive, especially if DG is planned and implemented under IRP. For example:

- DG will help increase the overall reliability of our island grids, i.e., the addition of generators on the system increases reliability. Specifically, the probability of multiple generators failing at the same time decreases, improving reliability of the system. Also, individual failures will be mitigated to the degree that the DG will be smaller in capacity and their impacts will be less that larger generators (e.g., the loss of a 2 MW DG will much less of an impact of the loss of a 200 MW CG); and
- DG can be implemented to defer or avoid T & D upgrades and new T & D (such as with new construction of hotels and resorts)."

Also from our PSOP, page 10, lines 11 to 26, in response to this question posed by the PUC: "What utility costs ~~can~~ be avoided by distributed generation?"

"We believe there are a number of utility costs that can be deferred and/or avoided by DG including:

- Cost of new generation: If aggressively implemented, DG (as defined herein) and defer and possibly avoid the need for new CG. If implemented competitively (hence no rate-basing of DG), the utility costs for new CG can be avoided;
- Avoided line losses: implementation of DG will reduce line losses. Hence, utility costs associated with line losses can be avoided;
- Avoided T&D upgrades: similarly, implementation of DG, properly planned in IRP, will reduce the need for T&D upgrades. Hence, utility costs associated with T&D upgrades can be avoided; and
- Cost for spinning reserve: Spinning reserve can help improve system reliability and also provide load-following capability. Not

> all of the islands have a spinning reserve policy. With the installation and DG, it may be possible to reduce spinning reserve requirements, and those costs could be avoided by the utility."

In addition, the values of avoided T&D can be quantified, but we defer to others who may be able to provide those quantitative assessments.

**PUC-IR-13 What are the limits to the level of DG that the grid can absorb without adverse impacts? Please identify studies or other documentation in support of your response.**

HREA Response: HREA understands there may be limits to DG that are location-specific. However, we do not know that studies have been conducted to establish these location-specific constraints. Furthermore, HREA believes it could be hard to estimate how much DG each utility's grid can absorb without adverse impacts. It may also be likely that other constraints, such as customer interest, technology feasibility and viability, will limit the amount of DG before there are system constraints.

**PUC-IR-14 What are the limits of bi-directional power?**

HREA Response: Technically, there may not be any limits to bi-directional power. For now, there may be cost barriers to overcome. In Hawaii we have been experiencing/testing bi-directional power flows, e.g., due to the operation of previous and existing windfarms, biomass cogeneration facilities, and more recently with net metering. HREA believes that another test could come with the implementation of the virtual power plant concept, as proposed by the COM (reference COM-T-1, pages 16-17). HREA also observes that Portland General Electric ("PGE") Company's Dispatchable Standby Generation program appears to be a good example of the virtual power plant concept in operation. See:

http://www.portlandgeneral.com/business/large_industrial/dispatchable_generation.asp?bhcp=1

**PUC-IR-15 Should the design of new distribution feeders consider DG?**

HREA Response: Yes.

**PUC-IR-16 Can the concept of micro-grids be made practical? Can they be effectively utilized in Hawaii?**

HREA Response: The concept of micro-grids can be made practical. The National Renewable Energy Laboratory (NREL) has investigated the potential for micro-grids in residential applications. See these web-site links:

1) http://www.clean-power.com/research/microgrids/MicroGrids.pdf

2) http://www.clean-power.com/research/microgrids/MicroGrids2.pdf

3) http://www.clean-power.com/research/microgrids/NewHomeMarketReport.pdf

HREA also notes that the DG facility referenced in the Pennsylvania case (See HREA-RT-1, pages 10 and 11) is an example of micro-grid. Specifically, the facility will serve a number of customers within an industrial park.

HREA understands that the Hydrogen Power Park that is being designed for Kapolei Hale will be a microgrid.

At the present time, it is hard to estimate how many micro-grid applications there might be in Hawaii, but HREA believes there is enough opportunity in residential and commercial applications, that micro-grids should be encouraged.

**PUC-IR-17 Should utilities be offered incentives to facilitate DG?**

HREA Response: Yes. See HREA's PSOP page 7, where we suggest that the utility's role should be to facilitate DG, and that it may be appropriate to incentivize DG through a rebate program.

**PUC-IR-18 How can utility distribution practices be modified to enable DG to provide distribution deferral and be compensated for it?**

HREA Response: Yes. HREA supports the coordination of the planning for DG in the IRP process and utility DG planning. For example, any DG studies conducted by the utility should be included in IRP process. HREA also supports, as previously noted, the implementation of DG in utility DSM programs.

**Ownership**

**PUC-IR-19** **If utilities are permitted to own distributed generation through affiliates, are any changes required to existing statutes, rules and regulations governing affiliates to guard against cross subsidization, to protect ratepayers and ensure competition between affiliates and non-affiliates on equal footing? Please identify potentially applicable statutes, rules and regulations and specify necessary changes.**

HREA Response: From page 6, lines 8 to 13, of our PSOP:

"Thus, we believe that the regulated utility, if they wish to participate in the DG market, should be required to set-up an un-regulated utility entity completely independent of the regulated utility, with appropriate firewalls erected and enforced. The un-regulated utility entity would then compete with our energy service providers. The end-user might choose to own and operate the facility, or choose to own and then contract an energy service provider to operate the facility."

HREA recommends that rules and regulations relating to affiliate transactions should be examined in a separate rulemaking docket. In addition, the utilities should be required to make the books and records of affiliates with which they do business open to the Commission and Consumer Advocate during rate cases in order to ensure proper cost allocations have been observed and enable the examination of possible subsidization of the affiliate by the utility.

**Interconnection**

**PUC-IR-20** **What costs are associated with DG interconnection to the distribution grid?**

**a. If a utility overhead line is fully depreciated and upgrades or replacements are needed for distribution interconnection, does the DG customer pay for the upgrade replacement cost?**

HREA Response: In general, we would say no. This would be the case if the replacement or upgrade is needed to continue to serve existing customers, and if the DG customer provides distribution system benefits. However, it does not appear that this issue is covered under the utilities' Rule 14. H.

**b. Should a DG customer be required to pay for distribution system upgrades that would have otherwise occurred in the absence of a DG interconnection?**

HREA Response: No. The DG customer should receive a credit for helping the utility avoid the cost of a system upgrade. However, as above, it does not appear that this issue is covered under the utilities' Rule 14.H.

**c. Should subsequent DG customers on a particular feeder line be responsible for costs applied to the first DG customer on the line? If so, what type of crediting mechanism should be put in place for the first customer?**

HREA Response: HREA believes the utilities' Rule 13s generally addresses this issue.

**d. What mechanism should be used for recovery of these costs (i.e., fixed vs. demand charges, marginal cost vs. average cost, etc...)**

HREA Response: HREA recommends an approach whereby existing customers would not have to bear rate increases as a result of expanded service, unless of course their load expands. HREA supports recovery of these costs, where deemed appropriate, with a one-time connection charge (including generation, transmission, and distribution costs) to the DG facility owner/user.

**PUC-IR-21 Should HECO's, HELCO's and MECO's Rule 14.H on interconnection specific to distributed generation be modified to further facilitate or encourage distributed generation? If so, please identify with specificity those aspects of Rule 14.H that must be changed? Should the same interconnection rules for distributed generation apply to both the HECO companies and KIUC?**

HREA Response: HREA supports (see page 7, lines 23 and 24 of our PSOP) "interconnection and operational requirements that are fair and equitable to all parties." Furthermore, we support interconnection rules and agreements that have been developed in a voluntary consensus process, as indicated in our PSOP (page 13, lines 5 to 7). Rule 14.H was not developed in a voluntary consensus process.

In addition, based on a limited review of HECO's, HELCO's and MECO's Rule 14H, we believe there are a number of key issues that were not addressed and which we would anticipate addressing in a future voluntary consensus process. These include, but are not limited to:

(1) Specification of standard "standby charge" and/or a standard methodology to calculate project-specific standby charges;

(2) An approach to handling distribution system upgrade or replacement charges or credits to a DG customer;

(3) A power purchase agreement clause as an option for the DG customer wishes to sell wholesale power to the utility;

(4) Specification of what type and details of interconnection studies (if any) would be required in the case the DG customer wishes to sell

wholesale power to the utility. This would include a set cost and/or a methodology for determining the cost to the DG customer; and

(5) Clarification of the utility's requirement that CHP facilities not island.

Finally, from an industry perspective, it would be desirable if one set of standard interconnection requirements and rules were developed for and applicable to all of our island grids. However, at this moment, HREA is not sure this would be possible.

**PUC-IR-22 What has been the experience of the parties to date with interconnecting distributed generation facilities under either HECO's, HELCO's or MECO's Rule 14.H?**

HREA Response: HREA is aware that customers/CHP developers have had difficulty securing interconnection agreements for DG facilities in the past. This has also been observed by the COM (see COM-RT-1, at pages 12-14). While there may be claims that all previous issues have been resolved with the development of Rule 14.H, we are concerned how some of the issues identified above in our response to PUC-IR-21 will be resolved. Thus, we reiterate our recommendation that the existing Rule 14.H be revised via a voluntary consensus process.

In addition, HREA supports expedited treatment of applications for interconnection agreement applications. Specifically, we recommend that the PUC consider establishing a standard review/approval period, e.g., sixty days from submittal of a complete interconnection application to approval by the utility. After that, the utility would be subject to a financial penalty.

**Rate Structure and Cost Recovery**

**PUC-IR-23 Is the current allocation of distribution charges between customer, demand and usage charges adequate or should it be modified to accommodate DG? What is the appropriate allocation between utilities and ratepayers of revenues foregone as a result of the deployment of DG?**

**Rate Structure and Cost Recovery**

**PUC-IR-23** **Is the current allocation of distribution charges between customer, demand and usage charges adequate or should it be modified to accommodate DG? What is the appropriate allocation between utilities and ratepayers of revenues foregone as a result of the deployment of DG?**

HREA Response: HREA believes fixed costs should not be recovered through the energy charge. With appropriate rate design and customer/developer investment in DG facilities, there should be no revenues forgone as the result of deployment of DG. If the deployment of DG results in a reduction in sales by the utility, the utility should bear that risk until the next rate case, just as the utility enjoys the benefit of sales in excess of those used to design rates in the last rate case.

**PUC-IR-24** **Should credits be offered to customers or third parties that can defer the need for localized distribution expenditures. If yes, how should these credits be awarded, calculated and administered? And how should the cost of any credits or incentives be allocated and recovered by the distribution company?**

HREA Response: HREA supports offering credits to customers or third parties that can defer the need for localized distribution expenditures, but only to the extent of utility savings. Ideally, the utility should identify in their IRP specific distribution circuits or transmission planning areas where capacity additions will be required within a five year period, and specific rebates that would be offered, as was recommended in our PSOP (page 7, line 20). HREA recommended further (see our PSOP, page 14, lines 1 to 14), the preparation and execution of a DG implementation plan in IRP. Given the above, the costs of any credits or incentives could be allocated and recovered by the distribution company under its IRP program.

**PUC-IR-25 How can services be identified for unbundling and how should rates be calculated? Please comment on the viability of the Consumer Advocate's proposal for unbundling (Consumer Advocate Testimony, Witness Herz at 60-63). Will unbundling rates ensure that the utility recovers its cost of service from the customer benefiting from DG and does not shift costs to other ratepayers? (<u>See</u>, <u>e.g.</u>, Witness Herz, testimony at 23, 60)**

HREA Response: It is not clear to HREA that unbundling rates will provide for relevant cost recovery. As proposed by the CA, HREA understands that the costs that are recovered in rates are embedded costs, while the costs that are avoided through DG investment are marginal costs. As pointed out in the COM's RT-2 testimony by Mr. Lazar, in many cases the differences between these are huge. Specifically, Mr. Lazar's points out that the average embedded generation cost on the MECO system is under $1,000/kW, while the average cost of new generation is $3,000/kW. Clearly, the whole concept of unbundling and impacts on rates, including standby charges, needs further discussion.

In any case, HREA believes would be useful to unbundle and value ancillary services to the extent that the increased use of renewables creates a need for more reactive energy on certain circuits, so that the utility or others can sell/deliver the VARs needed to accommodate increased deliveries of renewable sources.

**PUC-IR-26 Should the commission consider decoupling revenues from sales so that the utility is indifferent to installation of DG that has the effect of reducing sales?**

HREA Response: Yes, this could be an approach to consider if the return to true class cost of service ratemaking, elimination of cross-subsidies, and removal of fixed costs from the energy charge, as advocated in our response to PUC-IR-23, does not produce desired utility behavior.

**PUC-IR-27** **Should the electric utilities institute termination charges (exit fees) for customers who install distributed generation and if so how should they be designed?**

HREA Response: No. On the other hand, given the current load growth profiles on HECO's system, perhaps customers that decide to exit the grid should be given a credit for load reduction.

**PUC-IR-28** **Should standby rates similar to those implemented by HELCO (<u>see</u> Decision and Order No. 18575, filed on June 1, 2001, in Docket 99-0207) be adopted by HECO or MECO? Is the flat fee standby charge used by KIUC an appropriate approach for other utilities? Or should the Commission repeal and prohibit standby charges?**

HREA Response: No. HREA recommends that the Commission adopt reasonable standby rates based on the costs for each electric utility to serve, and taking into consideration the capacity that DG can provide to the system at no cost to the utility and its ratepayers. In addition, HREA recommends that the Commission articulate a standby rate policy or methodology to ensure fairness.

**PUC-IR-29** **Please provide comments on the issues below related to standby service proposals.**

**a.** **To the extent that standby rates are implemented (for those utilities that do not have them) or modified, should demand subscription or non-firm standby rates be included? Please comment on the viability and desirability of a non-firm or "best efforts" standby service (<u>see</u> <u>e.g.</u> County of Maui testimony, Witness Lazar at 78)**

HREA Response: Yes, HREA supports the availability of more options, including the non-firm or "best efforts" standby service advocated by the COM (reference COM-RT-2, page 78).

**b.** **Should regulated utilities be required to charge themselves or their affiliates the same standby charges with respect to the regulated utility or affiliate owned, operated and maintained distributed generation facilities?**

HREA Response: HREA fails to understand why a regulated utility should "charge itself" a standby charge, given that a utility-owned CHP would, in effect, become part of the utility's generation. However, a utility should charge its separately capitalized, separately staffed affiliate the same standby charge that would apply to a nonaffiliated user of its services.

**c. Should standby rates be the same for all Hawaii electric utilities including KIUC?**

HREA Response: Given the different size and characteristics of each of our island grids, HREA doesn't believe it would be possible to design a "one-size-fits-all" standby rate. However, it should be possible to design a standard methodology for calculating island-specific and location-specific standby rates.

**d. Should supplemental service be distinguished from stand-by service and if so, should supplemental service continue to be charged at the otherwise applicable tariff?**

HREA Response: Yes, HREA supports distinguishing supplemental from standby service. DG customers, that are able to coordinate routine maintenance service with the utility, should receive a discount from the standby rate.

**PUC-IR-30 Please describe the electric utilities' current policies regarding "hook up fees" or impact fees. Should existing policies regarding hook up fees be revised so as to remove barriers to development of distributed generation? Please comment on the County of Maui's proposal regarding impact fees. (see discussion County of Maui Testimony; e.g., Kobayashi at 12; Lazar at 18-19, 33)**

HREA Response: HREA understands that each of the utilities has a current distribution hook-up fee that recovers the difference between marginal distribution costs and embedded distribution rates from new customers. COM's proposal for generation impact fees appears as an extension of this existing policy. However, the utility currently opposes "hook up fees" or "impact fees," which would recover costs for new generation.

**PUC-IR-31** **Should a systems benefit charge be adopted to recover costs of distributed generation? If yes, how should such a charge be established?**

HREA Response: System benefit charges ("SBCs") are adopted where there is a public benefit, e.g., some states employ SBCs to pay for RPS and/or DSM programs. Given that DG will provide public benefits and the PUC approves the use of utility incentives to DG customers installing DG equipment, these incentives are similar to and/or could become part of a DSM program under IRP. Thus, rather than setting up a new SBC, HREA recommends that these incentives be funded from the IRP surcharge, which really is a SBC.

**PUC-IR-32** **Will an inverted block rate design (see e.g. County of Maui, Witness Kobayashi at 12, Lazar at 86) result in better allocation of costs of new DG facilities? What are other benefits of inverted block rate design (if any) with respect to promoting DG?**

HREA Response: HREA believes an inverted rate design is most relevant to residential customers. Specifically, an inverted rate design will encourage energy conservation (e.g., solar water heaters), energy-efficiency and electrical generators, such as residential photovoltaics.

**PUC-IR-33** **How should costs associated with distributed generation be recovered?**

**a.** **How should the costs of fuel purchased for utility owned, customer site (sic) DG facilities be handled? Should it be included in the energy rate (sic) adjustment clause applicable to all customers or recovered in some other manner?**

HREA Response: HREA opposes utility ownership of customer-sited DG. Thus, we also oppose recovery of the fuel costs in the Energy Cost Adjustment Clause ("ECAC"). Rather than including the recovery of fuel costs in the ECAC, the DG customer should bear all fuel costs.

**b. Should regulated utilities be permitted to include in their regulated rates the cost of distributed generation equipment and its maintenance?**

HREA Response: HREA opposes rate-basing of utility-owned, customer-sited DG. However, there are elements of other DG equipment and maintenance costs that the regulated utilities should be permitted to include in their regulated rates. These elements include costs associated with integrating existing emergency generators into a virtual power plant and costs associated with utility DG systems serving public uses, such as the diesel units at the Hana substation on Maui. However, since utility DG systems, such as substation DG, become part of the utility, they should be treated the same as all utility generation.

**Integrated Resource Plan Process**

**PUC-IR-34 How should the existing IRP process and the deployment of DG be synchronized to maximize the benefits of DG?**

HREA Response: Per our response to PUC-IR-18, HREA supports the planning for and deployment of DG in the IRP process. HREA believes the deployment of DG can be best synchronized and expedited through utility DSM programs.

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**END OF HREA'S RESPONSE TO IRs FROM THE PUC**

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DATED: November 22, 2004, Honolulu, Hawaii

[signature]

President, HREA

## CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing "Prehearing Conference Statement and Response to the PUC IRs" upon the following parties by causing a copy hereof to be hand-delivered or mailed, postage prepaid, and properly addressed the number of copies noted below to each such party:

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Dated: November 22, 2004

President, HREA