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2004 JUN 16 P 3:18
PUBLIC UTILITIES COMMISSION

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

---- In the Matter of ----	)	
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PUBLIC UTILITIES COMMISSION	)	DOCKET NO. 03-0371
	)	
Instituting a Proceeding to Investigate Distributed Generation in Hawaii	)	
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RESPONSE OF HAWAII RENEWABLE ENERGY ALLIANCE

TO

INFORMATION REQUESTS FROM VARIOUS PARTIES

ON

HREA'S PRELIMINARY STATEMENT OF POSITION

AND

CERTIFICATE OF SERVICE

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The Hawaii Renewable Energy Alliance (HREA) hereby submits our response to Information Requests (IRs) from various Parties on our Preliminary Statement of Position (dated May 7, 2004), to the Public Utilities Commission (PUC), in accordance with the PUC's Prehearing Order Number 20922 (Reference Docket No. 03-0371).

I. INTRODUCTION

HREA received IRs from the following Parties: A. the Consumer Advocate (pages 3 to 23), B. HECO (pages 23 to 35), C. Hess-Microgen (page 35), D. The Gas Company (pages 35 to 44), E. Johnson Controls, Inc. (page 44), and F. Life of the Land (pages 44 to 48). HREA's response, prepared by its President (Warren S. Bollmeier II), is included in the following six sub-sections.

Please note that the IR format, including numbering system, is as received from the individual Parties. Also note that HREA's response to the Parties includes references to WSB-Hawaii's study, entitled "Study of Renewables and Unconventional Energy in Hawaii, which was prepared for the Hawaii Energy Policy Forum. The study can be reviewed and/or downloaded at the following web-site location: http://hawaiienergypolicy.hawaii.edu/papers/bollmeier.pdf

A. THE CONSUMER ADVOCATE

CA-SOP-IR-49 Ref: HREA SOP, page 6, lines 7- 9

a. **Please identify the specific sites where the near-term DG projects can be installed on each island and the anticipated capacity of each system from each technology identified as being possible in the "near-term."**

HREA Response: This is an interesting and important, but challenging question. HREA will respond by discussing the sites by the type of DG as HREA has defined DG. Specifically:

i) Demand-Side [customer-side of the meter, including traditional DSM, CHP and renewables, such as solar hot water (SHW), solar air conditioning (SAC), sea water air conditioning (SWAC), wind, PV, biomass, and hydro]. There are literally thousands of traditional DSM options (including SHW for homes, private businesses and government buildings, etc. Most of these would be relatively easy to permit, and it is not practical to identify specific sites with a few exceptions. Most of these exceptions do not have permits and some would more difficult to permit, e.g., projects on government land. A brief discussion of the DG market from HREA's perspective is provided by island as follows.

Oahu. On HECO's IRP, the DSM committee has identified a potential of 100 MW of DSM projected from now to 2009. The 100 MWs includes conservation (e.g., solar hot water) and traditional energy-efficiency measures. There is a proposed 75 MW SWAC/central district cooling project for the Kakaako area, which is not included as part of the 75 MWs. Note: HECO has not quantified the potential for renewables and CHP to the same level of detail. HREA believes that there is a market potential of at least 50 MW of CHP market potential between now and 2009 in hotels/resorts and government/military applications. Referencing WSB-Hawaii's study for the Hawaii Energy Policy Forum study, there is a potential for 1 MW of net-metered PV on residences and small businesses by 2008.

Maui. At the present time, HREA does not have an estimate for traditional DSM measures and CHP on Maui (including Molokai and Lanai), and notes, perhaps, that MECO could provide estimates. Referencing WSB-Hawaii's study for the Hawaii Energy Policy Forum study, there is a potential for 3,000 additional SHW systems and 150 kW of additional net-metered PV, wind, biomass and hydro.

Hawaii. At the present time, HREA does not have an estimate for traditional DSM measures and CHP on Hawaii, and notes, perhaps, that HELCO could provide estimates. Referencing WSB-Hawaii's study for the Hawaii Energy Policy Forum study, there is a potential for 3,000 additional SHW systems and additional 150 kW of residential net-metered renewables.

Kauai. At the present time, HREA does not have an estimate for traditional DSM measures and CHP on Kauai, and notes, perhaps, that KIUC could provide estimates. Referencing WSB-Hawaii's study for the Hawaii Energy Policy Forum study; there is a potential for 100 kW of net-metered renewables.

ii) Supply-Side (utility-side of the meter, including renewables and CHP). At the present time, HREA does not have an estimate for supply-side CHP systems, and notes, perhaps, that HECO, MECO, HELCO, and KIUC could provide estimates. Referencing WSB-Hawaii's study for the

Hawaii Energy Policy Forum study, the potential in MW for nine wind and biomass supply-side renewable projects is indicated in the table below, which is excerpted from the WSB-Hawaii study:

Technology	**Oahu**	**Maui**	**Hawaii**	**Kauai**	**Totals**
Windfarms	50	20	30	10	110
Biomass	10	15	8	9	42
Totals (in MW)	60	35	38	19	142

Notes: The project locations are: Oahu (wind at Kahuku and biomass at HPOWER), Maui [wind at Kaheawa Pastures and biomass – To Be Determined (TBD)], Hawaii (wind at Hawi – 10 MW and South Point – 20 MW, and biomass – TBD), Kauai (wind and biomass – TBD). Permits are needed at all these projects, with the exception of permits that are approved or pending at Kaheawa Pastures, Hawi and South Point.

b. **Please explain what efforts have been taken to ensure that the necessary permits to install the units can be obtained.**

HREA Response: On the demand-side, permitting will be primarily to obtain a construction permit. On the supply-side, project developers take the responsibility for obtaining permits for the individual projects. Referencing the WSB-Hawaii study, the nine projects were selected as realistic, based in part on the ability for developers to obtain the necessary permits. For CHP. In addition to construction permits, an air permit would be required for CHPs that use liquid fuels or gaseous fuels for CHPs over 1 MW. Overall, HREA believes the permitting process for DG can and should require less time and expense than for CG.

c. **Are the possible projects anticipated to serve only a specific customer(s)?**

HREA Response: Clearly, virtually all of the DSM projects would serve specific customers, e.g., traditional DSM measures, SHW, net-metered renewables, SWAC, and demand-side CHP. The remainder of the projects, as currently envisioned, would not serve specific customers.

1. **If yes, please identify the customer(s) who will be served by the units.**

HREA Response: HREA cannot identify specific customers at this time.

2. **Does HREA envision the customer(s) entire load to be served by the DG project, or only part of the customer(s)' load with the utility serving the remaining load. Explain.**

HREA Response: HREA believes this question is best answered by potential customers. However, in most cases, we believe the initial market will consist of customers seeking to off-set only a portion of their load, e.g., SHW, net-metered renewables and also CHP. As the confidence grows in the specific technologies and they become more cost-effective, either due to drop in system costs and/or increases in utility rates, we believe more customers will seek to become zero-net energy users, i.e., the home or building requires no net energy from the utility.

3. **If no, will the energy produced by the DG facility be connected to the utility's transmission and distribution system to serve the utility's customers?**

HREA Response: HREA believes initially virtually all customers will want to remain interconnected to the grid. There are at least three reasons for this: first, the customer may want to be net-metered, second, the customer may want back-up power from the utility, and, third, the customer may wish to sell any excess DG power to the utility. As customers shift to becoming zero net energy users, they will most like seek to disconnect from the utility and/or become net-metered. The latter option will most likely be preferred, from a system standpoint, as the net-metered systems will help support the grid.

4. **If yes, will transmission and distribution system upgrades be required to inter-connect the DG project to the utility system?**

HREA Response: HREA can think of only one situation where that might be necessary. That would occur if it was deemed desirable to install a large amount of DG on a specific distribution line in order to support that line or the overall grid.

5. **If yes, what efforts have been taken to ensure that the necessary permits can be obtained to construct the additional transmission and distribution system?**

HREA Response: HREA cannot answer this question at this time. Perhaps, HECO, MECO, HELCO and KIUC could?

CA-SOP-IR-50 <u>Ref: HREA SOP, page 7, issue 2, line 3</u>

a. **Please explain to what "all barriers to the market" refers and identify each perceived barrier.**

HREA Response: The barriers to the market for DG providers include, but are not limited to, the following:

1. Transaction costs, such as cost of establishing a new business or new business office in Hawaii, and participation in applicable PUC dockets. This may be more of a barrier to a company that is establishing a new presence in Hawaii, as opposed to a company that is already here and is moving into the DG market. While these transactions are generally recognized as a cost of doing business, there are ways that to help business buy down these costs. For example, government could provide office space at discount prices, and offer a tax holiday for a number of years.
2. Buyers may be uncertain about new Sellers. This is especially true for DG providers that approaching potential DG users that have had a long term relationship with an incumbent REC. HREA suggests two possible remedies. In both, the REC would not participate directly in the DG market. In the first option, the REC would facilitate the DG market as part of their DSM activity (in this case, the SHW program serves as a good model). In the second option, the REC would "spin off" an unregulated DG company, which would then compete directly with other DG providers (in this case, Provision serves as a good model, as it is a DG provider).
3. Access to affordable financing. This is another cost of doing business that all companies must bear. It is more of a barrier if the playing field is not level. For example, a REC has access to lower cost financing, which is a potentially

significant advantage. The remedies are the same as for item 2 above.

4. Uncertainty of performance in a new market. This is another cost of doing business that all companies must bear. It is more of a barrier if the playing field is not level. For example, the REC may have "deeper pockets" than other DG providers. The remedies are the same as for item 2 above.

5. Difficulty in reaching potential DG users, especially builders and renters. This is another cost of doing business that all companies must bear. It is more of a barrier if the playing field is not level. For example, a REC has intimate knowledge of its customers, and other DG providers will be at a significant disadvantage. Ultimately, they will be able to reach potential DG customers, but at a much greater expense than for the REC. The remedies are the same as for item 2 above.

6. Time and expense required to obtain a sales or use agreement (such as a lease or easement) with a DG user. This is another cost of doing business that all companies must bear. It is more of a barrier if the playing field is not level. For example, a REC may have "deeper pockets" than independent DG providers. The remedies are the same as for item 2 above.

7. Potential hidden costs, such as meeting utility interconnection requirements. This has already proven to be a barrier on projects such as Pohai Nani in Kaneohe on Oahu. The remedy is to develop and implement standardized

interconnection requirements and agreements for all DG technologies. We support development of standardized interconnection agreements and agreements via a collaborative process, which includes the REC, the PUC and all other interested Parties.

8. Time and expense required to negotiate and obtain interconnection agreements and/or power purchase agreements. It is well-recognized that windfarm developers have labored 5 or more years in negotiations with HECO, HELCO and MECO on power purchase agreements. The costs of protracted negotiations can kill projects. The remedy is to develop (in a collaborative process as discussed in item 7 above) and implement (with PUC approval) standardized interconnection requirements and agreements and standard offer power purchase agreements for all DG technologies, and

9. Permitting costs, especially for projects on government or military lands. Since there are many DG opportunities on government and military lands or properties, the permitting costs will remain a barrier. One possible remedy would be to establish a government/military task force to investigate ways to streamline the permitting process for projects on government/military lands or properties.

b. **Explain why HREA contends that each item listed in response to part a. above is perceived to be a barrier to the market.**

HREA Response: Is included in response to question a. above.

c. **List the specific actions that must be taken to remove each identified barrier.**

HREA Response: Is included in response to question a. above.

CA-SOP-IR-51 <u>Ref : HREA SOP, page 7, issue 2, lines 8 through 13</u>

a. **Please elaborate on HREA's vision of the "DG Market." In your discussion, please include sufficient details on how the market would operate.**

HREA Response: HREA thanks the CA for this important and thought-provoking question. HREA can envision two desirable DG market futures.

1. <u>Structured Competition</u>. In this market, the REC would facilitate the implementation of DG as part of the REC's DSM and SSM activities as follows: (a) planning – in IRP, the REC would identify the amounts and location of desired DG. The REC would also develop the desired DG specifications, including standardized interconnection requirements and agreements via a collaborative process as described previously herein. This information would be released, in advance of need (when possible), to DG providers; (b) implementation – the REC (with approval by the PUC) would pre-qualify DG providers for competitive bidding on DG RFPs, the RECs would issue DG RFPs to both DG providers and potential DG users, and select and forward winning proposals to the PUC for approval. The REC would inspect all approved installations to ensure compliance with the system specifications and interconnection requirements. Note: the requirements would likely include provisions for coordination

between the DG owner/operator and the REC on operation of the DG facility. Also note: structured competition will provide the following **benefits to the utility, DG user, ratepayers and the DG industry** as follows. The **utility** would benefit from: (a) obtaining the DG in the amounts and locations desired and avoiding complications that would arise if too much DG were developed in the wrong area (s), (b) increased system reliability at a low (or no) cost to the utility, (c) increased options to meet its RPS, and (d) potentially, an appropriate profit for its facilitation of the DG market. The **DG user** would benefit from: (a) increased choice to meet his electricity and/or electricity savings needs, (b) increased reliability and quality of the power to meet his loads, (c) options to reduce emissions by utilizing waste heat, and (d) lower electricity rates; **ratepayers** would benefit from non-utility investments in DG projects. Specifically, the non-utility investments will help mitigate potential rate increases, especially in times of load growth. The **DG industry** will benefit from: (a) less front-end costs to identify market opportunities, (b) predictable costs for meeting system specifications and interconnection requirements and agreements, and (c) the opportunity to compete on a level playing field for specific projects

2. <u>REC Participation via an independent, utility-derivative, unregulated entity</u>. This option would be basically the same as the structured competition, but with one important

difference. The REC would be allowed spin off an unregulated entity that could be qualified as DG provider. This DG provider would then compete with all other DG providers for specific projects in response to RFPs from the REC.

b. **Please identify the specific steps, beyond erecting appropriate firewalls that would need to be taken to implement and maintain HREA's vision of the DG market.**

HREA Response: HREA believes that the steps, based on HREA's response in item a. above would be:

1. Modifications to IRP – e.g., analysis and planning for DG in DSM and SSM applications will need to be more detailed in order for the REC to: (a) identify the desired locations and amounts of DG, and (b)prepare DG specifications as an input to the implementation process.
2. Creation of Special DSM and SSM programs – e.g., to implement the DG options identified in item b.1 above.
3. Examination of the need for program incentives – e.g., for what DG technologies would rebates be appropriate, and what would an appropriate profit incentive for the REC?

c. **What are the "appropriate firewalls" and explain how they would ensure a level playing field.**

HREA Response: HREA's response is in two parts as follows:

1. <u>Structured Competition</u>. In this case, there would be no need for firewalls, as the REC would be facilitating the DG market and would NOT be a direct participant, or participate via an unregulated, utility-derivative DG provider; and

2. <u>REC Participation via an unregulated, utility-derivative, DG provider ("utility-derivative DG provider")</u>. In this case, there would be a need for firewalls and enforceable requirements that: (a) no REC employee, Officer or Director is also an employee, Officer or Director in the utility-derivative DG provider that would be "spun off" from the REC, (b) the utility-derivative DG provider has a totally independent office and facilities and share, in no way, any office materials, supplies, furniture, equipment, web sites, etc., with the REC, (c) the utility-derivative DG provider is not provided any data or information that is NOT provided to all of the other DG providers, and (d) no funds are transferred from the REC to the utility-derivative DG provider, including start-up, engineering and commissioning costs.

d. **HREA states "[t]he un-regulated utility entity would then compete with our energy service providers." Please identify to whom "our energy service providers" refers.**

HREA Response: HREA apologizes for a typo. The word "our" should have been "other."

CA-SOP-IR-52 **<u>Ref: HREA SOP, page 7, issue 3, lines 17 through 21</u>**

a. **Please explain how the current rebate programs referred to would work to support the envisioned DG market.**

HREA Response: There are existing rebates that support traditional DSM activities, including the SHW program. HREA is suggesting that the need/desirability for rebates be evaluated for each DG technology.

Ideally, rebates could be used to encourage DG implementation and also to level the field among the competing DG technologies.

b. **If there were a rebate, please explain how the rebate would allow the utility and other owners to be competitive with each other.**

HREA Response: The primary purposes of the rebates would be to stimulate customer interest in specific DG technologies, and, possibly (as mentioned above) to level the field among the DG technologies. With respect to competition among the "utility and other owners" does not apply, as HREA does NOT support the direct competition of the utility (REC) in the DG market, and specifically, does not support the REC's owning and rate-basing DG equipment, fuel costs and other O&M costs. Finally, as noted in our response to CA-SOP-IR-51, HREA has indicated how a utility-derivative DG provider could compete with other DG providers.

c. **Who would be responsible for paying the costs of the rebate offered in the DG market?**

HREA Response: HREA believes it is appropriate for the ratepayer to pay the costs of the rebates, as they already are in the REC's DSM programs.

d. **HREA states "DG energy service providers have access to the market". Please explain to what "the Market" refers.**

HREA Response: The market is the business activity consisting of Sellers (DG providers) soliciting and providing their products and services to Buyers (DG customers). The market also includes the structure of the arrangements between the Buyer and Seller, and who owns/operates the

DG facilities. For example, the Buyer (DG customers) could purchase and then own and operate their DG facilities, or the DG customer could contract to lease the DG facilities from the DG provider and then operate the facilities themselves, or the DG customer could contract with the DG provider for specific products (e.g., electricity, hot water, etc.) and services (e.g., operations and maintenance of the DG facilities).

CA-SOP-IR-53 **<u>Ref: HREA SOP, page 7, issue line 22</u>.**

Please provide copies of the administrative rules that would need to be implemented.

HREA Response: HREA does not have any specific recommendations to present at this time, but reserves the right to provide recommendations at a later date.

CA-SOP-IR-54 **<u>Ref: HREA SOP, page 8, issue 4</u>**

a. **Will DG owners be compelled to operate the DG projects in order to provide reliability to the electric utility system; or will the DG facilities be operated based <u>solely</u> on the savings or profits to the customer who is served by the DG facility or the owner of the facility? Explain.**

HREA Response: HREA thanks the CA for this interesting and important question. HREA believes the DG owner/operator should have the option to choose the mode of operation he wishes to operate his DG facility. HREA cannot imagine a case where a DG project should be compelled to operate in a specific manner, unless required in a mutually-agreed-upon interconnection agreement. This question does suggest some opportunities whereby the utility and the DG owner/operator could both win. These include:

1. The DG owner/operator agrees to provide power at specified times, e.g., during peak hours, and/or be dispatchable by the REC. If so, it may be appropriate for the DG owner/operator to be compensated for these ancillary services, or, as an alternative, be relieved of any stand-by charges for back-up power or other services from the utility; and
2. The DG owner/operator agrees to provide other ancillary services, such as power at specific times to support the line voltage on the grid, or shut-down at night to allow the grid to run more efficiently. Similarly, it may be appropriate for the DG owner/operator to be compensated for these ancillary services, or, as an alternative, relieved of any stand-by charges for back-up power or other services from the utility

b. **Please identify the specific situation(s) in which HREA has determined that DG can be used to avoid distribution system upgrades to a new hotel or resort?**

HREA Response: HREA has not identified in situations where DG could be used to avoid distribution system upgrades to a new hotel or resort. HREA has not conducted, and does not plan to do, a study of the distribution system on any of Hawaii's island grids. Furthermore, such studies should be conducted by the REC's as part of their IRP.

c. **In each of these situations, who is expected to pay for the DG project? Explain.**

HREA Response: HREA thanks the CA for this interesting and important question. Based on HREA's vision of the DG market, HREA sees the following ownership options:

1. <u>The DG customer pays for and owns the project</u>. In this case, the DG customer could elect to operate the project or contract for O&M services; and

2. <u>The DG customer leases the DG project facility from a DG provider</u>, in which case, the DG provider (or possibly a financial institution) would pay for and own the project. In this case, the DG provider would most likely also operate the facility and charge the DG customer for the electricity, hot water, etc. provided by the DG facility.

d. **Please elaborate on what is meant by "the innovative and competitive manner that DG would be implemented."**

HREA Response: HREA believes there are plenty of examples where innovation and competition have benefited customers and industry, e.g., telecommunications. Specifically, benefits accrued through restructuring of the telecommunications industry and market. Ironically, one of the key issues before this docket is whether to increase competition in Hawaii's electric utility market by structuring the DG market to provide and encourage competition. Clearly, HREA supports that approach.

Restructuring in the telecommunications market resulted in innovations, such as new options for telephone equipment and services. HREA would also like to note that those innovations did not come initially from the incumbent monopoly. They came from independent companies seeking to win market share by providing customers with increased choices and an alternate rate structure for telephone services. HREA believes that it can NOT be disputed that the customer has benefited across the board in terms of value for desired services.

Consequently, HREA sees a similar set of benefits if a competitive market structure is created and implemented for DG. As described herein, HREA has illustrated two examples of how the market might be structured (See HREA's response to CA-SOP-IR51).

CA-SOP-IR-55 <u>Ref: HREA SOP, page 10, issue 5, lines 3 through 8.</u>

a. **Please provide specific examples of non-fossil-fueled DG projects that have achieved greater system availability than fossil-fueled generators and that can be dispatched for reliability purposes when called upon within 10-15 minutes notice.**

HREA Response: HREA thanks the CA for this interesting and important, albeit leading, question. HREA considers this to be a leading question because the issue of system availability, reliability and dispatchability are three different concepts, whereas it appears to HREA that the CA is emphasizing and placing value on dispatchability.

First, a number of DG technologies have high system availabilities, where system availability is defined as ratio of the hours in a year that a system is available to run (uptime) vs. the number of hours that the system is not available (downtime), e.g., for routine maintenance or repairs. DG technologies that have demonstrated high system availabilities are wind turbines, PV, SHW, pumped-storage, and hydropower systems. HREA also believes that most CHP systems will have high system availabilities, but that remains to be demonstrated.

Second, "reliability purposes" needs to be defined in the context of this question. HREA assumes that the CA is implying reliability of the utility system, and specifically, the ability of the utility to meet customer load. The addition of DG to the utility system will increase reliability and

HREA believes this can be measured in terms of a reduction in the loss of load probability and/or loss of load hours per year.

Third, "dispatchability" refers to the ability for the utility-system operator to "turn on/off" a generator or to increase/decrease the power level of an operating generator to meet increasing/deceasing load demand. Generally, meeting increasing load demand is more difficult. Clearly, conventional fossil fuel generators (assuming they have adequate fuel) can be turned on and off by command of the system operator. However, not all fossil fuel generators can be turned on within a 10 to 15 minute period.

A more critical and desirable capability would be a generator that can respond instantly. Examples would be spinning conventional generators and biomass generators at less than full power output, and pumped-hydro and battery storage.

Now to respond directly to the CA's question, of the list indicated on page 10, landfill, geothermal and hydro have the potential of a higher system availability and also be dispatchable. It is possible that biomass-fired facilities, which are dispatchable, could match or exceed system availabilities of conventional fossil generators. Finally, renewable pumped-storage (charged primarily by renewable sources, e.g., wind at night) would have both higher system availability than conventional generators and would be dispatchable.

b. **If not already discussed in the response to part a. above, please identify any examples of non-fossil-fueled DG projects in Hawaii, or on other island systems, that have achieved greater system availability than fossil-fueled generators and**

that can be dispatched for reliability purposes when called upon in a 10 – 15 minute notice.

HREA Response: Example include: Wailuku River Hydro (Big Island), Puna Geothermal (Big Island) and HC&S Sugar Mill (Maui). Note: Wailuku River has been dispatched by HELCO, e.g., curtailed at night in times of low load and then dispatched in the morning

CA-SOP-IR-56 **<u>Ref: HREA SOP, page 10, issue 6, lines 19 through 26.</u>**

a. **What type of DG project is envisioned that will <u>permanently</u> avoid T&D upgrades? Please provide a detailed response that describes the applicable project and the applications by which the DG project would <u>permanently</u> avoid T&D upgrades.**

HREA Response: On issue 6, HREA discussed the deferring of T&D upgrades and avoiding the costs of such upgrades. It is not clear if T&D upgrades can be permanently avoided. It may be possible in areas where utility load growth peaks and not further growth occurs.

b. **What type of DG project would be dispatchable in a manner that can supply spinning reserves? Please provide a detailed response that describes the applicable project and applications by which the DG project could be dispatched in a manner to supplant the existing means of providing spinning reserve.**

HREA Response: On issue 6, HREA discussed the possibility that installation of DG can reduce spinning reserve requirements, in part due to the reduction of line losses. Specifically, if a DG supplies a local load, the amount of spinning reserve is reduced by the amount of the local load plus the amount of line loss in supplying that load. This would be true whether the DG operates at all times, such as fossil DG, or part of the time, such as wind and PV.

Fossil-fired CHP, biomass-fired, geothermal and renewable pumped-storage facilities would be example of DG projects that would be dispatchable in a manner that can supply spinning reserves. All of these could provide "operating spinning reserve," i.e., additional power if the units are operating at less than full output. Operating in synchronous-condense mode (interconnected and spinning, but providing no power output), pumped-storage, however, would be the only facility of this group that could provide up to its full power output within a matter of seconds to less than a minute from the time that it is dispatched.

CA-SOP-IR-57 <u>**Ref: HREA SOP, page 13, issue 10, lines 19 through 24.**</u>

a. **Please explain how the suggested tiered-rate system would be consistent with the utility's cost of service. Provide copies of all computations that support the response.**

HREA Response: HREA believes that the tiered-rate system could be designed to ensure recovery of the utility's cost of service. HREA has not conducted a detailed analysis to explain how the suggested tiered-rate system would be consistent with the utility's cost of service. HREA is suggesting that this type of approach be examined, including experience in other jurisdictions. See Exhibit A – Restructuring and Ratemaking: Implications for Distributed PV Applications, C. Herig and T. J. Starrs, ASES 2002 Conference Paper (after the end of the IR responses)

b. **Please explain why the customer charge currently authorized for each electric utility operating in the State would decrease if, in fact, customer charges collect fixed costs and not variable costs such as fuel?**

HREA Response: HREA does not have a detailed answer for this question at the present time. Perhaps the ratemaking structure could be based on the total amount of electricity sold and the amount of required revenues without separating costs in to fixed and variable charges?

CA-SOP-IR-58 <u>HREA SOP, Page 14, lines 2-3.</u>

a. **Please provide the values the each identified benefit and explain how the value would be used to facilitate DG implementation.**

HREA Response: HREA does not have an answer for this question at the present time.

b. **Please explain how each value provided in response to part a. of this information request was determined.**

HREA Response: HREA does not have an answer for this question at the present time.

B. HECO

HECO/HREA-IR-1 Ref: HREA Preliminary Statement of Position, pages 6-7

In order to facilitate the implementation of DG, isn't it appropriate for the regulated electric utility to be an active participant in the DG market? If the answer is no, please explain why not.

HREA Response: HREA's response is in the negative and is in two parts.

First, facilitation (facilitator) and participation (participant) are two different concepts. A facilitator is one that assists in a process and theoretically makes it easier, less contentious and more successful. A participant is one that is in the process, e.g., providing DG services to customers. HREA's position is that the regulated electric utility should be a facilitator and not a participant. The regulated electric utility should work with all energy services providers, e.g., identify DG market opportunities, solicit proposals for DG in specific areas, etc, as noted in our position as stated in Planning Issue #3 (page 7 of our SOP).

Second, designing and implementing an innovative and competitive market is one of the key issues of this docket. HREA believes an innovative and competitive market will provide the most benefits to customers, the utility, the DG industry and the state. We also believe for a competitive market, there must be at least five active participants (DG Service Providers), and no one of those participants can have a dominate share of the market, or a dominate segment of the market. See additional comments in response to HECO/HREA-IR-7.

HECO/HREA-IR-2 Ref: HREA Preliminary Statement of Position, pages 6-7

If DG and CHP systems are beneficial in helping to meet the State's energy goals (e.g., increased energy efficiency and a reduction in the use of fossil fuels), then why would it not be reasonable for a regulated electric utility to be an active owner/operator in the DG/CHP market?

HREA Response:

Note: HREA considers CHP to be a type of DG and, thus, HREA will only use the term CHP when it is appropriate, e.g., in discussing the performance of CHP technologies.

As a follow-up to HREA's response to HECO/HREA-IR-1, HREA can support the role of a regulated electric utility (REC) as a facilitator in the DG/CHP (DG) market, but not as a participant (active owner/operator).

<u>HECO/HREA-IR-3 Ref: HREA Preliminary Statement of Position, pages 7-8</u>

Does HREA believe that the Commission has the appropriate authority to oversee the regulated electric utilities' involvement in DG/CHP projects? If the answer is no, please explain why not.

HREA Response: We consider this to be a leading question, as it assumes that a REC should be a DG provider. However, if that were so approved, in theory, HREA believes the Commission has the appropriate authority to oversee the REC's direct participation in the DG market. In effect, DG projects are miniature power plants, which are already regulated by the Commission.

HECO/HREA-IR-4 Ref: HREA Preliminary Statement of Position, pages 2-3

a. Does HREA acknowledge that to date there has been only a limited number of DG/CHP projects implemented in the State of Hawaii?

HREA Response: Yes, CHP is an emerging energy technology group and there are a limited number of CHP projects in place in Hawaii. HREA's understands for example, there are on the order of 12 CHP and three dozen net-metered PV systems in place, while there are on the order of 80,000 solar hot water systems in Hawaii.

b. Does HREA acknowledge that the involvement of the regulated electric utility in the DG/CHP market should result in a larger potential market for DG/CHP installations?

HREA Response: We would agree that there would be larger potential market for DG installations, if the REC facilitated the DG market, such as being done in the solar hot water (SHW) market segment. However, it is not clear to us that there would be a larger number of DG installations if the REC was a participant, i.e., a DG provider in the emerging market segments, such as CHP. Initially, there might be a tendency for customers to stay loyal to their incumbent energy provider, i.e., their REC. However, time and again, it has been shown (e.g., telecommunications), customers will exercise their right to choose, if there is an opportunity to do so. HREA believes the competitive market will provide the largest potential market for DG, and that is one of reasons why we support creation of a DG market, where only non-REC companies are allowed to provide DG systems and services.

HECO/HREA-IR-5 Ref: HREA Preliminary Statement of Position, pages 6-7

Does HREA acknowledge that utility participation in the DG/CHP market on a regulated basis should lead to a larger market than the current status quo of only a limited number of DG/CHP projects being implemented in Hawaii?

HREA Response: Same answer as for (b) above.

HECO/HREA-IR-6 Ref: HREA Preliminary Statement of Position, pages 13-14

If the regulated utility should be allowed cost recovery for those costs associated with implementing DG under IRP, then why shouldn't the regulated electric utility also be allowed to own and operate DG/CHP systems?

HREA Response: We support cost recovery for HECO to facilitate DG under IRP, but oppose cost recovery for HECO as a REC to be a DG provider, i.e. own and/or operate DG systems. In short, cost recovery by a REC, such as HECO, will result in rate increases just as when T&D is upgraded and new generation constructed, owned and operated by HECO. Specifically, when the costs of construction, ownership and operation of DG are recovered from the rate payers by HECO, rates will go up.

As HREA believes and HREA believes is generally recognized by other Parties, the implementation of DG can provide a number of benefits to the utility and the ratepayer, including avoiding line losses, avoiding or deferring T&D upgrades, and deferring new generation requirements. Thus, if DG is provided by non-utility entities, and hence not rate-based, rate increases can be mitigated, if not, avoided. This is a particularly attractive benefit, which can show Hawaii the way to get off the ramp to perpetual rate increases.

HECO/HREA-IR-7 Ref: HREA Preliminary Statement of Position, page 7

a. Does HREA acknowledge that the Commission has the requisite authority to monitor the regulated electric utility involvement in the DG/CHP market such that it does not "exert its monopoly power and unfairly influence the marketplace"?

HREA Response: We consider this to be another leading question, as it assumes that a REC should be approved to be a DG provider. If that were so approved, in theory, HREA believes the Commission has the appropriate authority to oversee the REC's involvement in DG projects. In effect, DG projects are miniature power plants, which are already regulated by the Commission. However, we are not sure it would be possible for the Commission to ensure that the REC does not "exert its monopoly power and unfairly influence the marketplace."

b. Please explain what is meant by "exert its monopoly power".

HREA Response: HREA thanks HECO for asking this question, as it is at the heart of the issue of how DG should be implemented. HREA's response is in two parts.

Part 1. As the franchise monopoly utility, HECO generates or purchases, and then sells virtually all of the electricity on Oahu with on the order of $1B in sales annually. HECO owns and operates all utility infrastructure with the exception of three power plants (AES, Kalaeloa and HPOWER). HECO has developed a formidable public and government relations capability, including its consumer outreach, web-site and presence in the community, vendors and suppliers, and the legislature. HECO has intimate knowledge of key elements of understanding and developing the DG market, e.g., its customer's load and demand profiles, and the transmission and distribution system. HECO is developing an understanding of DG technologies and is researching DG-specific problems and issues. All of this represents monopoly power, and all is supported by the rates paid to HECO by its customers.

Part 2. By exerting its monopoly power, HREA means that HECO, HELCO and MECO could:

(1) withhold information about its customers and their electricity needs, and place a large burden on new companies seeking to enter the market,

(2) interpret interconnection requirements in a manner that would make compliance difficult and expensive for non-HECO companies,

(3) influence potential DG customers to steer away from other DG providers,

(4) influence the fuel selection for CHP in Hawaii, and

(5) offer customer retention discounts to influence customer decisions.

c. Please explain what is meant by "unfairly influence the marketplace".

HREA Response: As a follow-up to HREA's response to HECO/HREA-IR-7, the exertion of monopoly power would result in an unfair influence in the marketplace. Specifically, competition would be stifled, as it would be difficult and expensive for new DG providers to enter the market and difficult for those that enter the market to counter the REC's home-field advantage which is bolstered by the rate base.

HECO/HREA-IR-8 Ref: HREA Preliminary Statement of Position, page 10

Does HREA acknowledge that until the installation of DG/CHP systems increase and there is an adequate track record of these systems' performance, that it would be premature at this time to assert that DG/CHP can delay and/or replace T&D facilities?

HREA Response:

HECO states the following on page 16 of HECO's SOP: "In concept, DG can impact or defer the need for certain T&D facilities. T&D facilities (such as lines and transformers) may have to be upgraded in capacity or additional lines added to avoid overloads under contingency and projected peak conditions. If enough DG is added and reliability operated so that peak load growth is reduced, then the deferral benefit might be realized."

HREA would agree that a track record is needed to verify the deferral benefits, but there are precedents for suggesting a high level of confidence in the ability of certain DG, such as CHP, to provide these deferral benefits. First, there are operational data from existing CHP that can be analyzed, and, second, HECO has confirmed deferral benefits from the SHW segment.

HECO/HREA-IR-9 Ref: HREA Preliminary Statement of Position, page 14-15

Does HREA believe that it is prudent for the regulated electric utility to adopt a portfolio type approach to meeting the electric needs of its customers with a combination of DG/CHP resources, central station generation, renewables, demand-side management programs and conservation initiatives?

HREA Response: Yes, but HREA believes it is now prudent for the REC to facilitate an aggressive move towards DG, including renewables, DSM, conservation and CHP.

HECO/HREA-IR-10 Ref: HREA Preliminary Statement of Position, page 12

Please quantify in terms of barrels of LSFO and/or diesel fuel the significant potential for DG to reduce the use of fossil fuels.

HREA Response: HREA can provide its perspective on this question, but would like to defer to those Parties that can also provide expertise and input. Given that, HREA's preliminary response is in three parts, based on an assessment of the near-term market (now to 5 years from now).

Part 1 (Types of DG). As HREA has defined DG for the purpose of this docket, there are three basic components: (1) measures to preclude the need for electricity (conservation, including SHW), (2) measures to generate renewable energy, and (3) measures to use fossil-energy more efficiency (conventional energy-efficiency and CHP).

Part 2 (Capacity and Energy Contributions). As part of HECO's IRP (3rd Round), HECO has just presented a DSM forecast for 100 MW of capacity savings by 2009 from DSM measures that include conservation (e.g., solar hot water) and traditional energy-efficiency measures. HREA believes that forecast is achievable. However, HECO has not quantified the potential for CHP and renewables to the same level of detail. Nevertheless, HREA believes that CHP conservatively would save 50% of the fuel now required to meet a customer's load. So, assuming 50 MW of CHP market potential between now and 2009, that would result in 25 MW of conventional fuel saved. With respect to renewables, WSB-Hawaii estimated the near-term (2003 to 2008) potential for renewables on Oahu at almost (at 50 MW wind projects, 10 MW biomass and 1 MW of net-metered PV)

Part 3 (Barrels of LSFO and Diesel). If the amount of energy savings can be estimated, the number of barrels of diesel can be readily estimated assuming an average heat rate for HECO's generators, and some simplifying assumptions about the dispatch of those generators. In answering this question, HREA is assuming an average heat rate of 10 mmBtu/MWH for HECO's generators and 6 mmBtu per barrel of oil. Therefore, by 2009 the estimated total annual savings could be over 1.2 million barrels/yr as follows:

(1) DSM portion of 100 MW are estimated by HECO save 326 GWh/yr, which would save approximately 543,000 (543,333) barrels/year;

(2) renewables portion (50 MW of wind, 10 MW of biomass and 1 MW of net-metered PV), could save almost 400,000 (397,141) barrels a year; and

(3) CHP portion (50 MW capacity), could save 292,000 barrels/yr, assuming the energy efficiency portion of CHP is 50% and the average CHP system capacity factor is 50%.

HECO/HREA-IR-11 Ref: HREA Preliminary Statement of Position, page 9-10

Please explain in greater detail the positive impacts that DG/CHP will have on power quality and reliability.

HREA Response: The positive impacts of DG on power quality and reliability will, of course, depend on the specific type of DG. With respect to power quality, the power output from advanced wind turbines and PV will have less total harmonic distortion than power from the grid. The advanced wind turbines, such as the GE 1.5 MW will be able help stabilize the grid by providing VARS and supporting the line voltage. Similarly, CHP generators can help support line voltage and provide cleaner power.

With respect to reliability, the overall reliability of the grid is a combination of the reliability of the generators and the T&D system. The overall reliability of the generators is a function of the number of generators, the size of each generator, and the reliability of the individual generators. As a worse case, if HECO had one 2,000 MW generator, a high system reliability would be hard to achieve. Clearly, if the generator were down for maintenance, the load could not be supported, and there would be a relatively high system loss-of-load probability and loss-of-load hours. On the other hand, the existing system has a number of generators, and the system reliability, assuming the reliability of each generator is the same, is driven by the size of the largest generator. If it is down, the loss-of-load probability is higher. Thus, adding generators will increase the system reliability, and adding small units, such as DG, will further enhance system reliability.

Finally, adding DG will most likely improve the reliability of the T&D system, since the load on individual transmission and distribution lines will be lowered, and the lines will be operating at lower load factors and lower temperatures. Operation a lower load factors and lower temperatures should result in a lower number of failures.

HECO/HREA-IR-12 Ref: HREA Preliminary Statement of Position, page 6

Please define what you mean by the terms "feasible" and "viable".

HREA Response: Feasibility relates to the state of maturity of a specific DG technology, including its performance and costs characteristics, and whether it can operate satisfactorily in Hawaiian applications. This includes the ease and costs of integrating and interconnecting with our island grids. Viability relates to the economics to the DG provider and customer. In current economics (with or without incentives), can the DG provider sell equipment and services to the customer and make a reasonable profit, and will the DG customer be willing to pay the price for the equipment and services offered.

HECO/HREA-IR-13 Ref: HREA Preliminary Statement of Position, page 7

What detailed customer knowledge does the utility have that is not available from the customer?

HREA Response: The utility possesses the detailed records (from utility bills) of the amounts of capacity and energy purchased by its customers, and, in many cases, has established long-term working relationships with potential DG customers. It is possible that potential customers may have stockpiled their utility bills, but it is also possible they may not have more than a few months of records. In any case, it is clear that the utility has a head start in working with its customers and understanding their needs. This is the nature of the monopoly utility.

HECO/HREA-IR-14 Ref: HREA Preliminary Statement of Position, page 7

Please explain what you mean by the phrase "backing by the ratepayers".

HREA Response: "Backing by the ratepayers" in this case means that all of the utility's costs are born by the ratepayers. For example, the REC may have already investigated the feasibility of DG, especially CHP, at the expense of ratepayers, whereas independent DG companies must raise their own funds.

HECO/HREA-IR-15 Ref: HREA Preliminary Statement of Position, page 7

a. Does a project developer's financial strength matter in terms of mitigating risk to customers?

HREA Response: HREA thanks HECO for raising this important question, albeit a leading question. Specifically, HECO appears to imply that the financial strength of a project developer would be a pivotal factor in a customer's assessment of risk. HREA would agree that individual DG customers would likely evaluate the project developer's financial strength along with a number of other factors, such as the developer's experience on other similar projects, his overall experience, and, of course, costs and technical factors relating to the proposed DG project. In the final analysis, the customer is the one to make the determination of the benefits, costs and risks associated with a DG project proposal. That is yet another reason, why HREA believes the customer should have access to multiple bids for his project.

b. Should there be limits on financial strength of firms that participate in the DG market?

HREA Response: No.

c. Do other entities in the DG industry exist that have greater financial strength and backing than the electric utility?

HREA Response: Yes, for example, General Electric, Caterpillar, Siemens, Mitsubishi, and Kawasaki, to name a few.

HECO/HREA-IR-16 Ref: HREA Preliminary Statement of Position, page 7

How would you propose that any rebate for DG be funded?

HREA Response: If the preferred method of implementing DG was under a utility DSM program and it was agreed that rebates were appropriate, HREA would support funding of the rebates by the ratepayers.

<u>HECO/HREA-IR-17 Ref: HREA Preliminary Statement of Position, page 10</u>

What is the normal basis for determining the amount of spinning reserve required?

HREA Response: HREA thanks HECO for raising this very important question, and would like to note that while HECO has a spinning reserve policy, HELCO and MECO currently don't. Spinning reserve, including operational reserve and standby, is normally determined as the amount (in MW) of the largest utility generator. The rationale for this approach is that the utility would instantly have available the amount of capacity (in MW) in the case that the largest generator experienced an unplanned outage.

HECO/HREA-IR-18 Ref: HREA Preliminary Statement of Position, page 15

a. What would be the key elements of standard offer contracts for DG?

HREA Response: The short answer to this question is the elements that both the utility and a DG operator can agree on. Normally, the key elements are price (for purchase of electricity sold to the utility), term of the contract, and the interconnection requirements, which can be quite detailed.

b. What is the role of the utility in the contemplated transaction?

HREA Response: The role of the utility in the contemplated transaction is to work collaboratively with the DG industry and other interested policy to develop standard offer contracts.

HECO/HREA-IR-19 Ref: HREA Preliminary Statement of Position, pages 12-13

a. Does HREA believe that any specific sections of HECO's Commission approved Rule 14H need to be revised?

HREA Response: Yes.

b. For the specific sections listed in response to part a. above, please provide an explanation as to what needs to be revised and the benefit to the utility, other utility customers and/or the DG owner/operator of the proposed revision.

HREA Response: HREA will provide detailed comments on Rule 14H at a later time.

C. HESS-MICROGEN

HESS-SOP-IR-1 to HREA **Ref.: HREA's SOP p.16**

Please explain in more detail the proposed changes that you are proposing be made to the State Administrative Rules.

HREA Response: HREA Response: HREA does not have any specific recommendations to present at this time, but reserves the right to provide recommendations at a later date.

D. THE GAS COMPANY

TGC/HREA-SOP-IR-1 Ref: HREA Preliminary Statement of Position, p.7

a. If a rebate program were to be offered, who does HREA believe should receive the rebate, e.g., site-owner, electric customer, DG owner, etc.?

HREA Response: Rebates have generally been offered to the entity purchasing the energy system, typically the electric customer. However, HREA believes there should be some flexibility in terms of who receives the rebate, e.g., site-owner, electric customer, DG owner, DG provider, etc.

b. **Please explain what market barrier HREA believes a rebate program would overcome, given the current interest level in distributed generation installations.**

HREA Response: HREA supports the use of rebates to help accelerate the implementation of DG technologies as part of the REC's DSM and SSM activities. The rebates should be tailored to reduce the installed costs of specific DG technologies and, if possible, designed to level the field among the competing DG technologies.

c. **Does HREA believe that a regulated DG program can and/or should discriminate among similarly situated customers, given the generally compact island utility systems?**

HREA Response: HREA understands that "similarly situated customers" refers to customers with similar applications and loads, e.g., two or more commercial laundries, two or more hotels, etc. HREA believes the maximum benefit from DG can be achieved, if the REC's are required to revise their IRP process to identify the areas where DG is needed and then solicit in a competitive bidding process for DG project proposals. Given that, the similarly situated customers would not be discriminated against. On the contrary, assuming they were both located in desired DG areas; they would have the equal opportunity to bid on DG projects.

TGC/HREA-SOP-IR-2 **Ref: HREA Preliminary Statement of Position, p. 8, Impact Issue 4**

a. **Does HREA believe that all, none or some of the distributed generation facilities should be treated as a generation resource and factored into planning for generation reliability?**

HREA Response: HREA thanks TGC for this important question. As indicated above, HREA supports planning for DG in IRP. HREA believes that two important outputs of this planning process will be the: (1) amount of generation that could potentially be deferred (i.e., could be "all, none or some"), and (2) impacts on generation reliability.

b. **Does HREA believe that all, none or some of the distributed generation facilities should be treated as a load modifier, similar to DSM programs?**

HREA Response: In general, yes. As a follow-up to HREA's response to "a." above, HREA believes the answer to this question would be an output of a revised IRP process. HREA also notes that DG should be planned in both the DSM and SSM programs.

c. **Does HREA believe that an electric utility's planning criteria should be modified to include distributed generation?**

HREA Response: Yes

d. **Please explain if HREA believes that negative impacts to all energy utility ratepayers should be considered.**

HREA Response: HREA believes that impacts (positive and negative) to all energy utility ratepayers should be considered. This may not be as simple as determining the potential rate impact of specific projects. However, the impact of a 5-year DSM program, including CHP, and 5-year SSM program, including CHP, should provide the answer as to whether the impacts or positive or negative. Assuming that DG is planned in IRP and bid out competitively, and if generation and T&D benefits are captured , HREA believes the rate impacts will be either positive, or at the worse, neutral.

e. **Please explain if HREA believes that mitigating negative impacts to electric utility customers who are also gas utility customers is included in its position.**

HREA Response: HREA thanks TGC for raising this important question. HREA did not identify potential negative impacts to electric utility customers who are also gas utility customers in HREA's Preliminary SOP. However, it would seem logical that customers, seeking to reduce their energy bills, would benefit most from multiple choices, including both conventional technologies and new DG technologies for meeting hot water, cooking food, refrigeration and other energy needs. HREA believes that implementation of a competitive DG market would support that goal. HREA is interested in any situations that TGC believes would require mitigation.

TGC/HREA-SOP-IR-3 **Ref: HREA Preliminary Statement of Position, Section 6, p. 10**

Does HREA believe that all forms of distributed generation installations, including those that require supplemental and/or backup service from the electric utility, will offer the deferred and avoided costs listed or would the impacts differ? Please explain.

HREA Response: HREA believe all forms of DG will offer distributed benefits. The benefits (e.g., avoided utility costs) will differ with the DG technology. For example, some will offer generation deferral (e.g. CHP, geothermal, biomass, renewable pumped-storage), avoided T&D upgrades (e.g., CHP, PV, maybe wind), and spinning reserve costs (e.g., renewable pumped-storage, maybe biomass and geothermal, maybe wind and PV). Virtually all DG will avoid line losses and their associated costs.

TGC/HREA-SOP-IR-4 **Ref: HREA Preliminary Statement of Position, Section 9, p.12**

"We believe it is appropriate for the PUC to qualify or approve DG facilities for interconnection with the electric utility grid."

a. Does HREA believe that all DG facilities should require Commission approval, regardless of ownership?

HREA Response: HREA is happy to clarify its position on this important issue. Since it may be administrative cumbersome for the PUC, maybe there should be a capacity threshold (say 500 kW), below which a DG facility would not need to be qualified or approved by the PUC.

b. Does HREA believe that all DG facilities should be regulated?

HREA Response: No.

c. Please explain if HREA believes that Commission oversight should vary for the different forms of distributed generation, e.g., backup generation, those not designed or used to deliver power to the grid, those requesting utility backup service, etc.

HREA Response: As a follow-up to HREA's response to "a." above, there are important issues to be resolved in order to maximize the benefits of DG, not just to the DG owner, but also to DG providers, the utility and the ratepayers. Overall, regardless of the DG market structure (including what role the REC plays), HREA believes that PUC approval of standardized interconnection requirements and agreements, developed in a collaborative (voluntary consensus) manner, will serve as an important element of the PUC's oversight of DG. HREA believes that separate standardized agreements will be required for DGs that do not deliver power to the grid vs. those that do, and perhaps amendments to each of those to deal with issues related to back-up generation and utility back-up service, etc. Given these standardize agreements, the PUC's oversight during implementation might consist only of: (1) conducting a review of DG projects that are above a specific threshold, e.g., 500 kW as suggested previously, and (2) resolving complaints between DG providers or owners and the utility.

d. Please explain if HREA believes that standards other than technical standards (e.g., ownership) should be used to determine qualifying interconnections.

HREA Response: HREA thanks TGC for raising this important and interesting question. HREA believes there is a combination of technical and administrative standards that need to be developed in a collaborative (voluntary consensus) manner and approved by the PUC. These include: (1) interconnection requirements and agreements, (2) power purchase agreements, (3) pre-qualification of DG providers for competitive bidding on utility RFPs for DG projects, and (4) inspection of DG installations prior to operation.

e. Please explain if HREA intends these interconnection restrictions to apply to all types of DG installations, including those not designed or used to deliver power to the utility grid.

HREA Response: HREA supports the development and implementations of standards for all DG, including those not designed or used to deliver power to the utility grid. Specifically, while a DG might not be designed or used to deliver power to the utility grid, the utility might wish to require the DG to operate at certain times of the day and/or be dispatchable by the utility.

TGC/HREA-SOP-IR-5 **Ref: HREA Preliminary Statement of Position, p. 14 Cost Allocation Issues, Section 11, pp.14-15**

a. **Please explain if HREA is aware of the potential cost impacts of forms of DG on gas utility customers and the gas utility.**

HREA Response: Yes, HREA is aware of the potential cost impacts of forms of DG on gas utility customers and the gas utility. Adding to HREA's response to TGC/HREA-SOP-IR2, item "d," there may be rate impacts to gas utility customers, if other gas utility customers leave the gas utility system. If that happens, the gas utility (as well as the electric utility) will experience revenue losses.

However, if the Parties keep their eye focused on the overall energy goals of the state, all methods for reducing our use of fossil energy should be examined and implemented as appropriate. If substantial progress in made on the state's goals, there could be potentially significant impacts to the existing electric and gas utilities. For example, there could be less opportunity for the REC to invest directly in generation infrastructure and the REC could experience revenue losses, and the gas utility could lose a portion of its traditional water heating market segment, if CHP captured large traditional gas utility applications, e.g., laundries, hospitals, etc.

HREA would like to suggest that the utilities view this as a challenge and an opportunity.

b. **Please explain how HREA believes that the shifting of load between the gas utility and electric utility through distributed generation should be addressed.**

HREA Response: It is not clear to HREA that the load would be shifted from the gas utility to the electric utility. HREA believes that there will be an expanded market opportunity for the gaseous fuels in Hawaii to meet new DG. For example, with a shift to DG, HREA believes there will be an increased demand for propane, initially for reciprocating CHP and, then for fuel cell technologies as they enter the DG market. Depending on how the score is kept, the effective load ratio for the gaseous utility may actually increase. For example, if TGC supplies non-REC DG facilities, the effective result is to support electricity and heat recovery sales to the DG customers, while reducing traditional REC sales.

c. **Please explain how HREA believes that an optimal mix of DG measures should be determined and enforced.**

HREA Response: HREA thanks TGC for asking this important and challenging question. As HREA has defined DG for the purposes of this docket, emphasis should be placed on meeting demand first by energy conservation and traditional energy efficiency measures, then renewables and CHP, and, as a last resort, fossil CG (central generation). The basic logic is to NOT build more fossil CG when there are other cost-effective alternatives.

How to optimize? That is the multi-billon dollar question! HREA believes each REC should examine in thorough detail all DSM and SSM options. Each option should be compared on a bottom-line value, such as effective cost of delivered or saved electricity in cents/kWh. However, this effective cost should be examined not based on a surrogate cost, such as is now done in IRP, but based on the costs of delivering DG via a competitive bidding process.

Subsequently, options should be compared and ranked against each other in IRP for specified applications including alternatives to: (1) defer new generation, (2) provide/offset peak power, (3) provide/offset renewable requirements, and (4) other specific needs.

In any case, HREA believes it will be extremely difficult to obtain AN optimal mix without ACTUALLY increasing competition in the electric utility sector, and specifically competitive bidding for DG.

For example, if competitive bids are solicited for proposals to meet the specified applications, an optimal mix will be easier to achieve. Specifically, while IRP may suggest the most cost-effective and optimal DG measures, adjustments can be made based on the actual bidding process, i.e., some measures may come in lower than estimated or vice versa.

E. JOHNSON CONTROLS, INC.

JCI-IR-136 Please provide a complete copy of all data requests served by all other Parties and Participants to this proceeding on HREA and HREA's responses thereto.

HREA Response. All data requests and our responses thereto are included in HREA's response to the IRs from the various Parties herein.

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In any case, HREA believes it will be extremely difficult to obtain AN optimal mix without ACTUALLY increasing competition in the electric utility sector, and specifically competitive bidding for DG.

For example, if competitive bids are solicited for proposals to meet the specified applications, an optimal mix will be easier to achieve. Specifically, while IRP may suggest the most cost-effective and optimal DG measures, adjustments can be made based on the actual bidding process, i.e., some measures may come in lower than estimated or vice versa.

E. JOHNSON CONTROLS, INC.

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HREA Response. All data requests and our responses thereto are included in HREA's response to the IRs from the various Parties herein.

F. LIFE OF THE LAND

LOL-SOP-IR-35: What amount of backup and emergency generators currently exists in Hawaii?

HREA Response: HREA does not have a detailed estimate of the backup and emergency generators currently in Hawaii at the present time. Based on available anecdotal information, HREA believes that there is on the order of 100 MWs of backup and emergency generation on Oahu, at hotels, hospitals, pumping stations, military installations and other locations. Perhaps, either the Counties or the utilities could provide an answer to this question?

LOL-SOP-IR-36:

(a) What is a reasonable estimate (number of customers, MWh) for the CHP market on each island?

HREA Response: HREA does not have a quantitative estimate (number of customers, MWh) for the CHP market on each of the islands at the present time, i.e., HREA has not conducted a detailed market study. Qualitatively, HREA believes the initial CHP market will be focused on customers with large demand, such as hotels/resorts, government and military. Over time, however, CHP costs for residential applications will come down, and provide an opportunity for residences that are not able to achieve their energy goals with conservation, traditional energy efficiency and renewables.

(b) What is the maximum upper limit for CHP on each island?

HREA Response: HREA thanks LOL for this interesting and challenging question. If a far-term (20 to 30 years from now) view is considered, the potential for CHP could easily be 20% of the utility demand on each island, including both fossil and renewable CHP.

This goal will be influenced, in part, by the approach that customers pursue in meeting their energy needs. For example, assume that customers pursue a "zero net-energy building" goal. For many residential customers (about 30% of the demand on each of the islands), the goal could be met with conservation and energy-efficiency measures and net-metered renewables, i.e., not CHP. As noted previously, as CHP matures, CHP could fill in the gap left open for homes, condos and apartments that cannot utilize renewables.

Meanwhile, given that government, military, commercial and industrial customers make up the remainder (70%) of the demand on each of the islands, how many will pursue the net-energy building approach, and how feasible will CHP be? For HREA's purposes here, HREA is assuming that in the far-term, most of the existing CG will have been replaced with DG. Therefore, the maximum upper limit for CHP on each of the islands (again the far-term) could be as high as 70%, but would realistically be less for at least three reasons: (1) the state is seeking at least 20% in renewables by 2020 and perhaps 30% by 30 years from now. That would bring the maximum total potential of CHP to 40%; (2) some of the CHP will be renewable and may be counted as renewable, as opposed to CHP, and (3) it may not be realistic to capture more than half of the remaining 40% with CHP (i.e., 20%). For example, to maintain overall system integrity (while we still have island-wide grids), it may be necessary to have 20% or more of the system capacity under the utility system operator's direct control.

On the other hand, this capacity wouldn't necessarily need to be CG. It could be large DG, or perhaps as time goes on, the distinction will become blurred. In any case, achieving 20% of the load from CHP appears to be a reasonable goal.

LOL-SOP-IR-37: What percentage of the load can be offset by quantifiable energy conservation measures?

HREA Response: In order to answer this question, HREA needs to define "quantifiable energy conservation measures." In lieu of a ready source of a definition, e.g., the RPS bill just passed into law this year did not provide a definition, HREA proposes to define quantifiable energy conservation measures as those measures that: (1) off-set the need for electricity, (2) can be measured and verified by the utility, and (3) may be quantifiable, but do not pass the "stink" test.

Fortunately, there are some examples of quantifiable energy conservation measures already in place, but the list is fairly short. In fact, the only one HREA can think of is solar hot water (SHW) systems. All of the other present DSM programs are energy-efficiency, as opposed to conservation measures. The energy off-sets from SHW have been verified on the Companies' DSM program. There will be more examples, as other new renewable, energy-offset technologies mature, e.g., solar air conditioning (SAC) and sea water air conditioning (SWAC).

Some examples, that are not quantifiable energy conservation measures because they are either energy-efficiency or load management measures, include heat pumps, ice storage, and CHP.

Some examples of energy conservation measures that may be quantifiable, but fail to pass the "stink" test are: (1) hanging your clothes out to dry instead of using your electric clothes drier, (2) turning off your lights and sitting around in the dark at night, and (3) planning a new housing development to be an energy hog, then showing how you can save energy by cutting back on energy use.

So, what is the potential for quantifiable energy conservation measures? Referencing WSB-Hawaii's study, "Study of Renewables and Unconventional Energy in Hawaii, which was prepared for the Hawaii Energy Policy Forum, approximately 3% of the state-wide electric demand could be met by SHW alone by the year 2033. Similar projections for SAC and SWAC were not made or included in the study by WSB-Hawaii. Nevertheless, both SAC and SWAC have an excellent potential to contribute by reducing the air conditioning load in Hawaii's buildings. Based on available anecdotal information, there are about 300 MWs of air conditioning load on Oahu. HREA believes a significant portion of the air conditioning load could be met with a combination of SAC and SWAC.

END OF HREA'S RESPONSE TO IRs FROM THE VARIOUS PARTIES

DATED: June 16, 2004, Honolulu, Hawaii

President, HREA

RESTRUCTURING AND RATEMAKING: IMPLICATIONS FOR DISTRIBUTED PV APPLICATIONS

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ABSTRACT

The restructuring of the electricity industry is changing the way that electricity services are provided and priced. Electric utilities are facing the forced sale of their generation assets, the rise of retail competition, and the increasing viability of distributed generating technologies. Although these changes create new competitive opportunities as well as new competitive threats, the response among many utilities has been to propose new rate tariffs designed to preserve the utilities' existing revenue base. Some of the proposed rate structures will adversely affect solar energy markets by making it less economic for customers to reduce their reliance on utility power, either by conserving energy or by generating their own electricity.

This paper analyzes the implications for solar energy markets of some of the alternative rate structures that have been proposed by utilities, including:

- Switching the billing for transmission and distribution charges from usage-based (volumetric) charges to fixed charges, which increases the bills for low-usage customers and reduces the savings available for reducing electricity consumption through the use of on-site solar systems;
- Imposing so-called 'standby' or 'backup' charges on customer-sited generating facilities, including PV systems; and
- Requiring elaborate and expensive interconnection studies for customers who want to install their own generating facilities, even small-scale PV systems.

The paper will use actual examples of utility proposals that have been adopted to demonstrate the potential adverse effects of these new rate structures on solar energy markets. In addition, the paper will describe alternative ratemaking proposals that address the utilities' need to meet their revenue requirements in a way that does not discourage the development of customer-sited solar energy applications and other forms of distributed generation. The authors conclude that the choices made by policymakers in establishing new rate and tariff structures is likely to have a substantial impact on future markets for solar energy.

1. INTRODUCTION

Solar electric generation, or photovoltaics (PV) provide a modular, affordable distributed resource (DR) solution for both customer's needs and utility system capacity constraints. Consumers can invest small and add-on to a PV system. A PV system is easily integrated into a building's electric system, the building material envelope and the building's tie to the electric utility grid. However, this modular attribute becomes an economic detriment with proposed rate, tariff, and interconnection requirements designed for larger DR applications.

The utility industry has been in a transitioning mode for the past decade. Though state deregulation and restructuring activities did not occur until the mid-nineties, the impending threat had utilities minimizing operating, maintenance, and capital plant expenditures resulting in diminishing capacity margins for generation [1], transmission, and distribution. Couple in fossil fuel price volatility, and the fact that 95% of the nations generation capacity additions are for natural gas fired plants[2], and the resulting focus for the electric industry is towards distributed resources (DR).

Distributed resources, including both customer sited generation and efficiency technologies, offer electric utility generation, transmission, and distribution system relief. However, DR also presents operational and financial implications which utility system operators and regulators are not accustom to. The value attributes from the perspective of customer-sited DR differ immensely from established central generating plant operations. The solution to efficient system operation, both technically and economically, will require creative rate and tariff design combining the traditional utility system value with the consumer DR investment value attributes.

2. DISTRIBUTED PV – THE VALUE

Distributed PV application's small system size relative to other DR technologies offers a unique set of values to utility system operations.

- Residential and small commercial systems are typically sized equivalent or smaller to major building loads such as air conditioning, and refrigeration. Therefore, the distributed generation capacity availability or intermittency is also equivalent to load fluctuations routinely experienced by the utility system.
- Small system deployment results in minimum distribution feeder saturation and minimum distribution device coordination impact, providing DR experience at minimal risk, both in economics and operations.
- The generation resource and the utility system load driver are one in the same, the sun. Availability of PV was 90% or greater of ideal output for five of the six major recent power outages[3]. Availability for PV was also high during market price spikes reported by the New York independent system operator[4].
- The electronic interconnection through the inverter can be coordinated with the timing of the distribution protective devices.

Combine these small system and generation profile attributes with traditional DR attributes and distributed PV applications emerge as premium value DR.

3. PROPOSED TARIFFS AND INTERCONNECTION FEES

As DR technologies expand in the market place, utilities have proposed and implemented alternative tariffs, charges and fees. The purpose is to minimize risk financially by preserving revenue charges for existing plant capacity (revenue base) and operationally to the unknown effects of generation interconnected to the distribution feeder.
Both the financial and operational risks are dependant on the DR saturation[1] of the distribution feeder or set of distribution feeders out of a distribution substation. The definition of maximum allowable saturation of the distribution system is unknown. Most DR experience to date is with diesel generators in the size range of two megawatts, reflecting 20% saturation on a ten-megawatt feeder. The operational and financial risks could be substantial, with just cause for DR targeted tariffs, charges and fees. A 50 kilowatt distributed PV application, an average size commercial system or 10 large residential systems, represents 0.5% saturation on the same unit basis.

New tariffs with higher fixed charges, standby or back-up charges are justifiable for the purpose of investment recovery and operation and maintenance expenses for the distribution for large DR applications or multiple DR systems on a single feeder resulting in high saturation. Interconnection studies are also justified in high saturation DR conditions to assure distribution protective devices such as fuses, reclosers and sectionalizers are properly sized for any additional short circuit current. These applications, including large PV systems have potential economic and operational impact and a cost base high enough to minimize the impact of the alternative rate structure on the DR project. However, the more typical PV applications, with small size to building load ratio, generation/load profile match[2], and electronic interconnection present an opportunity for gradual transition to a more decentralized electric grid with minimal impact to both distribution operations and investment recovery. The impact of alternative rate charges and interconnection study fees is proportionately large enough on more typically sized PV systems and energy efficiency to discourage consumer investment.

3.1 Fixed vs Volumetric Charges in Tariffs

Electric tariffs have historically been based on usage or volumetric charges. The unit basis is either energy (kWh) or energy and demand (kW). Lower volume customers also incurred a fixed charge component in their rate, referred to as the customer charge. In a vertically integrated utility the price of generation, transmission and distribution is bundled into the usage charge and the fixed charges are priced to cover metering and billing, or the

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[1] Saturation is essentially a ratio of the DR generating capacity to the distribution feeder capacity. It may be expressed or calculated in units of energy or short circuit current.

[2] The generation/load profile match on a purely residential distribution feeder is offset relative to a feeder with a commercial and residential mix. However, recent analysis[5] has shown that interfacing a utility's direct customer load control operations distributed PV will compensate this offset while reducing the load control time interval for the same demand reduction.

fixed cost portion of service. With the major component of pricing based volumetrically, customer consumption is directly related to bill amount.

Electric utility restructuring activities have swept across the nation, resulting in utilities divesting generation assets and resulting in a focus on the distribution system. Pricing arguments have emerged to assert distribution costs are fixed system costs and should not be priced on a per unit basis. Investor owned utilities in Nevada filed rate design proposals to price the monthly customer charge large enough to recover 'fixed' distribution costs. The design proposal was approved by the Nevada Public Utility Commission in the spring of 2000. Southern California Edison also filed a proposal to increase the monthly customer charge from \$5 per month to \$17 per month. This fixed distribution charge pricing design dissuades customer's consumption decisions. The result is lower energy bill savings for customers investing in PV systems and efficiency.

The fixed charge component of electric service tariffs have typically been 5-10% of the average residential bill depending on the usage rate. Average fixed charges range between \$3-\$8 per meter month. The remaining 90%-95% of the bill is based on usage. The distribution portion of the kWh usage price component can be as much as 40%. Figure 1 shows that as the fixed charge is increased, high consumption customers are rewarded. The graph assumes a revenue neutral, base consumption of 700 kWh per year and an average bundled (generation transmission and distribution) rate of 10¢/kWh.

High demand periods have always been high cost periods for utilities even prior competitive transitioning. Generation is dispatched based on incremental expense. PV and many efficiency measures closely match and reduce electric grid system demand. Rather than reward demand responsive[3] behavior from customers such as investments in PV and efficiency, high fixed charge rate designs discourage consumer investments.

Figure 2 shows the decline in the annual bill savings as the fixed charge component increases. A 2 kW PV system could produce 3600 kWh per year with good solar resource. Or \$360 per year at 10¢/kWh, assuming all energy is either used by the building or the system is net metered. Consumption prior to installation of the PV system was assumed to be 700 kWh/mnth, with the same revenue neutral calculation for the fixed charge as Figure 1. A consumer's energy savings from investment in a PV system is also diminished by an increasing fixed price component in the tariff.

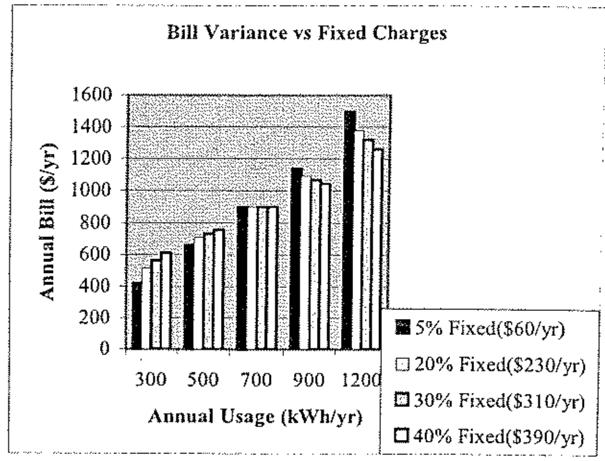

Fig. 1: Bill variance versus fixed charges

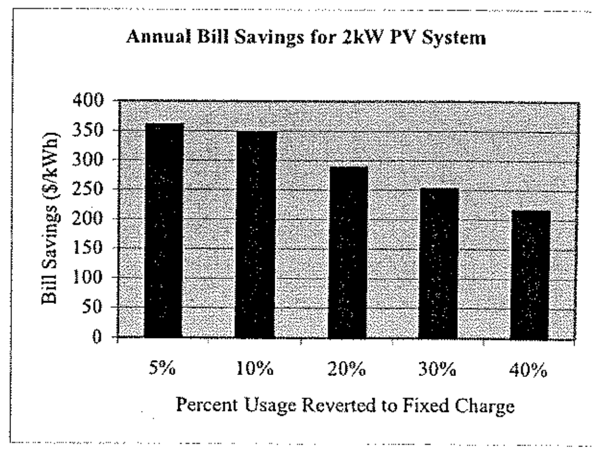

Fig. 2: Annual Bill Savings for 2kW PV System

3.2 Standby and Backup Charges

Standby or Back-up charges are imposed on self-generating customers to compensate the utility for reserve generating capacity required to serve the customer's load if the DR becomes unavailable. The conference report for the Public Utilities Regulatory Policy Act (PURPA) of 1978 suggested utilities may have set these charges at unreasonable levels purposefully to discourage self generation [5]. More recent accounts of standby charges show a range from a negative value or customer credit[4] to nearly \$200/ kW-yr [7]. PURPA required these charges to be reasonable, but were still intended for larger customer

[3] Reduction in energy will always represent some demand response, and PV output has shown to have a high system demand price match [4].

[4] Orange and Rockland compensates customer owned DR in capacity constrained areas.

generating facilities where the utility standby capacity is necessary.

Again, PV generates at levels smaller or equal to load fluctuations for which a utility is expected to have reserve capacity. DR Residential appliance and small commercial mechanical equipment on/off cycles are routinely accommodated by utilities. Additionally, if the PV generation/system load profile are closely matched, strategically distributed DR may actually reduce the required capacity reserve margin[8]. Previous analysis [9] on a proposed standby charge for net metered systems by Pacific Gas and Electric could add up to more than 100% of the PV system's monthly energy value depending on system size.

3.3 Interconnection Study Fees

Utility distribution systems are designed with protective devices such as fuses, reclosers, sectionalizers and breakers intended to protect all customers and isolate a minimum number of customers during fault conditions. These protective devices have historically been coordinated according to the short circuit current contribution from the centralized generator, available along the distribution feeder. Large DR facilities can add additional short circuit current requiring design changes in the size and timing coordination. Utilities have imposed interconnection studies (for which they charge a fee), utility grade protective device installation, and annual inspection fees for DR facilities. For large MW size DR facilities, a study is necessary for continued reliable operation of the distribution grid and reflected a proportionately small fraction of the DR facility cost. However, for PV systems less than 50 kW, case studies have shown interconnection costs[5] to range from a few dollars to $1,200/kW[7]. Included on the high end of these charges is a $1200 fee for a 0.9 kW system and a $400 fee for a 0.3 kW system.

4. ALTERNATIVE TARIFFS AND POLICY

A number of alternative tariffs and policies that encourage consumer investment in PV and restrict charges not applicable to small DR systems have emerged with restructuring activities and during the western energy crisis. Most of the alternative tariffs design is targeted towards consumer demand responsiveness. Next to conservation, energy efficiency and PV-DR are economically accessible[6] investments consumers can make to respond to energy pricing signals. Alternative tariffs include:

- Net metering, now available 35 states with varying rules on system size grid penetration, allows a customer to feed back excess PV-DR energy to the grid by reversing the electric meter. This results in full retail value for the PV energy since the customer pays the net of energy consumption less the excess PV energy fed to the distribution grid.
- Conceptually, real time by-directional pricing could capture the high value generating profile of PV-DR. Though not be-directional, real time pricing pilots are in progress at both Pudget Sound Electric and Gulf States Power. The Pudget Sound program uses the internet to transmit pricing signals. Gulf States communicates through a telephone line and specially designed in house signal device.
- Geographically differentiated pricing was piloted first in Loredo, TX. This pilot (concluded in 1995) included both geographic and time differentiated pricing for a distribution capacity constrained area. Additionally, Orange and Rockland, a utility with service territory in NY, NJ, and PA also encourages DR with incentives in areas with distribution capacity constraint.
- Tiered block pricing is a rate structure increasing the per unit charge for incremental tiers of usage. Analysis has shown this type of tariff design can be revenue neutral to the utility[10]. The investor owned utilities in California implemented this type of rate in the first quarter of 2002. The consumer response to this rate design along with mild weather are two major factors in averting the capacity shortfall expected in CA during the summer of 2002.

Policy implementing interconnection rules prohibiting utility requirements for fees, studies, insurance and additional equipment, for small DR systems have been implemented in both TX [11] and CA[12]. Similar rules have also been incorporated in state net metering policy. Additionally, there have been distribution interconnection rule proposals issued by the Federal Energy Regulatory Commission and within federal energy bills.

5. CONCLUSIONS

Distributed resources are a major contributor towards a more competitive electric market, a decentralized utility

[5] Some interconnection costs may include legal fees in addition to utility interconnection fees.

[6] Though PV is the most expensive renewable generator, its modular attribute allows consumers to invest in affordable increments even less than a kilowatt.

<u>CERTIFICATE OF SERVICE</u>

I hereby certify that I have this day served the foregoing Preliminary Statement of Position 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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