POST-HEARING ISSUES

By letter dated December 28, 2004, the Commission requested that all Parties and Participants respond to seven issues, in addition to those identified in Order No. 20832. The Commission requested that the additional issues be addressed in the post-hearing Opening Briefs. The responses of the HECO Companies to these additional issues are as follows.

A. WHETHER THE COSTS AND BENEFITS OF DISTRIBUTED GENERATION CHANGE IN TIMES OF EXCESS CAPACITY VS. TIMES OF SHORTAGES OF CAPACITY; IF THE ANSWER IS YES, THEN GIVEN THAT FOR THE LIFE OF ANY LONG-TERM ASSET THERE ARE LIKELY TO BE PERIODS OF EXCESS CAPACITY AND SHORTAGES, PLEASE COMMENT ON THE TIME SPAN OVER WHICH ONE SHOULD MEASURE THE COSTS AND BENEFITS OF DISTRIBUTED GENERATION.

If a resource (whether it is a distributed generation resource, an IPP generating unit resource, or a demand-side resource) is added when the utility has more than enough capacity to meet its capacity planning criteria[36], then it is not deemed to have any capacity benefit at that time. It can, however, have a capacity deferral benefit, in that the resource (alone or in combination with other firm resources) could defer the time at which additional capacity would have to be added to meet the capacity planning criteria. This capacity deferral benefit, which is calculated on a discounted present value basis to take into account how far in advance (of the date when deferred capacity would have been added) the resource causing the deferral is added. The calculation is done using the differential revenue requirements ("DRR") method to take into account all avoided cost benefits.

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36 The generation planning criteria are used to determine the amount of capacity necessary to serve projected customer loads, taking into account the need to have a large enough reserve margin to allow for scheduled overhaul outages, planned maintenance outages and unplanned forced outages of generating units.

This analysis has to take into account the life-cycle of the resource being added (and can be extended to take into account "end effects"). This is one reason the HECO Companies proposed 20-year CHP Agreements - - to provide assurance that the offset value of CHP systems to central station generation would remain in place long enough to warrant deferring central station generation. HECO has assumed that customer-owned and third-party owned CHP systems also will remain in place for 20 years, so that they can be given equivalent capacity deferral value in analyzing the value of a utility CHP program. (In reality, at least some customer-owned or third-party systems will be removed well before the end of 20 years, either because cheaper systems are installed, or because the systems may not be maintained as well as utility-owned systems.)

If the resource is added when the utility already has less capacity than the amount needed to meet its capacity planning criteria (i.e., when the utility is in a "reserve capacity shortfall" situation, such as is currently the case with HECO), then the resource has an immediate capacity benefit. The benefit is harder to quantify since the resource is not deferring the addition of more capacity, but is helping to make up for a shortfall. HECO used the proxy method to try to measure this value in its application (filed November 5, 2004 in Docket 04-0320) requesting approval of two amendments to its power purchase agreement with Kalaeloa Partners, L.P.

The costs of DG do not depend on the capacity situation of the utility. The costs are simply the costs to purchase and install systems, and to operate and maintain the systems.

1. Definition of Excess Capacity and Shortage of Capacity

First, it must be established at what point capacity, whether generation, transmission or distribution, can be considered "excess." The amount of capacity can be considered exactly "sufficient" at the point where the total capacity on the system is just enough to meet the capacity planning criteria. However, capacity over and above this "sufficient amount" is not necessarily "excess capacity." There must be enough capacity to accommodate expected load growth such that the there will no capacity planning criteria violations within the time it takes to install the next increment of capacity.

For example, suppose a system currently has a peak demand of 80 MW and total capacity on the system is 130 MW. Suppose also that currently only 110 MW are needed to exactly satisfy the system's capacity planning criteria but that new capacity cannot be installed on the system until five years from now (2010). Suppose further that over this period peak demand will grow at 4 MW per year so that in 2010, peak demand will be 100 MW and 130 MW will be just sufficient to satisfy the capacity planning criteria. The difference between the 130 MW currently on the system and the 110 MW needed to satisfy the planning criteria today is not necessarily "excess" capacity. That capacity is necessary to satisfy increasing demand during the period that new capacity is in the process of being installed. Therefore, while there may appear to be an excess of capacity in the near term, there is no excess over the long term.

On the other hand, if in this example new capacity could be installed sooner than 2010, then there may be "excess" capacity with respect to satisfying the capacity planning criteria, but consideration would need to be given to uncertainties such as the rate of load growth and the future peak reduction impacts of DSM and load management programs before concluding the capacity is in excess.

There is a similar definitional problem with respect to a "shortage of capacity." If a particular system's capacity planning criteria can be satisfied today but not necessarily over subsequent years because new capacity cannot be installed soon enough, then it could be argued that there is no shortage of capacity today but there will be a shortage later. However, if the planning criteria could not be met today, then there is clearly a shortage.

2. Costs and Benefits of Distributed Generation

The costs and benefits of DG depend on the nature of the DG being considered. For example, renewable DG such as small-scale wind or photovoltaics have the benefit of no emissions. These renewable DGs tend to have higher capital costs compared to conventional fossil-fueled DG units such as diesel engines.

The benefits of DG in terms of avoided central-station capacity, avoided central-station energy and avoided transmission and distribution capacity are thoroughly discussed in the direct testimony of Mr. Sakuda in HECO T-3, pages 1 to 7, and in the direct testimony of Ms. Ishikawa in HECO T-4, pages 18 to 25. The amount of the benefits depend on a number of factors, including but not limited to, the island upon which the DG is being installed since the amount of capacity deferral will depend on the capacity planning criteria being used (since each island has its own planning criteria); the extent to which new capacity is needed; the time it will take to install new capacity; the length of time the DG will be on the system based on the reasonably expected service life or on contracts with the utility; the size of the DG units; and the extent to which there is diversity of DG units on the electrical circuits.

3. Dependence of DG Costs and Benefits upon Excess or Shortage of Capacity

The benefits of DG can change in times of excess generation, transmission and distribution capacity and in times of shortages of generation, transmission and distribution capacity.

In times of "excess" capacity, the benefits of DG in terms of avoided costs will be zero or at least lower than if there is no excess capacity. This is because the DG capacity have little or no effect on deferring the next increment of central-station generating capacity or transmission or distribution capacity. The benefits of small-scale wind DG resources may be reduced if there is an excess of baseload capacity on the system and the output of the wind units must be curtailed during low load periods.

When there is a shortage of capacity on a system, the benefits of DG in terms of avoided costs will likely be higher than it would otherwise be if there were no shortage. This is because they would be satisfying an immediate need.

4. Time Span Over Which Costs And Benefits Of DG Should Be Measured

Given that over the life of any long-term asset there are likely to be periods of excess capacity and shortages, the time span over which the costs and benefits of DG is measured needs to be carefully considered. In essence, the planning horizon over which the costs and benefits of DG are measured needs to take into account the life cycle costs of the DG being installed. For example, if the expected service life of a DG unit is 10 years, then the period of analysis for avoided costs should encompass the entire 10-year period of the DG's service life. If multiple DGs are being installed at different times and it is impractical to extend the planning horizon to the end of the life of the last DG, then steps must be taken to account for "end-effects." End effects are a means to calculate the difference in costs between two plans that have different resource addition patterns by assuming the resource addition patterns will repeat in perpetuity such that the differences in capacity and reliability across the two plans become equalized over the long term.

B. HOW SHOULD NON-UTILITY OWNED DISTRIBUTED GENERATION BE INCORPORATED INTO THE IRP PROCESS, IN A MANNER COMPARABLE TO THE TREATMENT OF UTILITY OWNED DISTRIBUTED GENERATION, SO THAT THERE IS NO MARKET OR REGULATORY ADVANTAGE OF ONE TYPE OVER THE OTHER?

The IRP process does not result in or create market or regulatory advantages for utility-owned CHP over non-utility owned DG. The IRP process determines whether DG/CHP as resource in meeting customer energy needs should be pursued when compared with other resource options, and whether the utility-ownership option is cost-effective.

IRP, by its nature, analyzes resources at the system level prior to identification of specific projects. Additionally, individual DG projects are generally too small to impact the timing of central station generation or transmission line additions. For these reasons, DG must first be considered on a generic basis and the site-specific impacts a particular project may have on the system are not considered. HECO T-1 at 36.

The HECO Companies have focused their analysis of DG in IRP on CHP because the Companies foresee a substantial customer demand for this technology. To this extent, the estimated market potential could affect the Companies' resource decisions. See HECO T-1 at 2.

From an IRP perspective, two primary questions must be addressed. First, what impact could CHP have on the need for resources on the utility's system? Second, should the utility undertake CHP as a resource option?

The HECO Companies plan to perform two separate evaluations of CHP in the HECO IRP-3 process, which is currently in progress. The first evaluation will be performed as part of the main integration effort, where long-term resource plans are developed from combinations of demand-side and supply-side resources. The plans will consider two levels of CHP market sizes: (1) the Companies' best estimate of the CHP market level and (2) a high or optimistic CHP market level. The analysis will be performed independent of ownership. The market sizes will take into account the total of non-utility and utility CHP. The integration analysis will determine the impact of each market size on the selection and timing of demand-side and supply-side resources for each finalist resource plan. In order to simplify this analysis, CHP costs (capital, O&M, or fuel) and CHP revenue impacts in the calculation of total resource costs for each of the finalist resource plans will not be included. Instead, the first analysis will focus on how different CHP market sizes affects the timing and types of resources selected for the candidate resource plans. HECO T-3 at 13.

The second evaluation the HECO Companies plan to perform is a supplemental analysis to demonstrate the impacts of CHP ownership (utility versus non-utility) on total resource costs and utility revenue requirements. This second evaluation will focus on the impact to ratepayers resulting from CHP resources as a function of CHP ownership. This evaluation will be limited to impacts to one resource plan – the utility's preferred resource plan. Impacts of CHP ownership will be made by performing calculations of total resource cost with and without utility participation in the CHP market, including the estimated cost for capital, O&M, and fuel for a Utility CHP Program. In addition, this supplemental analysis will also consider any changes in utility revenue due to discounts to electric rate tariffs, facilities charges, and thermal charges. HECO T-3 at 13.

In addition, within the IRP process, the impact of DG/CHP on the transmission system may be given limited consideration (in a few finalist plans). System-level forecasts of DG/CHP can be allocated down to the transmission substation level to identify the potential impact of DG/CHP on the timing and location of transmission planning criteria violations. HECO RT-4 at 7. It is not practical to consider DG/CHP impacts in the IRP process with respect to distribution planning. The distribution planning process involves smaller geographic areas compared to transmission planning. Since customers make the decisions as to what facilities will be built, and when they will build facilities, the demand forecasts for these small geographical areas cannot be made further than three to five years into the future and can fluctuate substantially. HECO RT-4 at 9.

C. WHETHER TRANSMISSION AND DISTRIBUTION COSTS WILL BE SUBSTANTIALLY REDUCED FOR CHP OR OTHER DISTRIBUTED GENERATION PROJECTS SET UP FOR PEAK SHAVING ONLY

The foregoing question can be construed to ask whether transmission and distribution system costs will be substantially reduced or whether transmission and distribution interconnection costs for peak shaving DG/CHP projects will be substantially reduced. The HECO Companies will respond to both questions. It should be noted, however, that it is not economic to install CHP systems for peak shaving purposes only, although other DG might be used for this purpose. CHP systems generally are sized based on the customer's thermal requirements, and are operated so as to be able to provide the waste heat necessary to meet the customer's thermal requirements. Thus, the customers peak electricity requirements generally will be served by the utility grid. (However, base loaded CHP systems will reduce the amount of customer load that central station generation generally has to serve, as discussed in the Opening Brief. Moreover, the possibility of oversizing the generation component of the CHP systems for the purpose of peak shaving was raised during the panel hearings. The consensus was that this would be more feasible in the case of utility-owned CHP systems.

First, the HECO Companies will respond to the question of whether new transmission and distribution projects can be deferred either for the long-term (20 year or more period) or for the short-term (several years), and whether such deferrals can substantially reduce expenditures on new transmission and distribution projects (such as upgrades) when CHP and other DG projects are installed and implemented as peak shavers only.

The ability to defer long-term and short-term transmission projects will depend on the specific situation being evaluated and should be studied on a case-by-case basis. Some of the factors involved with evaluation of DG on the distribution system were included on page 19 of the HECO Companies' Preliminary Statement of Position ("PSOP") which include 1) the configuration of the distribution system (radial versus network), 2) length of distribution lines, penetration of distributed generation on the primary circuit and the back up circuit, reliability and redundancy of customer systems, synchronous or induction generation, grounding of transformers and other equipment and short circuit characteristics of the distribution circuit. HECO T-4, pages 13-17 explains some of the issues with relying on DG to defer (either in the long-term or short-term) transmission and distribution upgrades. In addition, transmission and distribution upgrades can only be deferred if they are caused by increases in load demand compared to the need for upgrades due to the installation of new generating resources. See HECO RT-4 at 12-13 (for a more thorough explanation).

As an example, hypothetically DG resources with sufficient diversity installed at a substation feeding a distribution radial line could theoretically defer the need to upgrade a distribution line. Several factors (assuming that sufficient number of units are installed to provide back-up when a unit is down for maintenance or on a forced outage) should be considered in determining if DG could defer the distribution upgrades. If the DG units are operated coincident with the peak of the line, there could be some deferral. If the DG units are operated during the system peak which does not coincide with the peak load demand of the distribution line, then the distribution upgrade cannot be deferred because the distribution line will need to serve the peak load demand of the line. In addition, the duration of the peak load demand is an important factor to consider. DG units installed for peak shaving may have run hour restrictions which limit the operation of the unit to a certain amount of run hours. The peak load demand on the radial distribution line may have peak periods which last 5 hours per day, 7 days a week. The DG units installed for peak shaving will be required to operate coincident with the peak load demand of the radial line in order to defer an upgrade of the distribution line.

Also in this scenario, it is assumed that the DG is serving load demand on a radial line the DG unit is installed at the beginning of a radial line where the generation from the DG unit will flow through the radial line to feed the local load demand. If the DG unit is connected to a network system, the flow of energy from the DG unit could flow in different directions depending on the load demand conditions. Numerous load flow cases will need to be simulated to review all possible line configurations in a network system to determine where the energy from the DG unit will flow in order to determine if a distribution upgrade can be deferred.

Second, the HECO Companies will respond to the question of whether transmission and/or distribution interconnection costs can be substantially reduced for CHP or other distribution generation ("DG") projects that are implemented as peak shavers only.

The impacts of DG operated as a peak shaver, will still require an evaluation of the interconnection requirements under Rule 14.H. Interconnection costs will vary depending on the size and location of the DG unit and are typically not dependent on how the unit is operated. See HECO Companies' Response to PUC-IR-20 (for an example where a DG facility may need to install a grounding scheme, isolation devices, interrupting devices and a dedicated step-up transformer). Facilities such as these may still be required because even if the DG is operated for peak shaving, protection systems for the DG interconnection will be required regardless of the manner in which the unit is operated.

D. WHETHER POTENTIAL LOSS OF REVENUES TO INVESTOR-OWNED UTILITIES, DUE TO ADVANCEMENTS IN TECHNOLOGY AND THE DEVELOPMENT OF NEW MARKETS IS A RISK FOR WHICH THE UTILITY HAS BEEN AND IS COMPENSATED THROUGH ITS APPROVED RATE OF RETURN; AND WHICH FORMS OF DISTRIBUTED GENERATION, IF ANY, WOULD FALL INTO THE CATEGORY OF ADVANCEMENT RISKS FOR WHICH THE UTILITY ALREADY RECEIVES COMPENSATION

The ratemaking process determines a utility's revenue requirements and sets prices that will yield a specified annual return on the value of property used and useful in public service – the rate base – plus collect for necessary and proper operating expenses, taxes, and depreciation. If advancements in technology or the development of new markets caused a major customer to leave the utility system, then there could be a shortfall in the utility's recovery of operating expenses and/or there could be stranded costs – the decline in value of utility assets. The utility would not be adequately compensated through its approved rate of return.

If the rate base remains the same, then the approved rate of return multiplied by the utility's rate base will produce the same allowed return as before the customer left the system. However, the utility is not being adequately compensated for its fixed costs of operating and maintaining the rate base, due to the lost revenues from the departing customer. To remedy this situation, the utility would need to go through a new ratemaking process to reallocate the fixed costs across its remaining ratepayers, and rates would need to be increased.

With regard to stranded costs, these costs have typically been considered within the context of electric industry deregulation, where deregulation has been applied to generating assets but not distribution assets. The bulk of stranded costs in this context arise from unrecoverable costs of generation assets, uneconomical long-term contracts for power or fuel, and unrecoverable regulatory assets such as deferred income tax liabilities. Deregulation technically has not taken place in Hawaii, however, advancements in DG technology or the development of new customer DG markets could produce similar stranded cost impacts if they were to proceed to a point where significant amounts of customer-sited non-utility DG were developed. In the case of DG, these stranded costs would arise from both generation and distribution assets, since DG could allow a certain amount of bypass of the utility distribution system. <u>See</u> HECO Companies' Response to Question 5.

Based on the above, there are no forms of DG which fall into the category of advancement risks for which the utility already receives compensation.

<u>Setting The Rate Of Return On Common Equity</u>

The fair rate of return on common equity must satisfy the three requirements for fairness established by the <u>Bluefield</u> and <u>Hope</u> cases. The requirements for "fairness," as set forth in Bluefield Water Works & Improvements Co. v. Public Service Commission of West Virginia (262 U.S. 679, 1923) and in Federal Power Commission v. Hope Natural Gas Company (320 U.S. 391, 1944), are that the return should:

(1) Be commensurate with returns on investments in other enterprises having corresponding risks and uncertainties;

(2) Provide a return sufficient to cover the capital costs of the business, including service on the debt and dividends on the stock; and

(3) Provide a return sufficient to assure confidence in the financial integrity of the enterprise so as to maintain its credit and capital-attracting ability.

These criteria have been used by the Commission in numerous HECO rate case decisions including Decision and Order ("D&O") No. 14412 (Docket No. 7766, HECO 1995 Test Year), D&O No. 13762 (Docket No. 7700, HECO 1994 Test Year), and D&O No. 11699 (Docket No.

6998, HECO 1992 Test Year) as well as numerous Hawaii Electric Light Company, Inc. ("HELCO") and Maui Electric Company, Limited ("MECO") rate case decisions.

This fair rate of return generally has been ascertained by using the discounted cash flow ("DCF") model and various equity risk premium models (such as the "CAPM") to ascertain the market-required return for comparable electric utilities (with some adjustment for risk differences not captured by the comparability tests). Some of the models use current and projected results for the comparable companies, while others (such as certain equity risk premium models) rely heavily on long periods of historical results.

Historically, utilities have not had to sell their product in competitive markets. There was very little risk of losing revenues due to technological developments and development of new markets (by which the HECO Companies assume the Commission is referring to product markets that can displace the need for utility system supplied power). When new technologies have provided a more cost-effective alternative than continuing to operate an existing facility, the utility generally has been allowed to include the cost of the new facility in rates, and to retire the old facility without reducing rate base (or to amortize the cost of the abandoned facility if rate base is reduced). Thus, the rate of return did not have to compensate the utility for this "risk".

The electric utility market is becoming increasingly competitive, however. Investors are less certain that utilities will be allowed to recover the costs of prudently made investments, because of market conditions, or because of the unwillingness of regulators to recognize the "regulatory compact" under which such investments were made. (The Hawaii Commission has recognized such a regulatory compact.) As a result, regulatory commissions are giving more weight to competitive risks in setting the fair ROE (because investors are requiring a higher return to compensate for these risks). Investors in Hawaii electric utilities, however, are not being compensated for the "risk" that significant parts of their existing facility might be stranded due to advancements in technology and development of sophisticated new markets.

E. WHETHER THE UTILITY WOULD HAVE STRANDED COSTS IN PERIOD OF LOAD GROWTH

The HECO Companies' response addresses the situation where customer load and energy sales are "lost" as a result of the addition of DG/CHP systems. The loss in customer load and sales results in a loss of revenues. Some of the loss in revenues is offset by a reduction in variable costs (i.e., the fuel and variable O&M costs that vary with the production of energy). (Some "fixed" costs also may be variable in the long term.) The remaining lost revenues are termed "net lost revenues," or "lost margins," and represent the former contribution to fixed costs from the lost load and sales. If system load and sales growth is positive despite the load and sales lost to non-utility DG installations, then the net lost revenues will be replaced by new load and sales. Existing facilities can be used, at least to some extent, to serve the new load. Generally, however, the utility will already have added generation and transmission facilities (or incurred costs to be able to add facilities) in anticipation of new load and sales growth, and will have to add new distribution facilities to serve the new load. New generation and transmission facilities have to be planned many years in advance, and the utility may or may not be able to adjust its plans for changes in the rate of load growth due to factors such as non-utility DG. Thus, there may or may not be net lost revenues due to non-utility DG even in periods of load growth. (The special situation involving distribution facilities is addressed below.)

Technically, net loss revenues would not result in "stranded costs" (although there may be a lag in cost recovery until the utility's next rate case) unless the utility is barred by regulation from passing the costs on to other customers through higher prices, or is unable to do so due to market conditions.

The bottom line is that if and to the extent facilities installed for the use of DG customers are no longer needed to serve these customers, but can be used instead to serve new loads and sales, the costs of the facilities are unlikely to be stranded. This is more likely to be the case where system load and sales are growing despite the loss of load and sales to customer-sited DG.

The deployment of customer-sited non-utility DG is most likely to result in a bypass of the utility's distribution infrastructure, especially in the case where a customer installs enough DG to completely self-generate. Utility distribution infrastructure which serves a specific customer is subject to the electrical demands of that customer. If the customer's use of that utility infrastructure decreases, then that infrastructure may be stranded regardless of whether load growth is being seen on the electrical system as a whole. For example a distribution line may be installed to provide service to a customer's facility. If the customer were to install its own generation, the utility distribution infrastructure would be stranded to the degree that it is no longer used to serve the customer. Thus, during periods of load growth the utility would not be experiencing stranded generating costs, however it may be experiencing stranded distribution costs at specific locations due to the installation of customer-sited non-utility DG.

F. IS IT REASONABLE TO EXPECT IDENTIFICATION OF INDIVIDUAL PROJECTS OR PROJECT ZONES IN IRP? WHAT SPECIFIC MODIFICATIONS TO THE PROCESS SHOULD THE COMMISSION CONSIDER TO FACILITATE SUCH IDENTIFICATION?

It is not reasonable to expect that individual projects or project zones can be identified in IRP. IRP, by its nature, analyzes resources at the system level prior to identification of specific projects. Additionally, individual DG projects are generally too small to impact the timing of central station generation or transmission line additions. For these reasons, DG must first be considered on a generic basis and the site-specific impacts a particular project may have on the system are not considered. HECO T-1 at 36.

In addition, DG projects are typically internal combustion engines and projects are driven by customer requirements (equipment replacements, facility upgrades). See HECO T-1 at 9. Since customer requirements are constantly changing so too are customer plans for DG which makes it difficult to forecast DG by geographic area.

The CA's position is that the PUC should require the utility to identify specific areas or types of areas where DG would be most beneficial, to the extent that this is practical to do so. Tr. 85 (12/09/2004) (Herz). Even if it were reasonable to identify "load pockets" in the IRP process, there are many transmission considerations that complicate the consideration of DG to address the "load pockets" in IRP. HECO T-4 at 13. In addition, the need for DG resources to be firm capacity and the likelihood for liquidated damages makes it difficult to implement a system benefit incentive for DG. Tr. 65-66 (12/09/2004)(Ishikawa); Tr. 68 (12/09/2004) (Gregg).

The identification of project zones is not necessary. Hess stated load pocket information is not needed for CHP. Tr. 57-58 (12/09/2004) (Gregg). The information required by Hess from the utility is the short-circuit impact or fault-current impact. Tr. 57-58 (12/09/2004) (Gregg).

G. UNDER EACH OF THE TWO SCENARIOS FOR PARTICIPATION IN DISTRIBUTED GENERATION - UTILITY PARTICIPATION AND UTILITY AFFILIATE PARTICIPATION – WHAT RULES AND RESTRICTIONS ARE NECESSARY TO ASSURE THAT THE COMPETITION BETWEEN NON-UTILITY PROJECTS AND UTILITY-OWNED (OR AFFILIATE-OWNED) PROJECTS IS EVENHANDED, MEANING THAT THE UTILITY OR UTILITY AFFILIATE HAS NO UNEARNED COMPETITIVE ADVANTAGE? (NOTE: ALTHOUGH SOME PARTIES AND PARTICIPANTS MAY BELIEVE THAT THERE IS NO POSSIBILITY OF UNEARNED COMPETITIVE ADVANTAGE, WHILE OTHER PARTIES AND PARTICIPANTS MIGHT BELIEVE THAT ANY PARTICIPATION BY THE UTILITY OR AN AFFILIATE WILL DISTORT THE MARKET, THE COMMISSION URGES PARTIES AND PARTICIPANTS TO SUSPEND THOSE BELIEFS FOR PURPOSES OF THIS QUESTION AND ASSIST THE COMMISSION'S CONSIDERATION OF PRACTICAL APPROACHES.)

The premise for this question as stated is that for competition between non-utility projects and utility or utility affiliate-owned projects to be "evenhanded", the utility or utility affiliate should have no unearned competitive advantage. Evenhanded competition, however, should also mean that non-utility projects should not enjoy any unearned competitive advantage over utility or utility affiliate projects. Put another way, any rules and restrictions should not create any competitive disadvantage to the utility or utility affiliate.

In fact there are circumstances that make it more challenging at times for the utility to develop CHP than a non-utility entity. Non-utility CHP systems may offer quicker installation schedules compared to utility systems, to the degree that the utility needs to obtain PUC approval for projects done under Rule 4. The non-utility provider also has more flexibility in providing additional services and equipment that would otherwise be considered below the line from the utility's standpoint. Unregulated competitors also can offer their products and services without open review of their prices or terms and conditions of service, as must be done by the utility before the Commission.

The utility has rightfully earned several advantages. The utility rightfully has the advantage of being respected by customers as a long time established Hawaii company, likely to be here for the long term. The utility has rightfully earned the ability to capitalize on its long experience in designing, installing, operating and maintaining power generation equipment. The utility should also have the ability to leverage its bulk buying power for goods and services to the advantage of its ratepayers.

Utility Participation Scenario

Utility participation in DG brings with it the ability of the Commission to oversee utility DG projects. The advantage of such regulation is that the interests of both the CHP customer and non-participating electric customers can be considered, as opposed to a completely unregulated approach where there would be no mechanism to protect the interests of non-participating customers. Rules and restrictions are required to ensure that the utility is (1) fairly applying interconnection standards to both utility and non-utility DG projects, (2) fairly structuring its CHP pricing, and (3) providing benefit to non-participating electric customers as well as CHP customers.

<u>Interconnection</u>.

All distributed generation installations, whether utility or non-utility owned, should be subject to technical interconnection requirements to ensure that the DG installations will not cause damage to, or pose a safety hazard on, the electric transmission and distribution system, and conversely, to ensure that the DG systems are not damaged themselves. In order to assure this, the PUC, as it has already done with Rule 14.H., should establish a DG interconnection tariff, interconnection standards, and form of interconnection agreement. The Consumer Advocate should review the tariff, standards, and form of agreement.

The process of going through an interconnection review should not create any unfair advantage to the utility, from the standpoints of (1) delaying non-utility projects and expediting utility projects, (2) unfairly applying interconnection requirements on non-utility projects but not requiring them for utility projects, or (3) allowing the utility to use non-utility project information for competitive purposes. To monitor and ensure that such activities are not taking place, the utility should be required to file regular reports to the Commission on the progress of interconnection reviews for both utility and non-utility DG projects. Such reporting should highlight whether or not the interconnection review and agreement process is systematic and objective.

In addition, the interconnection review process should regularly be assessed by the utility and frequent users of the process – both utility and non-utility – for opportunities to improve efficiency and consistency in application of interconnection requirements. In no case, however, should the process be streamlined at the expense of the ultimate objective of interconnection review, that is, to ensure safety and protect the utility T&D system as well as the DG equipment. Additionally, consistency in applying interconnection requirements should not be misconstrued to mean that all projects will be subject to the same technical interconnection requirements. A one-size-fits-all approach is not appropriate, as project specific factors may cause certain projects to be subject to more lengthy reviews and interconnection requirements than other projects. Consistency here means that there should not be any double standard between utility or non-utility projects.

CHP Pricing

The utility's pricing for CHP service should properly charge the CHP customer for the costs of that service, without any inappropriate subsidy or cost break that would provide an unfair competitive advantage to the utility. If the utility uses a bundled approach to its CHP pricing structure, as HECO proposes to do, than the utility's bundled price for CHP service, backup service and supplemental service[37] should be equal to or greater than the unbundled cost.[38] The utility should show to the PUC that revenues from unbundled prices (i.e., the CHP service priced at cost, and the supplemental and backup services price based on the existing tariff – since that is the price charged to customers with customer-owned CHP systems) would equal or exceed revenues from the proposed bundled prices. If unbundled pricing revenues are higher, then the bundled CHP price would have to be raised (by reducing or eliminating the CHP electricity discount, and/or by increasing the thermal fee).

If the utility wanted to justify a lower than unbundled CHP system cost price, for example due to central station generation deferral benefits obtained by all customers, then it could be required to "level the playing field" for third-party or customer-owned CHP systems that provide the same generation deferral benefit by reducing their cost for standby service by the same amount.[39]

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37 Customers with loads that are partially served by an on-site CHP system receive three types of service. These include (1) CHP system service, which is the electrical capacity and energy supplied by the CHP system generating unit(s), and the thermal energy supplied by the system (which can drive an absorption chiller, and thereby further displace the use of utility system electricity), (2) "supplemental service," which is the electrical capacity and energy supplied by the electric utility system that is used by the customer in addition to that regularly supplied by the CHP system generating unit(s), and (3) "backup service," which is the electrical capacity and energy supplied by the electric utility system during scheduled or unscheduled outages on partial unavailability of the CHP system generating unit(s) (and absorption chiller). Backup service provided during scheduled outages is sometimes referred to as "maintenance service."

38 The CA originally proposed that the utilities' pricing be unbundled. The Companies showed why that would not be a practical approach. The CA and the utilities then agreed with the requirement as restated above.

39 This option to the utility would not be available until the Commission approved standby charges.

Non-Participating Customer Benefits

The utility should show that non-participants would not be burdened by the utility's provision of CHP service. In other words, it should be shown quantitatively that utility customers are better off with utility CHP than without. HECO performed a detailed quantitative analysis of the various costs and benefits of its proposed utility CHP program and filed that analysis in its CHP Program application in Docket No. 03-0366. This analysis needs updating based on current information. (In the Rule 4 contract filings in Docket Nos. 04-0314 and 04-0366, HECO and HELCO indicated that various revisions needed to be made to the analysis such as updating heat rate assumptions and correcting an understatement of facility fee revenue. In light of HECO's current need for additional generation, and its expected inability to add central station generation before 2009, the updated analysis should identify the method used to value the generation deferral benefit of CHP in the 2006-2009 timeframe.)

Not Required – Rules Governing Access to Information

No rules or restrictions are required regarding access to information. Certain parties to the docket allege that the utility enjoys an unfair advantage in its knowledge of locations on its T&D system that could better accommodate DG, and in its access to customer energy data. As described on page 28 of HECO T-1, however, all CHP developers are already aware that the most likely candidates for CHP systems are facilities with continuous thermal loads such as hospitals and hotels. Once a potential CHP host is identified, information regarding the host's electrical usage can be obtained directly from the host or from the utility if the host authorizes the release of the data.

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

Not Required – Standby Charges for Utility Projects

Certain parties to the docket have also posited that the utility should be required to assess standby charges to utility CHP projects in order to "level the playing field" with non-utility projects. As stated on page 31 of HECO RT-1, this would not serve any useful purpose. The Company would have to charge different rates than those based on its rate schedules for CHP system electricity (i.e., for CHP service), charge for "supplemental" service (i.e., electricity from the grid) based on its rate schedules, and for backup service based on Rider A. If the Company's CHP system performed well, it would receive more revenues for CHP service and less for back-up service. If the CHP system performed poorly, the Company would receive fewer revenues for CHP service and more for back-up service. The customer would be indifferent (as long as the CHP system thermal output was sufficient for its needs) since the utility would provide both services. Rider A makes sense where the providers of CHP service, and backup and supplemental service, are different entities.

Not Required – Incentive Payments for T&D Benefits

The utilities should not be required to establish "incentive payments" for third-party or customer-owned CHP systems in order to acquire hypothetical transmission and/or distribution ("T&D") deferral benefits. While there may be T&D benefits in concept, they cannot be predicted or quantified at this time. That also means that the utilities should not be allowed to calculate an additional discount for their CHP services (below that which is justified by the analyses described above) based on alleged T&D benefits.[40]

Unregulated Utility Affiliate Scenario

The most straightforward way of preventing an unregulated utility affiliate from enjoying unearned competitive advantage over other DG developers is to require that the affiliate be separately capitalized and staffed from the utility. Any transactions between the utility and the utility affiliate would be conducted and scrutinized by the PUC in the same manner as if the utility were to do business with a non-utility entity.

As stated at HECO T-1, page 20, however, the Companies do not anticipate participating in the DG market if only a separately capitalized, separately staffed affiliate was allowed to participate. The needs of participating and non-participating customers can be served if the program is provided on a regulated basis, while the impact on non-participating customers would be a non-factor for an unregulated supplier of CHP systems.

The Companies' reasons for providing CHP system services as a regulated utility service were presented at length in its various testimonies and in the CHP Program application. The expertise and resources to provide such services reside in the utility. The customers desiring such services are utility customers. The objectives of the program are utility objectives. Utilities are in a better position to provide customers with the option of having the services provider be

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40 If, however, a situation does arise where the utility wants to offer an additional discount in a particular situation, the utility could be required to quantify the amount of the additional discount and to offer that amount as an incentive to third-parties or customers (which incentive could be in the form of a discount to their PUC-approved standby charge) if a customer contractually commits to install a non-utility system instead.

the entity that owns, operates and maintains CHP systems, which should increase the market for such systems.

The Companies might consider providing CHP systems services on an unregulated basis, if that was the only option, through the utilities themselves, in the manner that TGC provides both unregulated propane services and regulated SNG and propane services within the same entity. However, this would present opportunities for conflicting objectives between the regulated and unregulated businesses of the Companies, which would not be present if the Companies provided CHP systems services on a regulated basis.

DG DOCKET BACKGROUND

1. DG Investigation (Docket No. 03-0371)

On October 21, 2003, the Commission issued Order No. 20582 in Docket No. 03-0371, which initiated a proceeding to investigate DG in Hawaii. The Commission anticipated that other matters related to the DG generic proceeding may be considered on a "case-by-case basis". Issues to be addressed in the DG docket included: (1) addressing interconnection matters, (2) determining who should own and operate distributed generation projects, (3) identifying what impacts, if any, distributed generation will have on Hawaii's electric distribution systems and market, (4) defining the role of regulated electric utility distribution companies and the commission in the deployment of distributed generation in Hawaii, (5) identifying the rate design and cost allocation issues associated with the deployment of distributed generation facilities, and (6) developing revisions to the integrated resource planning process, if necessary.

The Commission made the electric utilities in Hawaii and the CA parties to the proceeding, and invited interested energy service providers and other business, environmental, cultural and community groups to file motions to intervene or participate in the docket, and a number of entities have filed such motions. By Order No. 20832 issued March 3, 2004, the Commission (1) granted the motions to intervene of Hawaii Renewable Energy Alliance, Life of the Land, Johnson Controls, Inc. ("JCI"), Pacific Machinery, Inc. ("PMI"), Hess Microgren, LLC, The Gas Company, LLC ("TGC"), and the County of Maui, (2) granted the motions to intervene without participation of the County of Kauai and the Department of Business Economic Development and Tourism ("DBEDT"), and (3) ordered the parties and participants to determine the procedures and schedule with respect to the proceeding, to be set forth in a prehearing order. PMI, JCI, TGC and DBEDT subsequently withdrew from the docket.

On April 2, 2004, the parties and participants entered into and filed a proposed stipulated prehearing order. By Prehearing Order No. 20922, issued April 23, 2004, the Commission adopted the proposed issues in part, the proposed procedures, and the proposed schedule with modifications. The order includes 13 planning, impact and implementation issues.[1] The planning issues address (1) forms of DG (e.g., renewable energy facilities, hybrid renewable energy systems, generation, cogeneration) are feasible and viable for Hawaii, (2) who should own and operate DG projects, and (3) the role of regulated electric utility companies and the Commission in the deployment of DG in Hawaii. The impact issues address (1) the impacts, if any, DG will have on Hawaii's electric transmission and distribution systems and market, (2) the impacts of DG on power quality and reliability, (3) utility costs that can be avoided by DG, (4) externalities costs and benefits of DG, and (5) the potential for DG to reduce the use of fossil fuels. Implementation issues include (1) matters to be considered to allow a DG facility to interconnect with the electric utility's grid, (2) appropriate rate design and cost allocation issues that must be considered with the deployment of DG facilities, (3) revisions that should be made to the integrated resource planning process, and (4) revisions that should be made to Commission rules and utility rules and practices to facilitate the successful deployment of DG. The parties and participants were also allowed to address issues raised in a prior informal complaint, but not specific claims made against any of the parties named in the complaint. See HECO T-1 at 1-3.

Pursuant to the Prehearing Order, the remaining parties and participants filed Preliminary Statements of Position ("PSOPs"), responses to IRs regarding the PSOPs, direct testimonies and exhibits, responses to IRs and SIRs regarding the direct testimonies, rebuttal testimonies and exhibits, responses to RIRs regarding the rebuttal testimonies, and responses to PUC IRs.

[1] Issues 1 and 12 were the same issue.

Hearings were held on December 8, 9 and 10, 2004, using a panel hearing format, as directed by the Commission by letter dated November 16, 2004, and confirmed by Order No. 21489 (December 1, 2004). Simultaneous Post-Hearing Opening and Closing Briefs were made due four weeks and seven weeks, respectively, after the hearing transcript is completed and filed (which occurred on February 7, 2005). By letter dated December 28, 2004, the Commission also identified seven specific issues to be addressed in the Opening Briefs, in addition to the other matters.

2. <u>Competition Docket (Docket No. 06-0493)</u>

The DG Docket was initiated by the Commission as a follow up to its competition investigation, which was opened at the end of 1996 and closed in 2003. By Order No. 96-0493, issued December 30, 1996 in Docket No. 96-0493, the Commission instituted a proceeding to identify and examine the issues surrounding electric industry competition and determine the impact of competition on the electric utility infrastructure in Hawaii. The Commission issued final Decision and Order No. 20584 ("D&O 20584") on October 21, 2003, which closed the competition docket instituted in 1996. The Commission determined that no action would be taken in the docket to implement retail electric competition or to substantially change the regulatory framework for the electric industry in Hawaii at this time. The Commission determined that it was in the public interest to work within the current regulatory system to strive to improve efficiency within the electric industry, and opened investigative dockets on competitive bidding and distributed generation to move toward a more competitive electric industry environment under cost-based regulation.

3. <u>Informal Complaint (No. IC-03-098)</u>

An informal complaint was filed against the Companies on July 2, 2003 by three vendors of distributed generation ("DG")/combined heat and power ("CHP") equipment and services in the form of a July 1, 2003 Letter ("7/1/03 Letter") to the Commission from the Vice-President for PMI, the Branch Manager for JCI, and the Manager of Construction for Noresco, Inc. ("Complainants"). The 7/1/03 Letter was designated an informal complaint (Informal Complaint No. IC-03-098) and was referred to the Companies for response by Commission letter dated July 9, 2003. In addition, the Commission provided information requests ("IRs") regarding MECO's research, development and demonstration ("RD&D") project at the Grand Wailea Resort Hotel & Spa on Maui, and the Companies' Teaming Agreement dated February 11, 2003 with Hess Microgen LLC ("Hess"), which has since been terminated. HECO RT-1 at 26. Among other requests, the Complainants proposed that the Commission open a proceeding to investigate the electric utilities' provision of CHP services and the teaming agreement, and to issue rules or orders to govern the terms and conditions under which the electric utilities will be permitted to engage in utility-owned DG at individual customer sites. The Companies submitted their response, in which they outlined their plans for a CHP tariff, on August 5, 2003. By letter dated September 4, 2003, the Commission indicated that it intended to open a generic investigative docket regarding DG, and to close the investigation regarding the informal complaint.

PMI and JCI initially intervened in the DG Docket, but subsequently withdrew.

4. <u>CHP Program (Docket No. 03-0366)</u>

On October 10, 2003, the HECO Companies filed an Application to the Commission for approval of a proposed utility-owned Combined Heat and Power ("CHP") Program in Docket No. 03-0366. The HECO Companies requested approval of each of their proposed CHP

Program and related tariff provisions (Schedule CHP, Customer-Sited Utility-Owned Cogeneration Service). Under the CHP Program and Schedule CHP, the HECO Companies proposed to offer CHP systems to eligible utility customers on the islands of Oahu, Maui, and Hawaii as a regulated utility service. They also indicated that they would request approval on a contract-by-contract basis for CHP system projects that fall outside the scope of the proposed program. Implementation of a CHP Program was scheduled to begin in 2004, if authorized by the Commission. The CA is a party to the proceeding, and a number of entities filed motions to intervene or participate in the docket.

On October 31, 2003, the CA filed a Statement of Position in Docket No. 03-0366, in which it recommended that the CHP Program docket be consolidated with the DG docket, or in the alternative, be suspended so as to not "affect the Commission's analysis" in the DG docket. The CA proposed that the Commission analyze situations "where an existing end-user may leave the grid to pursue non-utility options" on a "case-by-case" basis.

By Order No. 20831, issued March 2, 2004 in Docket No. 03-0366, the Commission ordered that the CHP Program application "is suspended until further order of the Commission." The Commission indicated that its DG docket is intended to "form the basis for rules and regulations deemed necessary to govern participation into Hawaii's electricity market through distributed generation." The Commission noted that "[e]very effort will be made to hold hearings on Docket No. 03-0371 by the end of 2004 and immediately issue a decision and order in that docket."

5. <u>Rule 4 Applications</u>

After filing the CHP Program application, the Companies continued to develop selected CHP system projects for customers, with the understanding that, for individual CHP projects to be installed under service contracts, Commission approval is required under Rule 4 of HECO's tariff. In opening its generic DG investigation in Order No. 20582, issued October 21, 2003 in Docket No. 03-0371, the Commission indicated:

> "Since it would be unreasonable to defer consideration of all future related filings with the commission that may be affected by this proceeding, the commission may consider those related matters on a case-by-case basis. To the extent that there is a public interest served in determining an outcome in these matters prior to the completion of this proceeding, we will do so. Such an outcome, however, may need to be interim in nature, pending our final disposition of this docket."

On October 28, 2004, HECO filed an application for approval of a CHP Agreement with Pacific Allied Products, Ltd., dated September 8, 2004, and for other approvals necessary to provide service to Pacific Allied, using a utility-owned CHP system, on a regulated basis. On December 17, 2004, HELCO filed an application for approval of a CHP Agreement with Koa Hotel, LLC dated October 6, 2004, and for other approvals necessary to provide services to the Sheraton Keauhou Bay Resort and Spa, using a utility-owned CHP system, on a regulated basis.

On January 21, 2005, the Commission issued Order No. 21555 in Docket No. 04-0314, and Order No. 21554 in Docket No. 04-0366, suspending HECO's application for approval of the Pacific Allied CHP Agreement and HELCO's application for approval of the Koa Hotel (Sheraton Keauhou) CHP Agreement, "until, at a minimum, the matters in Docket No. 03-0371 have been adequately addressed." Due to the regulatory and schedule uncertainty, Pacific Allied terminated its CHP Agreement by letter dated February 9, 2005, as noted in HECO's Withdrawal of Application filed March 4, 2005.

6. <u>Interconnection Tariffs (Docket No. 02-0051)</u>

The HECO Companies filed proposed interconnection tariffs, including interconnection standards and a standard form of interconnection agreement, in January 2002, and submitted modifications agreed to by the CA in September 2002. The Commission conditionally approved the tariffs by Decision and Order No. 19773 ("D&O 19773"), issued November 15, 2002 in Docket No. 02-0051 (Consolidated). The Companies and the CA noted the Commission's observations in D&O No. 19773, and jointly submitted revisions in February 2003. The Companies' revised Tariff Rule Nos. 14.H were approved on March 6, 2003 by Decision and Order No. 20056.

The Companies file annual reports (due at the end of January of each year) and quarterly reports (due at the end of April, July and October of each year) on the status of establishing interconnection agreements for distributed generation customers.

VIRTUAL POWER PLANT PROPOSAL

1. County Of Maui Proposal

The County of Maui ("COM") has recommended that "the Commission direct MECO to modify its planned Capacity Buy-back ("CBB") program into an expanded virtual power plant program." COM T-1 at 16. In addition, COM has urged the Commission to "[d]irect the utilities to examine the creation of a virtual power plant from existing customer-owned emergency generators, . . . [and] report on the costs and benefits of doing so." COM T-2 at 97. In addition, COM has proposed that: "[t]he Commission should direct each utility to develop a plan to implement a virtual power plant in its service territory. This should include an inventory of possible generators, development of a plan to install synchronization equipment and central dispatch capability, and development of the contractual and institutional framework needed to make the program a success." COM T-2 at 101.

By creating such a VPP, COM claims that "MECO would acquire access to a low cost and flexible 'virtual' backup power plant, consumer-generators would generate revenues, and onsite and grid reliability would improve." COM Preliminary SOP at 4. In actuality, improving the reliability of emergency generators, rather than providing a system benefit, appears to be the primary motivation for COM's Proposal. See Tr. (12/09/04) at 77 (Kobayashi).

COM has not provided any detailed analysis or other basis that would justify the proposed direction that MECO modify its planned CBB Program. In addition, its recommendation appears to go well beyond the scope of this docket. The HECO Companies, however, are agreeable to undertake a feasibility study of the virtual power plant concept for the island of Maui within the next major MECO IRP review (i.e., MECO IRP-3), provided that the full costs of the study are recoverable via the IRP Cost Recovery Provision. HECO RT-3 at 6, 14.

2. Issues And Concerns With VPPs

According to COM, VPPs "are generally considered to be a network of DG systems, integrated together with computer monitoring and control equipment, to allow a system operator to dispatch some or all of the networked DG systems as though they were one or more central generation power plants." COM T-1 at 16.

The HECO Companies have identified a number of issues and concerns that must be addressed in order for utilities to rely on VPPs to provide reserve capacity. HECO T-3 at 15. (Reserve capacity is the total amount of firm generating capacity on the system less the system peak demand. The Companies must maintain enough reserve capacity on the system to allow generating units to be taken out of service for maintenance and to allow for the unexpected loss of generating capacity due to unplanned outages of other generating units. Reserve capacity is commonly referred to as "reserve margin." HECO T-3 at 14.)

Backup or emergency generators are normally installed by large customers to provide electrical power to their essential services (such as emergency lighting and critical electronic equipment) in the event power from the utility is not available. It is likely that when there is a system emergency and the utilities need backup power from such "virtual" power plants, the large customers would be affected by the same system emergency and would be calling upon their emergency generators to provide power. In such cases, the "virtual" power plants would not be able to provide backup power to the grid. HECO T-3 at 15. With respect to actual availability of the emergency generators during times of system need, COM conceded in response to CA-IR-47 that the utility's dispatch control of the customer-sited emergency generators would be "subject to pre-emption by the owner for on-site requirements." HECO RT-3 at 8.

In addition, the air permit customers must obtain to operate their emergency generators may not permit operation in parallel to the grid. The air permit may allow the unit to operate for only a very limited number of hours for testing or serve the customers' internal loads for bona fide emergencies only. HECO T-3 at 15. Even if the air permits did permit the units to operate for a significant number of hours, neighbors of the customers with the emergency generators may object to operation of the units beyond testing and emergencies. Objections may be based on noise, emissions and increased truck traffic due to increased fuel deliveries. HECO T-3 at 15-16.

Further, the utility would have no control over the testing and maintenance practices for the emergency generators and thus would have no control over their availability or reliability. HECO T-3 at 16. The utility may also lack adequate dispatch control over the units since the emergency generators would be designed for a customer's specific emergency needs and not necessarily for the needs of the grid. HECO T-3 at 16. Moreover, fuel storage capacity may be sufficient for emergency situations of short durations, but may be inadequate for sustained grid backup needs. HECO T-3 at 16.

COM claimed that, "[i]n order to eliminate rolling blackouts that had plagued the island, HELCO contracted with several large customers with emergency generators to switch some of their loads to their own generators during high-load hours." COM T-2 at 52. However, COM was mistaken. HELCO had no contracts with any customer with emergency generation to switch a portion of their loads to their own generators during high-load hours. Rather, during certain periods, HELCO contacted large customers to voluntarily curtail their demand to try to prevent demand from exceeding available supply. These customers were under no obligation to do so, but chose to reduce their demand to the extent possible. Some customers may have operated their standby generators to remove their dedicated emergency loads from the system demand, but the generators were not operated in parallel with the system. HECO RT-3 at 10-11.

3. Distinctions between IPPs and VPPs

COM's proposal for VPPs fails to recognize crucial distinctions that exist between Independent Power Producers ("IPPs") that can supply firm capacity (and energy) and the VPP concept. First, IPPs provide power only to the electric utilities. In contrast, COM's proposed "virtual" backup power plants would serve either a large customer's internal load under emergency conditions or the electric utility. HECO T-3 at 17. IPPs, who provide power to the HECO Companies under Power Purchase Agreements ("PPAs"), are able to address/deal with these issues because the PPAs contain provisions that provide assurances that the IPP will deliver capacity and energy to the utilities within certain performance and reliability standards when needed. The PPA's also specify penalties for non-delivery or sub-standard performance. HECO T-3 at 16.

Unlike IPPs, owners of emergency generators do not install the generators for the purpose of serving the needs of the utility grid. In addition, such owners would probably not choose to assume risks they do not now incur. For these reasons, it appears unlikely that owners of emergency generators would voluntarily accept the types of penalty provisions to which IPPs agree, and the utilities would not be able to unilaterally force these owners to accept such provisions. Of course, while owners of existing emergency generators could voluntarily choose to accept the type of performance and reliability standards along with the penalties for non-delivery or sub-standard performance as described in the referenced testimony, it is unlikely that they would do so. HECO Companies' Response to HREA-HECO-T-3-IR-5; see HECO T-3 at 16-17.

Thus, the HECO Companies would need assurance that these "virtual" backup power plants, like the IPPs, would be available and capable of providing capacity as needed by the system. Until the above concerns can be resolved and it can be demonstrated that "virtual" backup power plants can reliably and cost-effectively provide reserve capacity, the HECO Companies do not plan to integrate these types of resources into their long-range resource plans. HECO T-3 at 17.

4. **VPPs May Be Ineffective In Practice**

COM identified Public Service of New Mexico ("PNM") as an electric utility that aggregates networks of customer-sited generators together into 'virtual power plants'. HECO-COM-DT-IR-1; HECO RT-3 at 7. (It appears that an independent project developer, Celerity Energy, developed and coordinated PNM's VPP program under contract to PNM. Celerity Energy raised investment capital and signed up customers for the program, upgraded the units, connected the units to a communication system, and was responsible for the daily operation and all maintenance of these units. See HECO RT-3 at 7.

While PNM has acquired some capacity from a so-called "virtual power plant," the amount is very small in comparison to its overall system size. HECO RT-3 at 7. Despite the program's commencement in 1999, Celerity Energy has delivered about 6 MW in capacity from the VPPs. In contrast, PNM's system peak is about 1,600 MW. See HECO RT-3 at 7. In addition, PNM has indicated that the units included in the VPP do not necessarily meet the utility's needs and, therefore, "they do not rely heavily upon it." Furthermore, unlike Hawaii utilities, PNM is interconnected to other utilities so that it can purchase power from neighboring utilities as needed. The HECO Companies have no such option, since neither HECO, MECO nor HELCO is interconnected to any other grid. HECO RT-3 at 8.

5. <u>Commercial and Industrial Load Control Program</u>

HECO has developed and filed with the Commission a Commercial and Industrial Load Direct Control Program ("CIDLC Program") in Docket No. 03-0415. This program proposes that a customer may nominate all or part of its load to be remotely interrupted via under frequency relay or dispatched by the utility when there is insufficient generation to meet peak demand. The loads under this program may be discretionary loads that the customer allows to be interrupted or may be load that can be transferred to a stand-by generator. Under this program, customers will receive payments to facilitate installation of equipment needed to participate and to facilitate on-going maintenance and operation of this equipment. HECO RT-3 at 9.

COM describes the virtual power plant as "a process of knitting together existing customer emergency generators into a viable utility reserve resource to meet extreme conditions". COM T-2 at 50. HECO's CIDLC Program already provides a mechanism to use stand-by generators as a resource similar to the virtual power plant concept. However, the CIDLC Program also goes beyond the use of stand-by generators and allows the utility to access additional resources that customers may have available. Narrowly considering only stand-by generators would result in capturing only a part of these potential additional resources, which include loads designated by a customer that it can interrupt at its own discretion, such as water pumps, chillers or certain processes in industrial production lines. Furthermore, there is a significant difference between capacity that may be available from a VPP and that which can be provided by the CIDLC Program. Under the CIDLC Program, the nominated portion of the customer's load can be interrupted immediately through an underfrequency relay or through manual control with one hour notice by the utility. If the customer has a standby generator, the customer may decide to turn on the generator to serve the internal load that was interrupted at his or her discretion. The customer's decision does not affect the utility's ability to receive the capacity from the interrupted load. In contrast, with the VPP, the customer's standby generator must be turned on for the utility to receive the capacity. Hence, if the generator(s) are not turned on – due to operational or maintenance problems, because the air permit limits have been exceeded, or for some other reason – the utility will not receive the capacity. HECO RT-3 at 10.

6. <u>Conclusion</u>

The HECO Companies have a number of issues and concerns with the VPP concept, including the actual availability of the emergency generators during times of system need, air permit limitations, noise, emissions and increased fuel truck traffic, lack of control over testing and maintenance practices for the emergency generators, potential lack of adequate dispatch control, and fuel storage capacity. Moreover, HECO is implementing a Commercial and Industrial Direct Load Control Program that will allow customers to take advantage of their emergency generators, to the extent that proves to be feasible, to provide interruptible "capacity" to the company. However, the HECO Companies are agreeable to undertake a feasibility study of the virtual power plant concept for the island of Maui within the next major MECO IRP review (i.e., MECO IRP-3), provided that the full costs of the study are recoverable via the IRP Cost Recovery Provision. HECO RT-3 at 14.

RATE DESIGN ISSUES

A. IMPACT FEES

1. COM Proposal

COM recommends that the Commission implement connection charges (or impact fees) for new customers and expanded loads. COM T-2 at 97. COM claims that: "[t]he addition of new customers requires additional generation, transmission, and distribution plant and the associated cost." COM T-2 at 41. Furthermore, since "[n]ew customers add more to cost than to revenues for the utility, [they] should pay a connection charge (impact fee) designed to recover this shortfall at the time of connection to the system." COM T-2 at 56.

The HECO Companies should not be required to charge an impact fee (i.e., a non-refundable contribution in aid of construction) to only those new customers who are adding load to the system for the capital costs of new generating facilities (or for the incremental cost over the embedded capital costs of existing generation). HECO RT-1 at 49.

COM's proposal is troubling. An impact fee requires the implementation of an up-front charge on new or expanding customers to cover the installed facilities and equipment cost of generation and transmission capacity. COM proposes to establish this generation impact fee for new and expanded loads to recover the cost of future new power plants. Specifically, COM proposes a generation impact fee of $2,000 per kW of the new customer's connected load. The COM is proposal extends to all customers – both residential and non-residential. COM's proposal results in a generation impact fee of $10,000 for a typical new residential customer, based on a residential customer's typical connected load of approximately 5 kW.[1] HECO RT-5 at 8.

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1 In addition, impact fees can adversely impact the new housing market. Impact fees result in a new housing customer paying for an additional upfront cost that would be included in the cost of the new

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

2. Impact Fees are Contrary to Current Rate Design

In Hawaii, electricity customers generally are not charged differential rates based on their vintage, and members of a customer class are treated equally. For example, rural residential customers are generally charged the same as urban residential customers, even though it may cost more on average to serve rural customers. The HECO Companies' line extension policy currently includes a form of connection charge.[2] However, there is a fundamental difference between the facilities covered by the line extension policy and the facilities associated with generation and transmission. Unlike line extensions, which involve distribution facilities that are dedicated to serve a particular customer or a distinguishable set of customers, generation and transmission facilities, are used in common by all customers on the network. "Dissecting" facilities that clearly benefit the network as a whole based on individual customer vintage is inconsistent with proper allocation of shared network costs and discriminatory. HECO RT-5A at 20.

3. Impact Fees (If Fairly Designed) Are Impractical

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house. This could add to the amount of money that would have to be financed by a purchaser. Tr. (12/10/04) at 107-08 (Gegax).

2 The only contributions required under MECO's tariff are those specified by Rule 13, which requires non-refundable contributions to cover the cost difference between an overhead and an underground distribution system when required or requested for a subdivision, and to cover the cost of other "special facilities." In addition, advances, which are subject to refund, are required when the cost of individual line extensions exceed 60 month's estimated revenue, and when overhead lines are extended to subdivisions or developments in advance of service requests by individual customers. HECO RT-1 at 49-50.

Imposing an impact fee on new or expanding customers would create new sub-classes of customers based on vintage. This would require the Commission and the utility to implement detailed accounting for the amounts collected from new customers and distinguish between capacity additions caused by growth versus capacity additions that are necessary to replace existing capacity. Even if the Commission establishes such accounting rules, the costs per unit of generation and/or transmission capacity can be expected to change through time. They can increase or decrease depending on the current cost of equipment and possible technological innovation. HECO RT-5A at 17-18.

Replacement of existing capacity would change the average cost of that existing capacity. Determining the fair and proper regulatory treatment of such average cost changes in the future when the utilities have multiple customer classes based on vintage would be very difficult. For example, a new generating unit may in part add new capacity on the system and in part replace existing capacity. In future cases, the Commission would be forced to consider methods for splitting the costs associated with the new generation plant between the vintages of customers.

For these reasons, the implementation and management of such a policy would be extremely burdensome on the regulatory process, if not unmanageable. HECO RT-5A at 18. There would be significant difficulties in structuring the rates for new customers if they were required to pay an impact fee covering the cost of new generation and transmission facilities or the incremental cost above and beyond the average embedded cost of existing generation and transmission facilities. Existing rates include the average embedded cost of existing generation and transmission facilities. Numerous complex questions would arise such as:

- Should generating units be "tagged" and identified with specific vintages of customers?

- If new customers were required to pay contributions in aid of construction, would new customers then be relieved of the necessity of paying demand charges?

- Would new customers pay lower energy charges because new generation and transmission facilities are often more efficient? If and when the next combustion turbine on Maui (which is originally used as a peaking unit, but is more costly than a simple peaker because it is designed to be incorporated into a combined-cycle unit) is incorporated into an energy-efficient combined cycle unit in the future, will the customers (and loads) that were assessed an impact fee be entitled to pay lower energy charges?

- When existing generation is replaced, or modified to accommodate new environmental requirements, or to replace existing components, should impact fees be charged to existing customers, and will new customers (or loads) that were assessed impact fees be excluded from the new assessment?

- Will existing customers who increase their use of electricity be assessed an impact fee, and will they receive a rebate if they subsequently decrease their use of electricity? (For example, should residential customers be charged impact fees because children are "added" to their families, thereby increasing their use of electricity, and should existing residential customers be rewarded with a rebate when their children leave home?)

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

As a practical matter, impact fees would be extremely difficult to establish and implement in an equitable manner. The need for new generation is driven by load growth and load growth is not caused just by new customer facilities and large renovations to existing facilities. HECO RT-1 at 50-51.

4. **<u>COM's Arguments Based On Marginal Costs Are Not Persuasive</u>**

COM supports its position on impact fees by noting that the addition of new generation tends to put upward pressure on rates. The premise is correct at least with respect to base rates, but COM's conclusion is not justified by the premise. The capital cost of new generating capacity exceeds the average depreciated capital cost of existing generating facilities that are in rate base. Thus, additions of new generating plant to rate base tend to cause upward base rate pressure, at least initially, although that is due in part to the manner in which rates are set. Plant generally is added to serve future load growth (i.e., in anticipation of need), not load growth that has already occurred. Other factors, such as increases in O&M expense (for which all customers are responsible), contribute to the ultimate need for a rate increase, but may not trigger an immediate rate increase because the contribution of increased sales to fixed costs (largely from new customers), delays the need for a rate case. (HECO's load and sales grew substantially from 1995 through 2003 without the filing of a rate case.) HECO RT-1 at 52-53.

It should be noted, however, that Maalaea Unit M19 was installed in September 2000 and MECO has not increased its base rates. In addition, rates are based on all costs, and not just rate base. In some cases, new generation may have lower fuel costs. For example, when the Hamakua Energy Partners (HEP) dual-train combined-cycle unit was added to HELCO's system on the Big Island in 2001 (through a power purchase agreement), there was a base rate increase authorized (in Docket No. 99-0207) that included the impact of the payments for firm capacity under the contract. However, customers also received the benefit of the lower energy costs associated with the facility, which were flowed through to customers through HELCO's ECAC. Thus, a base rate increase was triggered by the addition of the new capacity, but it was not indicative of the net rate impact on customers of adding the new capacity. HECO RT-1 at 53.

COM refers to the estimated cost of MECO's next generating unit, M18, and the estimated cost of the first CT that might be added at Waena, as support for its position that the higher costs of new generation warrant impact fees. However, the costs cited by COM are misleading unless the context in which they will be incurred is added. M18 will include the addition of a heat recovery steam generator and a steam turbine generator, and will allow M17 and M19 to be converted into an efficient dual-train combined cycle unit with lower fuel costs. As was indicated in the response to HECO-Companies-SOP-IR-11, the estimated cost for Waena Unit 1 (a nominal 20 MW simple cycle CT), including escalation and AFUDC, is $70.5 million in 2010 dollars. However, this estimate includes the cost of combustion turbine spare parts, a 1 MW black start diesel engine, an Uninterruptible Power Supply, a spare water treatment train, and redundant water and fuel pumps. Also, the Waena CT has the capability to be included in an efficient combined-cycle unit in the future, and its consideration for the next central station unit for MECO's system would take into account this potential. HECO RT-1 at 53-54; see Response to COM-HECO-DT-IR-20; see also Tr. (12/10/04) at 67-72 (Cross-Examination of Lazar); Tr. (12/10/04) at 116 (Lazar).

5. COM's Proposal Would Be Unfair

There are other problems associated with COM's proposal. COM makes a simplifying assumption that only new customers or existing customers with large renovations are responsible for load growth. However, existing customers, most of whom did not make large renovations, accounted for nearly half of the load growth on the island of Maui in 2003. Therefore, COM's proposal to allocate all of the marginal cost of new facilities to these new or expanding load customers is patently inequitable. New customers are only responsible for slightly more than half of the load increase, but would pay the entire marginal cost of new facilities under COM's proposal. HECO RT-1 at 54.

Mr. Lazar cited the use of impact fees by some municipal water and sewer utilities as support for his position. Tr. (12/10/04) at 35 (Lazar). Conceptually, charging impact fees for common facilities (rather than for main extensions) is problematic also. Moreover, as Dr. Gegax explained, the reason why municipals typically use impact fees is because it's another source of revenue that typically becomes commingled between the utility funds and the general funds, not because it's a conceptually sound way for utilities to charge for common facilities used to serve all customers. The benefits realized as a result of the incremental investment in common system facilities are realized by all customers. Tr. (12/10/04) at 42-43, 108 (Gegax).

Inherent in COM's discussion of generation capacity is the erroneous assumption that all capacity is of the same type and designed for the same purpose. In reality, the optimal mix of generation capacity types and the decision to add capacity to that mix depend on current system load characteristics. To begin distinguishing "new" capacity from "old" capacity is contrary to the economics associated with an optimal mix of generation. The mix of generation in the system must be viewed as one integrated resource serving all customers. It may be optimal at a particular point in time to add a base load plant with higher per-kW capacity costs than peaking capacity. The impact fee proposed by COM would hold new customers responsible for that new capacity despite the fact that its addition is optimal for the system as a whole. In other words, the entire set of generation capacity using a range of technologies is shared resource in the service of all customers regardless of their vintage. HECO RT-5A at 18-19.

Operation and maintenance ("O&M") costs for new generation capacity also vary greatly between types of generation. COM seems to suggest that new customers should be responsible for the capacity costs, but all customers would benefit from any reduced O&M costs of the new capacity.

In addition, the HECO Companies are unaware of any investor-owned electric utility that has implemented a rate design similar to that proposed by COM. Moreover, COM was unable to identify any utility that currently charges generation impact fees similar to those it proposes. See COM Response to HECO/Maui-DT-IR-3 and COM Response to HECO/Maui-DT-IR-23.d.

6. The Commission Has Rejected A Similar Proposal

The COM's proposal regarding hook up fees or impact fees is similar to COM Witness Lazar's proposal in a prior HELCO rate case (Docket No. 6999) made on behalf of the Consumer Advocate, which was rejected by the Commission. See Docket No. 6999, Decision and Order No. 11893 (October 2, 1992), at 101-102. In that docket, the Commission rejected the proposal, finding it to be discriminatory as it charged different rates for essentially the same service based simply on the customer's vintage.

The HECO Companies recommend that the Commission again reject the COM's proposal to establish a generation impact fee. HECO RT-5 at 9.

B. TERMINATION FEES

COM recommends that "...large customers be required to execute multi-year contacts with advance notice requirements to significantly change their demand on the utility." COM T-2 at 88-91.

Multi-year contracts with large customers may be appropriate for a number of reasons, and the risk of stranded costs is a valid consideration in designing rates where customers have competitive alternatives. As a general proposition, however, the concept of requiring large customers to execute multi-year contacts with substantial advance notice requirements as a pre-condition to significantly changing their demand on the utility could negatively impact economic development in Hawaii, could have the perverse impact of inhibiting the implementation of energy efficient CHP systems and energy efficient DSM measures that have the potential to significantly reduce customer usage of electricity supplied from the gird, and could negatively impact a customer's ability to make modifications to its own operations. For example, such a "contract" could be an obstacle to a customer expanding its own facilities and could negatively impact a hotel that has to temporarily close a wing during a tourism slump. HECO RT-1 at 55-56.

It is not the term of the "contract" that would be a problem. What the COM has not indicated is that such a contract would be ineffective unless a substantial fee was assessed if the customer changed its load level or left the system without giving the required notice. Thus, it appears that the COM is proposing a form of termination or "exit" fee when a customer reduces its load or leaves the system, and a form of "impact" fee when the customer increases its load. While there are circumstances under which such an early termination fee can be justified (such as when a customer contracts for a special rate arrangement, or receives a special benefit to be "amortized" over some period of time)[3], the ramifications of such a fee should be fully identified and explored before the fee is imposed on an across-the-board basis. HECO RT-1 at 56; see Response to CA-SOP-IR-23.

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3 See Response to COM-HECO-DT-IR-46.

As stated in the Companies' Preliminary Statement of Position (at page 32): "While the Companies currently do not intend to propose service termination charges where customers terminate or substantially reduce the level of the electricity supplied by the electric utility (and substitute other options) to address these types of issues, the appropriateness of having service termination charges was raised in the Competition Docket, Docket No. 96-0493." As stated, the Companies currently are not proposing such service termination charges. The service termination charges discussed in the Competition Docket were identified in the Companies' Final Statement of Position filed October 16, 1998 in Docket No. 96-0493, in Attachment D (at 14-15), and in Exhibit 15 to Attachment D (at 75-78). In general, the purpose of such a charge is to recover costs incurred by the utility as a result of its obligation to serve, but stranded as a result of a customer's service termination. HECO Companies' Response to PUC-IR-27; see Response to CA-SOP-IR-23.

C. TIME-OF-USE RATES

1. COM's Proposal

COM proposes that the load factor block rates in Schedules P and J be replaced with time-of-use ("TOU") rates. COM attempts to tie its proposal to this proceeding, because TOU rates would encourage DG users to use power sparingly at peaks and do maintenance in off peak periods. COM T-2 at 26-29. HREA also supports TOU rates "to further encourage conservation and energy efficiency." HREA RT-1 at 13.

COM's proposal goes beyond the scope of this proceeding. TOU rates are designed to redistribute load away from system-peak times as a form of demand-side management. Such rate design also recognizes that satisfying load during system peak times is more costly as peaker units (with higher operating costs) are placed into operation. TOU rates fall under the more general category of "distributed energy resources" ("DER"). DG facilities also fall under the DER umbrella. As per Commission Order No. 20582, the focus of this docket is specifically on distributed generation. While "[o]ther DER technologies may be addressed in this docket to the extent they raise the same interconnection and policy issues that the distributed generation technologies raise" the issues surrounding TOU rates are significantly different than those surrounding DG development. HECO RT-5A at 20-21. Also, while the HECO Companies generally support the use of TOU rates, they object to the proposal that such rates be made mandatory at this time.

2. <u>HECO Companies' TOU rates</u>

Currently, the HECO Companies have voluntary time-of-use rate riders for commercial customers, and a few TOU rate contracts under such riders.[4]

HECO has been examining the feasibility of time of use rates for residential customers through its pilot residential time-of-use rate program. This is a 3-year program that began in May 2003, and is limited to 200 residential customers. The program was designed to determine the residential customers' response to time-of-use pricing, as well as to determine the potential residential customers' subscription rate to time-of-use rates and the sustainability of such residential participation or subscription to such rate offering. At the time of the rebuttal testimony, HECO reported that the program was currently in progress with a total of 160

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4 HECO presently offers an optional time of use service to certain commercial or industrial customers. HECO's Schedule U offers an optional time-of-use service for commercial or industrial customers with large power loads of at least 300 kw. Large power customers who are served under any of the large power rates (Schedule PS, PP, and PT) may chose to be served under Schedule U. In HECO's 2005 test year rate case HECO is proposing changes to Schedule U. See e.g., Docket No. 04-0113, HECO T-22 (E. Seese) (filed November 12, 2004) at 39-40. HECO RT-5 at 15.

customers, and data collection on the customers' response to time-of-use pricing was continuing.[5] HECO RT-5 at 14.

3. Mandatory Time-of-use Rates

COM has proposed that HECO replace the current declining block rates for Schedules J and P with mandatory time-of-use rates. This proposal is unreasonable, has no substantive basis, could result in uneconomic bypass. In addition, COM's proposal is contrary to the rate design objectives and philosophy that the HECO Companies have used and which the Commission has approved in all prior rate cases, such as rate continuity, rate stability and equitability, and avoidance of rate shock. HECO RT-5 at 14.

Further, COM failed to provide or offer any substantive justification for its proposal. In fact, mandatory time-of-use rates could have severe economic and costs impacts on customers who cannot respond to time-of-use pricing due to the nature of their business and/or operations. This could result in uneconomic bypass, which in turn could result in rate increases to other ratepayers in the future. HECO RT-5 at 14-15, 18.

Moreover, the HECO Companies have been offering various forms of time-of-use rates, referred to as load management riders, to commercial and industrial customers on an optional basis since 1981. These load management riders include Rider T, Rider M, and Rider I. In addition, a stand alone time-of-use rate schedule for large customers, Schedule U, was implemented beginning in 1991. The availability of the HECO Companies' various time-of-use rates, alongside the current Schedules J and P, offer customers choice and flexibility to select the rate form that provides them with the best economic incentives for their energy efficiency efforts

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5 In HECO's 2005 test year rate case HECO is proposing to offer time-of-use service to residential customers (under Schedule TOU-R) and commercial or industrial customers served under Schedule G or J (under Schedule TOU-C). See e.g., Docket No. 04-0113, HECO T-22 (E. Seese) (filed November 12, 2004) at 53-64.

which meet their energy needs without adversely impacting their business operations. HECO RT-5 at 15-17.

D. INVERTED RATES

1. COM's Proposal

COM asserts that an inverted rate design for the residential class would be less expensive than implementing time-of-use rates for this class. COM also recommends eliminating the current declining block rates for Schedules J and P and replacing them with time-of-use rates. See COM T-1 at 12-13; COM T-2 at 86.

The COM's proposal to implement inverted rates for the residential class is not relevant to the instant DG proceeding and should be rejected by the Commission. Residential customers generally are not the potential users of distribution generation. In addition, COM's proposal for an inverted rate design would not result in better allocation of costs of new DG facilities, because an inverted rate design is a rate structure form, not a cost allocation method. HECO Companies' Response to PUC-IR-32.

2. Inverted Rate Proposal Is Not Cost-Based

The COM's proposal is not cost-based. The COM's inverted rate proposal and proposal to minimize the residential customer charge would further exacerbate the intra-class subsidization within the residential class, as it would further increase the subsidy from the high users to the low users, with larger usage households heavily subsidizing lower usage households. This would result in higher usage customers paying more of the residential fixed costs (i.e., customer-related and demand-related costs) embedded in the energy rates. Currently, the customer charge in the residential rate schedule is already considerably lower than the residential customer cost. HECO RT-5 at 13.

3. Inverted Rate Proposal Is Inconsistent With Commission's Prior Findings

The Commission extensively reviewed the possibility of inverted rates in Docket No. 3874, and rejected this proposal in its Decision and Order No. 6696 issued on June 26, 1981. In that docket, the Commission's decision and order noted that inverted rates result in "assisting lower usage households and penalizing higher usage households." The Commission found that family size was an important factor in determining a family's electric consumption, because larger families were shown to use more electricity, and poverty households tended to have larger household size. HECO Companies' Response to PUC-IR-32; HREA-HECO-RT-5-IR-4.

Further, inverted rates in the form of lifeline rates were extensively reviewed by the Commission in Docket No. 3874, and rejected in its Decision and Order No. 6696 issued on June 26, 1981. The Commission's decision and order in that docket noted that inverted rates result in "assisting lower use households and penalizing higher use households. Family size was shown as an important factor in determining how much electricity a family consumes. Larger families use more electricity and poverty households tend to be larger than other households." See Docket No. 3874, Decision and Order No. 6696 at 132.

4. Time-Of-Use Rates May Be More Appropriate

COM's proposal is not cost-based, perpetuates intra-class subsidization, and would result in the utilities not recovering their fixed costs which in turn could increase rates to all customers in the future. Moreover, time-of-use rates may be more effective in encouraging customers to efficiently manage their loads. Unlike COM's proposed inverted rates, time-of-use rates are cost-based, represent more efficient pricing, and will provide customers with appropriate price signals. HECO RT-5 at 14; Response to HREA-HECO-RT-5-IR-4.

E. PERFORMANCE BASED REGULATION

COM also proposed the implementation of performance-based regulation ("PBR"). See COM T-1 at 13. While a properly structured PBR may have merit, PBR is not relevant to the instant proceeding concerning DG, and COM's proposal should be disregarded.[6] HECO RT-5A at 21; HECO RT-5 at 18.

F. WHEELING RATES FOR COUNTIES

COM recommends that reasonable wheeling rates should be established for county agencies only. COM alleges that county-only wheeling rates would facilitate investments in renewable and energy-efficient DG systems. COM T-1 at 13, 29. However, COM's proposal is beyond the scope of this instant proceeding. Additionally, COM suggested that establishment of its proposed wheeling rate for the transmission of power could be done in the Act 95 RPS investigation proceeding. Tr. (12/8/04) at 225-27 (Kobayashi). Moreover, wheeling is not within the scope of this proceeding, as recognized by the CA. See CA Response to TGC/CA-SOP-IR-3(c). As stated in Order No. 20582, the purpose of this proceeding is to examine the potential benefits and impacts of DG on Hawaii's electric distribution systems and market. As stated in Order No. 20582, the objective of this proceeding is to develop policies and a framework for distributed generation projects deployed in Hawaii. HECO RT-6 at 9-10.

In addition, the County of Maui's county wheeling proposal raises issues associated with wholesale and retail competition. In the Commission's proceeding on electric competition,

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6 The first of a series of PUC-sponsored workshops intended to gather information for use by the PUC to carry out the mandates of Act 95 was held on November 22-23, 2004. Act 95, 2004 Hawaii Session Laws, directs the Commission among other things, to develop and implement ratemaking structures, including but not limited to PBR, which could provide incentives to the utilities to adopt cost-effective renewable resources to meet Hawaii's renewable portfolio standards established in H.R.S. § 269-92. PBR may be best addressed in those PUC-sponsored workshops. HECO RT-5 at 18.

Decision and Order No. 20584, issued in Docket No. 96-0493, the Commission stated that "at best, implementation of retail access would be premature ... projections of any potential benefits of restructuring Hawaii's electric industry are too speculative and it has not been sufficiently demonstrated that all consumers in Hawaii would continue to receive adequate, safe, reliable, and efficient energy services at fair and reasonable prices under a restructured market at this time." Introduction of wheeling raises significant policy issues, which cannot be adequately addressed in the context of only MECO and the County of Maui, as suggested by the County of Maui. The implications of such a proposal would have to be clearly examined and understood, including the implications for the electrical system and equipment, impacts on all customers, as well as impacts to system reliability. HECO RT-6 at 10. For example, KIUC believes that the lost revenues due to intracounty wheeling could be significant. Tr. (12/8/04) at 243 (Friedman).

Further, the COM proposal is completely one-sided, to its benefit, and raises substantial policy issues which cannot be adequately addressed in the context of MECO and the County of Maui, as suggested by COM. The implications of such a proposal should/must be clearly examined and understood, including implications for the electrical system and equipment, impacts on customers, and the impact on the reliability of the system. HECO RT-6 at 10.

CERTIFICATE OF SERVICE

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

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