HREA-HECO-IR-1

(Planning: Issue 1). Referencing page 1 of HECO's SOP, why should DG be only price competitive in the short-term and not also in the long-term, and what fuel does HECO consider to be sustainable in the long-term?

<u>HECO Response:</u>

HECO's SOP identified seven factors for a form of DG to be feasible and viable for Hawaii. These factors collectively provide the motivation for both the DG developer and customer to pursue a DG project. The third factor, economically viable, addresses the requirement that a project be price competitive in the long-term when compared against other options.

As described in HECO's SOP, non-renewable DG technologies can use a variety of fuels including diesel, propane, and synthetic natural gas. These would be the most logical fuel choices for Hawaii DG over the long term due to their availability and relative cost.

The term "economically viable" takes into account longer term considerations. The term "price competitive in the short-term" refers to the tendency of purchasers to look at up front cost and pay back periods in determining whether to make investments, even though more costly investments may tend to be more cost-effective in the long-term.

HREA-HECO-IR-2

(Planning: Issue 1). Referencing page 2, has HECO conducted any studies to compare the emissions per MWH of Internal Combustion Engines (ICEs) used as DG with conventional utility generators? If so, what were the results of the study?

<u>HECO Response:</u>

No, HECO has not conducted any such studies.

HREA-HECO-IR-3

(Planning: Issue 1). On page 6, HECO states: "In order for DG to be accepted in Hawaii, it must be highly efficient (such as CHP systems) and the application must be large enough for a reasonable economy of scale." Is this conclusion based on HECO's estimate of what it would cost the Company to install, own and operate fossil CHP?

HECO Response:

The conclusion that the DG application must be large enough for a reasonable economy of scale applies not only to the Companies but similarly to third-party DG developers.

HREA-HECO-IR-4

(Planning: Issue 2). Referencing page 7, does HREA understand correctly that application (4) would be for a CHP that would off-set a portion up to all of the customer's load, whereas application (7) would be the same as (4), but with the option of exporting electricity to the grid?

HECO Response:

No, application (7) customer-sited DG operating in parallel with the utility grid applies to DG configurations without use of the unit's waste heat. Export of electricity to the utility grid is not intended in this configuration.

HREA-HECO-IR-5

(Planning: Issue 2). Referencing page 8 (second full paragraph), in the case of utility ownership of CHP, to whom would the CHP systems be cost-effective? What does cost-effective mean in this case? Also, does the phrase "does not burden non-participating customers" mean that there would be no rate impacts?

<u>HECO Response:</u>

The Companies' SOP states, "The Companies intend to offer CHP systems to customers in circumstances where utility-ownership of such system is cost-effective and does not burden non-participating customers." The factors taken into consideration in making this analysis are the qualitative factors included in the analyses done for the CHP Program application, and the qualitative considerations listed in the application. The phrase "does not burden non-participating customers" generally means that rate impacts over time on non-participating customers should be not greater than those of the alternative course of action (allowing only third-party CHP; attempting to address load growth central station generation, but not utility owned CHP).

HREA-HECO-IR-6

(Planning: Issue 2). Referencing page 10 (first bullet in the first full paragraph), how would the "interests of all customers be taken into consideration?"

HECO Response:

The interests of all customers are taken into consideration primarily by structuring the program of installing utility-owned CHP systems so that non-participating customers are not burdened. If the electric utility is allowed to participate in the CHP market as a regulated entity, the Commission must approve the Companies' Schedule CHP tariff filing, and/or individual CHP Rule 4 project filings, and the Commission, with input from the Consumer Advocate, has the authority to regulate the Companies to ensure that the interests of all customers are taken into consideration.

HREA-HECO-IR-7

(Planning: Issue 2). Referencing page 11, regarding HECO's claim that "utility participation in the DG/CHP market can help to create a bigger DG/CHP market," what is the basis for the statement that "There is broad-based customer support for a utility CHP program?"

<u>HECO Response:</u>

This is addressed in the CHP Program application (pages 19-22). Several large hotel customers requesting CHP system proposals from the Companies were aware of the CHP system technology but were hesitant to accept the additional responsibilities of operation and maintenance of CHP systems. The Companies' expectation that utility participation in the DG/CHP market can help to create a bigger DG/CHP market is due to customers' knowing that the reliability and maintenance of the CHP systems will not be their responsibility but will be performed by the utility.

The Companies are being contacted by hotel, industrial, commercial, hospital, military, and governmental agencies requesting more information on CHP systems or CHP system proposals from the utility. These customer categories represent nearly all of the large power user customer types on the utility systems and is being characterized as "broad-based customer support". All potential CHP system customers are being informed that the CHP system proposals are subject to PUC approval of the CHP Program application, Docket No. 03-0366.

HREA-HECO-IR-8

(Planning: Issue 2). Referencing the last sentence on page 12, HREA does not understand how HECO would not be in the equipment sales business if they were to supply utility-owned DG to customers. Please explain. On the other hand, if HECO really wanted to facilitate customer choice and assist customers in making decisions regarding DG, would not it be better for all customers if HECO were to encourage DG via a Demand-Side Management (DSM) program (s), such as the highly-successful Residential Efficient Water Heating (REWH) program? If not, why not?

HECO Response:

The Companies would not be sellers of DG or CHP equipment. The Companies would be purchasers of such equipment, and would continue to own, operate and maintain the equipment. The Companies would be sellers of electricity (and thermal energy).

The DSM program model is not appropriate for the Companies' proposed CHP Program. One reason for the Companies' involvement is to offer customers the option to not have to own, operate and maintain the CHP systems. DG technologies are significantly more complicated than the type of equipment covered in the Companies' DSM programs. Specialized training, monitoring, control, and maintenance are required for the successful and reliable operation of CHP systems. The Companies offer qualifying CHP customers the savings from a CHP system without the need for them to hire or train personnel for these specialized tasks.

HREA-HECO-IR-9

(Planning: Issue 3). Referencing the last paragraph on page 14, please explain why HECO is against using customer-sited emergency generation in parallel with the utility grid (i.e., application 7 as noted previously)?

HECO Response:

HECO has not stated that it "is against using customer-sited emergency generation in parallel with the utility grid . . . ." The Companies has stated that they do not intend to offer customer-sited generation for power purposes only as a utility service. This application does not involve the use of customer-sited emergency generation in parallel with the utility grid. Customer-sited emergency generation is not included in application (7), which involves the use the customer-sited generation for power purposes only (as opposed to customer-sited CHP systems, which supply both electrical energy and waste heat for use at the customer site). Customer-sited emergency generation is referred to in application (1).

As noted on page 13, some utilities provide customer-sited emergency generation as a utility service under tariff, with or without the right to use the emergency generators for peaking purposes when there is a capacity shortage, but the Companies do not currently anticipate providing such a service. There a number of issues associated with using customer-sited emergency generation (whether provided by the Companies or not) to satisfy system peaking needs:

a. The air permit obtained by customers to operate their emergency generators may not permit operation in parallel to the grid, i.e., the units may be permitted to operate only for testing or to serve the customers' internal loads only in the event of an emergency.

b. The air permit may allow the unit to operate for only a very limited number of hours for testing and bona fide emergencies only.

c. 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 for more than testing and emergencies. Their objections may be based on noise, emissions and increased truck traffic due to additional fuel deliveries.

d. HECO 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.

e. HECO may not have 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.

HREA-HECO-IR-10

(Planning: Issue 3). Referencing the first paragraph on page 15, HECO refers to the utility's role to develop and enforce interconnection standards, which are reviewed and approved by the PUC. Does HECO support collaborative development of interconnection standards with industry? If not, why not?

HECO Response:

HECO's Rule 14.H interconnection standards, approved by the Commission in Decision and Order No. 20056, filed March 6, 2003, Docket No. 02-0051, included modifications to the Companies' initially proposed interconnection standards based on comments received from the Consumer Advocate and the Commission. The Rule 14.H interconnection standards were also developed based on the then draft IEEE 1547 interconnection standards. HECO does not believe that it is necessary to "reinvent the wheel" with the "collaborative development of interconnection standards with industry". HECO is not aware of any issues and/or proposed revisions raised by the parties to this proceeding with respect to its Rule 14.H interconnection standards. See HECO's Preliminary SOP, Exhibit A, pages 28-29. See also response to HREA-HECO-IR-10.

HREA-HECO-IR-11

(Planning: Issue 3). Referencing the second paragraph on page 15, please clarify "the utility's role to design and obtain approval for utility tariff provisions that ensure that utility customers will not be unduly burdened by the provision of utility back-up service to customers with customer-sited CHP systems or DG."

HECO Response:

The Companies will participate in Commission proceedings to set fair and equitable rates and/or tariff provisions to reasonably recover the costs of providing standby service from standby customers imposing such costs.

HREA-HECO-IR-12

(Impact: Issue 4). On page 16, HECO discusses the impacts of DG on Hawaii's transmission and distribution ("T&D"). Would it be correct to view DG as "negative loads?" Therefore, assuming that a DG is to be installed per an agreed-upon interconnection standard, would it be correct to conclude that the load-carrying requirements on the line feeding the DG customer would be reduced? Please clarify then why assessing the "impact of DG on Hawaii's transmission and distribution ("T&D") is complex and requires detailed studies of on a case-by-case basis?"

<u>HECO Response:</u>

a. In considering the impacts of distributed generators operating in parallel with a utility's transmission and distribution ("T&D") <u>system</u>, which is the subject of Issue 4, it would not be correct to view DG simply as "negative loads". That is the reason interconnection standards and interconnection agreements are required for DG, as was addressed in Docket No. 02-0051 (consolidated). It would also be incorrect to view DG as "negative loads" from a T&D capacity planning standpoint, since the impact of DG on customer loads is not continuous.

b. T&D capacity planning generally is based on peak loads under various contingency conditions. Therefore, it cannot simply be concluded that the load-carrying requirements on the line feeding the DG customer would be reduced. The extent to which a utility could consider the load-carrying requirements of lines to be reduced as a result of the installation of <u>multiple</u> DG units would depend on factors such as the relative sizes of the DG units, the reliability characteristics (e.g., forced outage rates) of the DG units, and the ability of the utility to coordinate scheduled maintenance or to require that scheduled maintenance takes place during off-peak periods (as a result of contractual agreements with enforcement provisions). The load-carrying requirements would not be reduced to the extent that the utility still has to plan to carry the entire load when the DG is off-line.

c. Some of the factors that contribute to the complexity are identified on page 19 of the Preliminary SOP, which addresses Issue 5. The studies that may be required are identified in the interconnection standards included in Tariff Rule 14.H. (Rule 14.H covers interconnection of distributed generators that do not export power to the utility grid, and interconnection of DG requesting to export power to the utility could require additional technical study.) As an example of one such factor, there is increased risk of voltage regulation problems, adverse interactions with the utility's protection system, and unintended islanding that could occur as the penetration of distributed generating capacity increases on a utility distribution feeder. Therefore, when the penetration of DG for a distribution feeder exceeds 10% of the peak annual KVA load of the feeder, the interconnection standards provide that a technical study to examine the risk of voltage regulation problems, protection malfunction from reverse power flow and unintended islanding may be required.

In a February 2002 technical update from EPRI entitled "Integrating Distributed Generation into the Electric Distribution System", the update noted that (1) the electric T&D system has been traditionally designed to operate as a "one-way" power flow system, with centralized plants feeding at a variety of power usage points, and (2) the primary interconnection issues that must be addressed relate to system protection, personnel safety and voltage quality.

HREA-HECO-IR-13

(Impact: Issue 5). On pages 18 to 19, HECO discusses DG interconnection requirements and the HECO interconnection standard for DG (Rule 14 H). HREA believes that this rule may need to be revised on account of the DG Docket. Would HECO support a collaborative effort to discuss and prepare revisions to Rule 14 H?

HECO Response:

HREA has not provided support for its alleged belief "that Rule 14.H may need to be revised on account of the DG Docket", or any reason for the Companies to believe that Rule 14.H may need to be revised on account of this docket. See also response to HREA-HECO-IR-10.

HREA-HECO-IR-14

(Impact: Issue 5). On page 19 (discussion of adverse impacts on system reliability, first bullet), HECO states that "all DG units must be backed up by the grid." Would HECO agree that this statement would not be true if DG customers did not require back-up from the utility? If not, why not?

HECO Response:

This statement would not be applicable if a customer is able to withstand the loss of its DG power through means other than utility grid backup, and the load served by its DG is isolated from the grid. (If the DG is operating in parallel with the grid, it is being backed up by the grid.)

HREA-HECO-IR-15

(Impact: Issue 5). On page 19 (discussion of adverse impacts on system reliability, second bullet), would HECO still have this concern if the DG interconnect agreement required the DG owner/operator to: (1) provide and update HECO with the operational schedule of the DG facility, and (2) provide a data line to HECO for monitoring the operation of the DG facility? If this is not sufficient to address HECO's concerns, what other requirements does HECO think would be appropriate?

<u>HECO Response:</u>

Yes, HECO would still have some concerns. Providing HECO with an operational schedule and a data line for monitoring the operation of the DG facility helps to address only certain operational aspects of controlling operations and maintenance quality of the DG installations. They do not address the maintenance aspects of the DG installations. The following requirements from the maintenance perspective, though not an exhaustive list, would help to mitigate HECO's concerns:

- Provide to HECO the DG manufacturer's recommended maintenance practices and procedures for the type of unit installed.
- Demonstrate to HECO that the DG manufacturer's recommended maintenance practices and procedures for the type of unit installed have been and will be diligently followed.
- Provide to HECO evidence that an adequate fuel supply and fuel storage exists.
- Provide a utility compatible monitoring and control system to allow HECO dispatchability of the DG installation to allow for responsiveness to utility system conditions.

In addition, HECO would require that the interconnection of the DG to the utility grid be in compliance with HECO's Rule 14H interconnection standards to ensure safe and reliable operation of the DG unit.

HREA-HECO-IR-16

(Impact: Issue 6). Referencing the last sentence on page 22, please provide an example of how "In the case of utility-owned CHP systems, all of these factors can be taken into account so that non-participating customers are not burdened by the offering of such services."

HECO Response:

The Companies' CHP Program, Docket No. 03-0366, filed on October 10, 2003, provided a detailed economic analysis of the utility CHP Program. The Companies' economic analysis, which takes into account all of these factors, showed that the utility's CHP Program was a lower cost alternative when compared against the case without utility CHP. This analysis shows that non-participating customers are not burdened by the utility's CHP Program.

HREA-HECO-IR-17

(Impact: Issue 7). On pages 23 to 24, HECO lists a number of "positive and negative DG externalities". Given that externalities are those costs and benefits that are not presently accounted for in our current energy transactions, why are the first and third bullets (on the positive externalities list) externalities? Specifically, in bullets 1 and 3, the DG owner would be paying for the described benefits, whereas the avoidance of fossil emissions (bullet 2) are externalities that are being accounted for only in part, e.g., emissions fees on SOx and NOx, but not CO2.

HECO Response:

The first bullet on the list of positive externalities refers to the ability to meet specific needs of an energy user using DG. The third bullet on the list of positive externalities refers to the ability to switch to new technologies due to lower incremental cost of DG.

External benefits are generally described as the positive impacts on the activities of entities outside the utility and its ratepayers. For the first and third bullets in on page 23 and 24 of HECO's Preliminary Statement of Position, HECO's is merely pointing out that the benefits from DG of meeting specific customer needs and the smaller incremental cost could be outside the utility and its ratepayers.

HREA-HECO-IR-18

(Impact: Issue 8). Referencing the first paragraph on page 26, HECO states that "forecasted load growth is much higher than can be met with distributed generation alone, given the relatively small scale of distributed generation systems." Does HREA understand correctly that this statement is based on a HECO study of the DG market? If so, please provide a copy of the market study to HREA?

HECO Response:

Please refer to HECO's response to CA-SOP-IR-22, part b.

HREA-HECO-IR-19

(Implementation: Issue 10). In the next to last paragraph on page 31, HECO discusses the impacts of DG on the existing cost-of-service for residential vs. other classes, e.g., large power and commercial. Currently, HREA understands that the rate-of-return on residential accounts is less than that for commercial accounts. HECO states that: "This benefits the residential class, but only as long as large commercial customers do not leave the system because of rates that are higher due to the subsidy." Is it correct to assume that commercial DG customers would "leave the system?" Would not commercial DG customers remain interconnected with the grid?

HECO Response:

The statement is based on a large customer leaving the system either partially or completely.

Even if the large customer remains interconnected to the grid after installing a DG the reduced utility sales would diminish the benefit for the residential class.

HREA-HECO-IR-20

(Implementation: Issue 11). On page 33, HECO states that no changes are needed to the IRP process. Would HECO agree that implementation of DG would benefit from the utility specification in IRP of areas and amounts of DG that would provide positive impacts to the utility system, e.g., to reduce line losses, off-set new T&D upgrades and defer generation?

HECO Response:

The ability of CHP systems to avoid central station generation costs (including line losses and generation deferral benefits) can be taken into account, generally in the manner employed in the quantitative analyses included in Docket No. 03-0366, without targeting CHP and DG to specific areas. The difficulties involved in attempting to target "areas and amounts of DG that would...off-set new T&G upgrades" has been explained in HECO's advisory group process for its third IRP Plan. See also HECO's response to HREA-HECO-IR-12.

HREA-HECO-IR-21

(Implementation: Issue 13). Referencing page 35, HREA cannot support the Companies' proposed CHP program and CHP tariff, in part, as it would perpetuate increased utility rates when the utility makes new investments and continues to pass through fuel costs. Would it not be better for the ratepayer, if DG investments and fuel purchases were not rate-based?

HECO Response:

No. Unfortunately, it does not appear that HREA understands ratemaking or the impact of DG on utility rates. If a utility does a CHP system project instead of a third-party, the utility incurs costs (in the form of the CHP system investment and O&M expenses for the system), but retains revenues that would otherwise have been lost. By doing cost-effective CHP system projects, the net effect is to benefit non-participating utility customers (i.e., customers that do not install CHP systems). By increasing the number of CHP systems installed, the utility can also avoid (i.e., defer) investment in central station generation (and avoid the variable expenses of producing and delivering the energy avoided by the CHP systems). As is shown in the CHP Application, the net effect is to benefit non-participating utility customers. (In addition, it should be noted that fuel expenses are not "rate based". The rate base refers to the utility's net investment in utility assets. With the exception of fuel inventory, fuel in an expense item, not a rate base item.)