PUC-IR-3 **(All Parties)**

Ref: HECO SOP, Exhibit A at 4; HREA-HECO-IR-9.

These references address the potential for an increased reliability risk as a result of the implementation of competitive bidding and purchased power. Please elaborate on the solutions to this potential problem, and specifically identify potential mitigating factors that can be incorporated into the competitive bid process.

HECO Response:

Exhibit A to the HECO Companies' SOP, at pages 4 through 8, identify the increased risks associated with the implementation of competitive bidding and the addition of IPPs on the utility system, along with potential strategies to mitigate to some extent some of these risks and the challenges and limitations of these strategies both in terms of practical implementation and effectiveness. For example, as noted on page 4 of Exhibit A to the SOP, the potential for project failure during the development process and contract default on the part of independent power producers creates the potential for reliability risk, particularly if there are no readily available alternatives to meet customer requirements if a project fails or defaults. More stringent contract provisions such as higher security levels, clearly defined milestone schedules and associated damages if milestones are not adhered to, and other financial disincentives have been applied as solutions to mitigate this problem in other jursidictions. On the Mainland, access to security allows the utility to replace the contracted power through market purchases and the application of liquidated damages to make the utility's customers whole.

However, in Hawaii, even with stringent contract provisions and penalties for failure to perform under the contract, there is still the potential for an IPP to default on its obligation and incur the penalties. If the IPP cancels the project, the costs to customers could be much greater than the contract penalties alone if system reliability is jeopardized. At the end of the day, customers need electricity and contractual penalties paid by an IPP to the utility cannot replicate that. While liquidated damages could be included in the contract, such provisions may discourage bidders or lead to higher priced bids to compensate for the risk.

In addition to more stringent contract provisions, HECO has suggested that parallel planning may be another option to mitigate risk, particularly given the isolated nature of our island utility systems. Under this option, HECO could continue to proceed with a self-build option until it is highly certain that the awarded project will meet its commercial operation date. The costs for such parallel planning would be recovered by HECO, and would need to be considered as part of the overall cost to provide reliable power to customers. Such increase in the overall cost of power development may offset any hoped for cost savings benefit that competitive bidding is perceived to provide.

Another possible option to potentially mitigate the reliability risk to customers is to allow HECO the option to buy the awarded bidders project if the bidder defaults on the contract. However, some of the practical challenges with this option include that the entity financing the project normally has first lien rights on the asset in case of default, relegating the purchasing utility to a lesser second lien position on the project.

The cost, practicality and potential unintended consequences of any candidate mitigation measure must be examined much more closely in the context of the small, isolated utility systems that exist in Hawaii before firm conclusions and recommendations can be reached on their effectiveness in any potential competitive bidding process.

PUC-IR-4 **(HECO)**

Ref: HREA-HECO-IR-9(2)at 2.

a. The first load-shedding incident involving AES appears to have been initiated by the loss of the Waiau-Koolau #1 line, and the subsequent loss of Waiau #7. Is this correct?

b. Was AES responsible for the loss of the Waiau-Koolau #1, or the loss of Waiau #7?

c. If the AES units had been HECO-owned and operated, how might this load-shedding incident have changed?

d. HECO notes three (3) load-shedding incidents involving AES since 1992. Does HECO consider this frequency substandard or indicative of a problem that requires resolution?

e. In general, how does this frequency (i.e., for AES) compare to what HECO has experienced with its own comparable facilities during the same period?

<u>HECO Response:</u>

a. The events that preceded the AES trip were the loss of the Waiau-Koolau #1 138 kV line, the loss of Waiau 7 and the loss of Kahe 5. As described in the response to HREA-HECO-IR-9, the AES unit tripped on the loss of control air, approximately 7 minutes after the Kahe 5 trip.

b. The response to HREA-HECO-IR-9 indicates that the inclement weather caused the Waiau-Koolau #1 138 kV line to trip. Waiau 7 tripped as a result of the Waiau – Koolau #1 138 kV line trip. (The issue with generating units is how they respond to or during a system disturbance, such as a transmission line outage or the trip of another generating unit.)

c. It would be speculative to draw conclusions as to how the incident may have differed if HECO owned and operated the AES unit.

d. While HECO prefers not to have any load-shedding incidents, three (3) AES-related occurrences since 1992 do not appear to be substandard. However, because the AES unit is the largest on the system, its loss has a greater impact on the frequency response and can result in a load shedding incident. HECO is diligently working with AES to maintain an acceptable performance record as the unit continues to age.

e. HECO does not own any generating facilities that are directly comparable to AES, which is a 180 MW Atmospheric Fluidized Bed Combustion (AFBC) Coal unit that was placed in service in 1992. The newest and largest HECO units are Kahe 5 and Kahe 6. Kahe 5 is approximately 135 MW (net), and was placed in service in 1974, approximately 18 years prior to AES. Kahe 6 is approximately 134 MW (net), and was placed in service in 1981, approximately 11 years before AES. There were no Kahe 5 or Kahe 6 load shedding trips during the period from 1992 to present.

PUC-IR-5 **HECO)**

Ref: HREA-HECO-IR-17.

Does HECO possess any operational data that demonstrates that existing Independent Power Producer (IPP) facilities and utility-owned facilities of comparable age and type in Hawaii have differing levels of reliability?

HECO Response:

The most significant firm power IPPs for the HECO utilities are as follows:

- AES Hawaii: 180 MW AFBC Coal, In-Service 1992 on Oahu
- Kalaeloa Partners L.P.: 180 MW DTCC using LSFO, In-Service 1991 on Oahu (w/additional 29 MW pending)
- Hamakua Energy Partners L.P.: 60 MW DTCC using Naptha, In-Service 2000 on Hawaii
- H-POWER: 46 MW MSW, In-Service 1990 on Oahu
- Puna Geothermal Venture: 30 MW Geothermal, In-Service 1990 on Hawaii
- HC&S: Approximately 16 MW exported to MECO; combination of steam generators and hydroelectric plants of various ages.

The HECO utilities do not own any AFBC Coal, Municipal Solid Waste, or Geothermal facilities. Therefore, HECO is unable to demonstrate the requested comparison for the AES Hawaii, H-POWER, or PGV projects.

However, the HECO utilities currently operate a nominal 57 MW (net) DTCC, which was placed in service in 1993. This unit is located at the Maalaea Generating Station on Maui, and while it is older than the Hamakua Energy Partners (HEP) facility, it is based on LM2500 combustion turbines (the same model CTs that HEP operates), with heat recovery steam generators, and a steam turbine.

The HEP facility has experienced many more frequent unit trips than the comparable Maalaea unit, as illustrated in the table below:

Unit Trips:	**HEP LM2500 (CT, CT, or ST)**	**Maalaea LM2500 DTCC (CT, CT, or ST)**
2001	22	4
2002	6	4
2003	8	2
2004	15	6
2001 - 2004	**51**	**16**

PUC-IR-7 **(HECO)**

Ref: HECO SOP, Exhibit A at 5, states:

> In some cases, developers have been known to walk away from partially or nearly completed projects simply because the cost of completing the project and operating the facility were not economically viable.

a. Please identify the cases referred to.

b. For each case identified, please indicate whether the power purchase agreements imposed penalties for abandoning the project. If penalties were imposed, were they paid and what were the amounts?

c. Please comment on the effectiveness of these penalty clauses. Is it possible to design penalty clauses that effectively discourage this type of behavior? Please explain.

HECO Response:

a. Please see HECO's response to CA-HECO-IR-15. HECO's response to CA-HECO-IR-15 identifies several recent cases in which a project developer walked away from a partially or nearly completed project. In one case, a major IPP declared bankruptcy. In the other cases that were mentioned, the IPP basically "turned over" their projects to the financial institutions that held the debt on such projects.

b. The projects identified were all merchant plants. HECO is not certain if these plants had contracted any of their capacity on a long-term basis via a power purchase agreement or whether the PPA imposed penalties for abandoning the project.

c. Contract provisions such as high security requirements, stringent liquidated damages provisions and significant penalties for missing key milestones are contract options that could be used for discouraging this type of behavior. However, in an isolated island market such as Hawaii, where the utility does not have access to a broad power market to acquire replacement energy resources, the cost to customers for failure of the IPP to provide reliable service may greatly exceed these potential penalties and such stringent penalties may discourage bidders from competing in the solicitation process.

PUC-IR-8 **(HECO)**

Ref: HECO SOP, Exhibit A at 5-6.

Six (6) examples are provided of how a utility's operating flexibility can be constrained by IPPs. For each one, please discuss to what extent, if any, contractual provisions can be designed to limit or eliminate these constraints. Provide specific contractual language where feasible.

HECO Response:

1. An IPP may be reluctant to increase its expenses in order to hasten a return from a planned maintenance outage to accommodate the utility's need for capacity at a particular time.

Response: Generally, the pricing formula in the power purchase agreement establishes the amount of revenues the IPP will receive. If the IPP's actual costs are higher than expected, the IPP absorbs the additional costs. Likewise, if the cost is lower than expected, the IPP earns additional revenues. Since IPPs cannot pass additional expenses through the contract, it will be reluctant to incur additional costs to meet the utility's need for capacity. A common contract provision that may help to limit this problem is the requirement that an IPP coordinate its planned maintenance with the utility beforehand. This provision could serve to limit the constraint if the utility can know with some certainty well in advance if it needs the capacity at a certain time, which is a fairly narrow case. Unfortunately, this provision is unlikely to provide much help in the more common situation where the utility's need for capacity is due to rapidly changing conditions, such as severe whether impacts or other operational or maintenance constraints on the system, and the IPP's planned maintenance schedule has long been coordinated under the subject contract provision. Please see attached pages 6-8 as an example of such a provision from a Hydro-Quebec contract.

2. An IPP that is capable of providing more capacity than it is obligated to under the terms of the PPA may limit the output of its facilities to the grid, even though the utility may have a need for the capacity at a particular time.

Response: Under a traditional PPA, the utility pays for capacity up to the level in the contract. This is designed for preventing an IPP from "putting more capacity" to the utility if the contract price is favorable even if the utility does not need capacity. Most contracts will agree to pay for additional energy at an avoided energy rate or a pre-established price but not capacity. An IPP unit may often have the capability to provide more capacity to the utility grid than its contractual obligations under a PPA on a temporary basis during system emergency conditions, such as the sudden loss of other generating units tied to the grid. However, the IPP may not be willing to provide that capacity because it is not "contracted" for, even with the real time knowledge that service to the utility's customers is being impacted, for example, due to load shedding or power quality excursions. In contrast, the utility has exclusive control of its own units and will "push" its generators to their design and permitted capabilities to maintain reliable service to its customers under such circumstances.

3. IPPs are dispatched based on PPA pricing provisions, which often contain pricing curves. If it turns out that the pricing curves do not actually track the IPPs costs, then the IPPs will seek to be dispatched (and will exercise their rights under the PPA) so as to maximize their profitability (taking into account differences between their prices and costs), not to minimize the utility's costs.

Response: The utility can seek to negotiate the right to dispatch the IPP as it deems appropriate, within a range of minimum and maximum loads, to meet the utility's needs. Thus, if the price of energy dispatched at a particular load level as defined by the negotiated pricing curves is not economic to the IPP, the IPP may not request to be dispatched at a more economic load level. The utility right to dispatch is a major issue in negotiating a PPA.

4. An IPP may refuse to operate during certain periods of the week because it is more economical to pay a penalty according to the PPA for being unavailable than to operate.

Response: Many contracts do not accurately reflect the value of power during peak and off-peak periods and instead establish the payment and availability provisions based on equivalent monthly or annual values. Central & Southwest Services attempted to tie the payments to the IPP based on the value of power during peak and off-peak periods. CSW included a seasonal adjustment factor in its capacity payment formula whereby the IPP was paid more for capacity during the peak period than during the off-peak period. As an example, assume the capacity price is $10/Kw-month and the contract capacity is 10 MW or 10,000 Kw. Under most contracts, if the IPP met its availability provisions, it would be paid $100,000 for that month in capacity payments and $1,200,000 for the year. Under CSW's methodology, a seasonal adjustment of as much as 2.1 would be applied as a multiplier to determine capacity payments for a particular month. While the IPP would be paid the same $1,200,000 per year, the distribution of the payment stream could vary. Thus, the IPP could be paid as much as $210,000 during the each peak month and a lower amount during the off-peak months. Of course, if the units' actual availability is less than the target availability included in the contract, the capacity price would be lowered and as a result monthly payments would be decreased. If availability was lower during the peak months, the reduction in payments would be magnified by the value of the multiplier. Thus, such an availability provision penalizes the IPP more for failure to meet the guaranteed availability during peak periods. The incentive would therefore be designed to encourage the IPP to be available at the guaranteed level during the peak period based on the contract.

A copy of the availability provision from the CSW companies contract is attached as pages 9-12.

5. An IPP may be experiencing frequent forced outages, which may result in service interruptions to utility customers. Yet the utility only has a limited amount of latitude under most PPAs to require evaluations of the IPPs power plant configuration, and to design and specify improvements to reduce the number of forced outages.

Response: If a facility is experiencing frequent forced outages, the immediate impact may be that the IPP achieves lower levels of availability than guaranteed in the contract and therefore could experience a reduction in its capacity payment until the problem is corrected. In some contracts, if the IPP fails to maintain a certain minimum equivalent availability factor (e.g., 60% on a rolling 12 month basis), this would trigger an event of default and the buyer can terminate the contract. As an example, two pages from Carolina Power & Light's Standard Contract (pages 19-20) from its April 1997 RFP are attached as pages 14-15.

In addition, there are generally provisions in the contract that if the seller cannot meet its contract capacity levels, there are provisions in the contract to lower the level of contract capacity as the basis for payment or for the buyer to terminate the contract.

While a typical provision in a Power Purchase Agreement is that the IPP must operate the plant consistent with "Good Utility Practice", the utility does not have much latitude under the contract to require evaluations of the IPPs power plant configuration and to design and specify improvements to reduce the number of forced outages unless the IPP defaults.

Another provision in the Carolina Power & Light Standard Contract (pages 36-37) attached as pages 17-18, addresses the forced outage issue. Under this provision the IPP is required to report to the utility any forced outages. After the first failure to report, subsequent failures are subject to penalties.

6. Many IPP units are designed, built, owned and operated by mainland or foreign-based corporations who may not fully understand the intricacies of operating small, isolated, non-interconnected island grids. Often they do not comprehend the relative impact of their generation on these smaller isolated grids, and may resist operating under system conditions such as low frequency, low voltage, high frequency or high voltage under which utility units have to operate under system contingency conditions. The result is a higher potential for grid instability.

Response: The power purchase contracts that have been negotiated in the past were mostly for conventional, fossil fuel fired generating units. These contracts have standards for delivery of power including voltage, frequency, and reactive standards, and also standards for the design of the generators. Recent power purchase contracts have been negotiated with IPPs that employ non-fossil fuel fired generating units, such as wind farms. In recognition of the inherent characteristics of these kinds of generation, recent power purchase contracts also include standards for the IPP to ride through excursions in system voltage and frequency, as well as standards for ramp rates and power fluctuation rates. The standards for power delivery, power quality, and design of generators in power purchase contracts seek to mitigate the IPP's impact on grid stability.

Note to Supplier:

This document is a translation of the Standard contract (*Contrat-type*) which, in accordance with section 4.23 of the Call for tenders document, will be written and signed in the French language only. This document is provided to the Supplier to facilitate reading and may not be used to interpret the *Contrat-type*.

ELECTRICITY SUPPLY CONTRACT

(STANDARD CONTRACT – NEW POWER PLANT – BASELOAD)
CALL FOR TENDERS A/O 2002-01

BETWEEN

SUPPLIER

AND

HYDRO-QUÉBEC DISTRIBUTION

DATE: _______________

(Translation only)

21 CERTIFICATE OF COMPLIANCE

The **Supplier** shall supply the **Distributor**, at the **Supplier**'s expense, prior to the *commencement date of delivery* and within the time period specified in section 25 of the *contract*, with a certificate approved by the *lender*'s engineering firm or a firm approved by the **Distributor**, confirming that generation of electricity at least equivalent to the *contract capacity* was maintained during a period of one hundred (100) consecutive hours, without interruption, taking into account the power curves of the *power plant*'s generating units.

22 PERMITS AND AUTHORIZATIONS

The **Supplier** shall obtain and keep in force all permits and authorizations required by the laws, regulations and standards in effect in Québec and Canada for the construction of its *power plant* and for its operation at generation levels that conform to the requirements of the *contract*.

The **Supplier** also undertakes to perform all the work which may be required during the course of the *contract* resulting from changes to laws, regulations and standards.

Without limiting the generality of the foregoing, the **Supplier** shall obtain all rights pertaining to atmospheric emissions which may be required by the competent authorities.

All costs related to the foregoing shall be borne by the **Supplier**.

23 MAINTENANCE SCHEDULE AND UNAVAILABILITY LOG

The **Supplier** shall, at its own expense, perform maintenance work on its *power plant* for the entire duration of the *contract*.

The **Supplier** shall prepare a typical annual schedule for current maintenance work and a schedule for major work to be done on the *power plant*. The typical annual maintenance schedule and major work schedule, the content of which must be substantially in keeping with the recommendations of the various equipment manufacturers, shall be submitted to the **Distributor** no later than thirty (30) days prior to the *commencement date of delivery*.

The **Supplier** shall coordinate its maintenance schedule with the **Distributor** and submit a maintenance schedule to the **Distributor** for each *contract year* for approval. The rules regarding maintenance scheduling shall be drawn up in writing by the Parties' representatives designated in section 40. However, no interruptions in electricity deliveries for maintenance purposes shall be scheduled during the months of November, December, January, February and March, unless the **Distributor** authorizes the **Supplier** to do so.

The **Supplier** shall keep a maintenance log and another logbook to record the times when the *power plant* is unavailable. Said logbook shall indicate, for each unavailability, the cause, duration, with the start and end dates, the date of restoration of service and any other relevant information.

The **Distributor** shall have access to all such logbooks during *business days* and may obtain a copy of them.

24 ELECTRICAL SUPPLY BY THE DISTRIBUTOR

During the construction phase, for startups, for purposes of maintenance or when the *power plant* is unavailable for any reason whatsoever, if the **Supplier** requires electricity from the **Distributor**, the latter shall sell such electricity to the **Supplier** based on rates and conditions established under Hydro-Québec regulations or decisions rendered by the *Régie* which apply to the **Distributor**'s customers at the time of the supply.

At no time may the **Supplier** resell such electricity to the **Distributor** or to any third parties, in any manner, or use it for the purposes of generating electricity in any manner, either directly or indirectly.

PART VII – COMMENCEMENT OF DELIVERIES

25 *COMMENCEMENT DATE OF DELIVERY*

The *commencement date of delivery* shall be established by the **Supplier**, which shall provide the **Distributor** with prior notice to this effect of at least five (5) *business days*. Prior to giving said notice, the **Supplier** must have fulfilled the following conditions:

a) Submission to the **Distributor** of a typical annual maintenance schedule and major work schedule, as provided for in section 23;

b) Have all the certified copies of permits and authorizations required under section 22;

c) Submission to the **Distributor** of a copy of the contracts and other documents specifying the obligations mentioned in section 26;

AGREEMENT FOR

THE PURCHASE OF RENEWABLE
[SMALL-SCALE /DISTRIBUTED RESOURCES] GENERATION

FROM THE _______________ PROJECT

BY AND BETWEEN

SOUTHWESTERN ELECTRIC POWER COMPANY

AND

____

DATED ______________________, 199_

APPENDIX D

Determination of Contract Pricing

D.1 Capacity Payment

A. Capacity payments shall be calculated pursuant to this Appendix D and shall be made monthly to Seller subject to the terms and conditions of the Agreement.

B. The capacity charge set forth in Schedule 4-1 of the Response Package shall be multiplied by the Net Capability and by the Monthly Availability Adjustment Factor set forth in Section D.2 of this Appendix D.

D.2 Availability Adjustment Factor

A. Availability Adjustment Factor is defined as:

$$AAFM = \frac{EAF \times SAF}{TEAF}$$

where:

AAFM= Monthly Availability Adjustment Factor;

EAF = Equivalent Monthly Availability Factor, as further defined in Subsection D.2 (B), below.

TEAF = Annual Target Equivalent Availability Factor proposed by bidder. Tab 4 of the Response Package.

SAF = Seasonal adjustment factor set forth below for each month of the year.

If the Facility's Equivalent Monthly Availability Factor is higher than the TEAF specified, a monthly premium will be applied. However, payments to the bidder will be capped on a rolling 12 - month historical basis at the sum of the specified 12 - month capacity and fixed O&M price bid set forth in Appendix A.

APPENDIX D (Page 2 of 3)

Determination of Contract Pricing

The Seasonal Adjustment Factors are as follows:

Jan	1.00	July	2.10
Feb	.20	August	2.10
March	.20	Sept.	2.10
April	.20	Oct.	.70
May	.90	Nov.	.20
June	1.40	Dec.	.90

(B) Equivalent Monthly Availability Factor. The Equivalent Monthly Availability factor is determined by the Facility's outages resulting form both its reported outages and its economic dispatch performance, as follows:

$$EAF = \frac{\text{Available Generation in on-peak hours} \times 100}{\text{Maximum Generation}}$$

$$= \frac{AH - (EUNDH + ESDH) \times 100}{PH}$$

AH = The number of hours a unit was in the available state. Available hours is the sum of service hours and reserve shutdown hours, or could be computed from period hours minus unavailable hours.

EUNDH = Equivalent Unit Derated Hours. This represents the available hours during which a derating was in effect, expressed as equivalent hours of full outage at maximum capacity.

ESDH = Equivalent Seasonal Derated Hours. This represents the available hours during which a derating was in effect, expressed as equivalent hours of full outage at maximum capacity.

PH = The number of hours a unit was in the active states provided that the Net Capability shall be set equal to the Net Capability as determined in the most recent Summer or Winter test period, as appropriate to the current month, unless re-established by a more recent test.

APPENDIX D (Page 3 of 3)

Determination of Contract Pricing

D.3 Energy Payments

A. Energy Payments shall be calculated monthly pursuant to this Appendix D and shall be made monthly to Seller according to the terms and conditions of this Agreement.

B. The Energy Payment for each month shall be product of the number of KWH's delivered to Buyer during the preceding month, the Adjusted Energy Rate as determined pursuant to the provisions of Subsection D.3 (D) below, and the on-peak and off-peak multiplier.

C. The on-peak multiplier shall equal 1.2 for deliveries during December, January, February, June, July and August. The off-peak multiplier for all other months shall be .8.

D. Adjusted Energy Rate for Energy Sales by Seller to Buyer.

The Adjusted Energy Rate for all MWH received by Buyer from Seller on or after the Commencement Date of Operation shall be the Energy Price specified on Schedule 4-1 of the Response Package multiplied by the Energy Rate Adjustment Factor set forth in Subsection D.3(E) below.

E. Energy Rate Adjustment Factor for Seller's Non-Production.

The Energy Rate Adjustment Factor shall be unity (the number 1) unless total and/or on-peak and/or off-peak energy production deliveries by Seller to Buyer are less, respectively, than the guaranteed total generation and/or guaranteed on-peak and/or off-peak generation for any rolling 12-month period. In the event of any such shortfall, until any and all such shortfalls are eliminated, the Energy Rate Adjustment Factor shall be the smallest of the fractions calculated over a rolling 12-month period as (i) the ratio of the total production delivery to the guaranteed total generation; (ii) the ratio of the on-peak energy production delivery to the guaranteed on-peak energy generation; and (iii) the ratio of the off-peak energy production delivery to the guaranteed off-peak energy generation.

MODEL POWER PURCHASE AGREEMENT

AGREEMENT FOR THE PURCHASE OF POWER

BETWEEN

CAROLINA POWER AND LIGHT COMPANY

AND

SELLER

DATED ______, 199__

5.7 Regulatory Review

Seller and CP&L agree that this Agreement shall be subject to regulatory review and authority to the extent of the Commission's jurisdiction. Seller and CP&L further agree that if at any time during the term of this Agreement CP&L shall be denied authority by the Commission to recover from its customers all or any part of the payments made or to be made by CP&L to Seller hereunder, CP&L shall have the right to reduce the payments to be made to Seller hereunder to the level allowed to be recovered from such customers by the Commission and to require a refund by Seller of any such payments previously made by CP&L which CP&L is not permitted to recover from its customers or has been ordered to refund to such customers.

5.8 Records

Seller agrees to maintain books and records in accordance with generally accepted accounting principles. CP&L shall have access to all such books and records during normal business hours. All records of Seller pertaining to the operation of the Facility shall be maintained on the premises of the Facility. Seller shall provide CP&L with copies of annual financial reports provided by Seller to the Project Lender.

SECTION 6. DEFAULT AND TERMINATION; SECURITY

6.1 Events of Default and Termination

a. Each of the following events shall constitute a breach by Seller under this Agreement, and shall be considered Events of Default by the Seller unless cured within the timeframe provided in Section 6.1b:

(1) Seller's failure to fund the various Security Funds as required by this Section to the levels and timing specified.

(2) Seller's failure to replenish the various Security Funds as required by this Section.

(3) Seller's failure to make payments due CP&L for liquidated damages pursuant to Section 6.

(4) Seller's failure to meet any Milestone Date or to satisfy all Conditions Precedent and achieve Commercial Operation by the Scheduled Commercial Operation Date.

(5) Seller's assignment of this Agreement or any rights hereunder for the benefit of its creditors, or Seller's dissolution or liquidation.

(6) Seller's assignment of this Agreement or any of its rights or obligations under it, the sale or transfer of voting control of Seller, or Seller's sale or other transfer of its interest or any part thereof in the Facility, without obtaining CP&L's prior written consent.

(7) The filing of a case in bankruptcy or any proceeding under any other insolvency law by or against Seller as debtor or its parent or any other affiliate that could materially impact Seller's ability to perform, provided, however, that Seller shall be given sixty (60) days after such filing by a third party in which to obtain a stay or dismissal prior to this provision constituting an Event of Default.

(8) Seller's failure to make any payment for power as required under Section 3.2.c of this Agreement or any other payment required under this Agreement.

(9) The sale by Seller to a third party, or diversion by Seller for any use, of electrical capacity or energy from the Facility, without the prior express written approval of CP&L.

(10) Seller's failure to maintain at least a sixty (60) percent Equivalent Availability Factor on a rolling twelve (12) month basis.

(11) Seller's failure to deliver any energy or capacity Dispatched pursuant to this Agreement within any consecutive one hundred eighty (180) day period following the Commercial Operation Date.

(12) Seller's abandonment of the development or operation of the Facility for any reason either before or after commencing Commercial Operation and prior to expiration of this Agreement.

(13) Seller's failure to comply with or to operate the Facility in conformity with any material provision of this Agreement.

(14) Any material misrepresentations by Seller.

(15) Seller's attempt to tamper with CP&L's Interconnection Facilities or Metering Devices.

(16) Seller's failure to maintain an enforceable Wheeling Agreement which provides for firm transmission for the Seasonal Contract Capacities and the resulting energy to be delivered by Seller to CP&L under this Agreement.

(17) Seller's failure to comply with applicable laws, rules, regulations and ordinances as required by Section 10 or other applicable provisions of this Agreement.

8.9 Generation and Transmission Outage Coordination and Reporting

a. Outage Coordination.

(1) Seller shall coordinate all Scheduled Outages and Scheduled Reductions with CP&L.

(2) Seller shall at least six (6) months prior to Commercial Operation submit a written maintenance schedule for the first year of the Facility's operations.

(3) Thereafter, Seller shall submit to CP&L in writing by the first day of each Operating Year Seller's desired Scheduled Outage and Scheduled Reduction periods for the next six (6) years indicating the season and amount of each reduction.

(4) Seller shall not schedule any shutdown or reduction in output of the Facility that would decrease the Net Electrical Output of the Facility below the applicable Seasonal Contract Capacity.

(5) Such Scheduled Outages and Reductions shall not exceed twenty-five (25) days in each year except that every fifth year, up to sixty days may be scheduled.

(6) Should circumstances arise which necessitate revisions to Seller's Scheduled Outage/Reductions and which through Seller's reasonable efforts cannot be avoided, Seller shall propose revisions to such schedule. Seller shall exercise its best efforts to provide CP&L with the following notices of such proposed schedule changes:

Expected Duration of Scheduled Outage/Reduction	Advance Notice to CP&L
Less than 7 days	24 hours
7 days to 28 days	7 days
28 days or more	6 months

(7) Seller shall revise its Scheduled Outage/Reduction dates upon CP&L's reasonable request for such changes.

(8) CP&L shall have the right, upon six (6) months prior written notice, to revise the months during which the operator shall not, unless mutually agreed, schedule a shutdown.

(9) Seller shall not remove equipment from service for any type of outage without securing the approval of CP&L's Control Center staff immediately prior to the outage, even if approval had previously been secured, except for Forced Outages which require the immediate removal of equipment from service to avoid extensive damage to equipment or for incidents which may result in injury to personnel.

(10) Seller is entitled to perform any necessary unscheduled maintenance on an emergency basis, as required for operation of the Facility in accordance with Good Utility Practice.

b. Outage Reporting.

(1) Seller shall comply with all current CP&L and NERC generating unit outage reporting requirements, as they may be revised from time to time.

(2) When Forced Outages or Reductions occur, Seller shall notify CP&L's Control Center of the existence, nature, and expected duration of the Forced Outage or Reduction as soon as practical, but in no event later than one (1) hour after the Force Outage or Reduction begins. Seller shall immediately inform CP&L's Control Center of changes in the expected duration of the Forced Outage or Reduction unless relieved of this obligation by CP&L's Control Center staff for the duration of each Forced Outage or Reduction.

(3) Seller shall report to CP&L on a monthly basis all Scheduled Outage/Reductions that occurred during the preceding month within five (5) working days after the end of each month. The data reported shall meet all requirements specified in the NERC Generation Availability Data System ("GADS") Manual. Data presentation shall be in accordance with the format prescribed in the NERC GADS Manual.

8.10 Seller's Failure to Satisfy Reporting Requirements

a. If Seller fails to report Forced Outages or Forced Reductions of magnitudes greater than three percent (3%) of the Contract Capacity within one (1) hour after the Forced Outage or Reduction occurs or otherwise fails to comply with the outage reporting requirements of this Agreement as set forth in Section 8.8 b.(1) and 8.8 b.(3) above, CP&L in addition to making appropriate adjustments in Seller's Availability Adjustment Factor or other reasonable adjustments consistent with the terms and conditions of this Agreement, may, in its sole discretion, take the following actions or charge the following fees for such reporting failures:

(1) For the first Failure, CP&L shall provide written notice to Seller, specifically describing such failure to report; and

(2) For each subsequent failure, CP&L may subtract from payments due to Seller the sum of two thousand five hundred dollars ($2,500) as liquidated damages if the forced outage is less than thirty (30) MW in magnitude or less than thirty (30) minutes in duration; otherwise CP&L may subtract from payments due to Seller the sum of ten thousand dollars ($10,000) as liquidated damages.

b. CP&L's remedies as set forth in Section 8.8 a. are in addition to other remedies which CP&L has under this Agreement or at law.

8.11 <u>Facility Testing for Verification of Seasonal Contract Capacities, Start Time, and Ramp Rate</u>

a. The parties agree to test the Facility from time to time to insure that the Seasonal NDC of the Facility is equal to or greater than the Seasonal Contract Capacity, and to determine whether the Start Time and Ramp Rate performance requirements set forth in Section 2.1i and Section 2.1j are being met. The test shall be run at times to be determined by CP&L in its sole discretion, and may be run prior to Commercial Operation at CP&L's sole option. The verification tests shall include testing of the Facility's Start Time, Ramp Rate, and Net Electrical Output capability as measured at the Delivery Point. Procedures for such tests are set forth in Attachment G. Specific testing dates and times shall be coordinated with CP&L's Control Center.

b. If the Seasonal NDC is less than the Seasonal Contract Capacity, liquidated damages shall be payable under the provisions of Section 6.9 until subsequent tests show that the Seasonal NDC is greater than or equal to the Seasonal Contract Capacity, or until CP&L agrees to reduce the Seasonal Contract Capacity as provided in Section 6.10. Seller may request additional tests to determine whether Seasonal NDC is equal to or greater than Seasonal Contract Capacity only after corrective action sufficient to correct the deficiency has been taken.

c. If the Start Time and/or Ramp Rate performance requirements are not met, the liquidated damages shall be payable under the provisions of Section 6.10 and/or 6.11.

8.12 <u>Fuel Inventories</u>

Seller shall maintain a fuel inventory sufficient for 100 hours of operation at full Seasonal Contract Capacity, unless CP&L gives written approval for a smaller inventory.

8.13 <u>Facility Operator; Evaluations and Reports</u>

a. The Facility operator selected by Seller and any change in the Facility operator must be approved in advance by CP&L.

b. Seller shall cause the operator of the Facility to provide CP&L with copies of any maintenance evaluations or reports that Seller or its operator performs for or obtains from any third party including those with a financial security interest in or lien on the

PUC-IR-9 **(HECO)**

Ref: HECO SOP, Exhibit A at 7 states:

> The ability of an IPP to respond to the utility's needs would be governed by the terms and conditions of the PPA. The only way to provide the PPA with flexibility to adjust to all potential changed circumstances would be to grant the utility the right to act unilaterally to serve its own interests, provided that the facility was not damaged by the utility's actions. To the extent that an IPP is unwilling to grant the utility such rights under a PPA, the utility's flexibility would be diminished.

Is HECO aware of examples of PPAs under which the utility has the right to act unilaterally to serve its own interests, provided that the facility is not damaged by the utility's actions? If not, is it aware of utilities that have unsuccessfully attempted to obtain such a provision? Is it aware of utilities that have included such a requirement in their RFP? Please elaborate.

HECO Response:

HECO is not aware of any examples of PPAs under which the utility has the right to act unilaterally to serve its own interests, provided that the facility is not damaged by the utility's actions. HECO is also not aware of utilities that have unsuccessfully attempted to obtain such a provision or utilities that have included such a provision in their RFP.

A utility's right to unilaterally serve its own interests is limited to circumstances where the IPP defaults on the contract. Even at this point, the utility defers to the Project Lender, who usually has the right to assume all of the rights and obligations of the seller under the contract. The attached provision from the Carolina Power & Light (CP&L) contract contains a fairly standard provision with regard to the rights of the utility to operate the project in case of default (page 22). The page from the CP&L standard contract is attached as pages 3-4.

HECO's firm capacity contracts allow HECO to take over the IPP's operations in the event of an IPP default. See for example, the attached Section 7.2, Rights and Obligations of the

Parties Upon Default from the HECO-AES Barbers Point (AES Hawaii) PPA, attached as pages 5-6.

MODEL POWER PURCHASE AGREEMENT

AGREEMENT FOR THE PURCHASE OF POWER

BETWEEN

CAROLINA POWER AND LIGHT COMPANY

AND

SELLER

DATED ______, 199__

6.4 Operation by CP&L Following Event of Default by Seller

a. If during the term of this Agreement CP&L becomes entitled to terminate this Agreement due to an Event of Default and if operation of the Facility is not assumed by Project Lender or its permitted assignee, then, in lieu of terminating this Agreement, CP&L may, but is not obligated to, assume operational responsibility for the Facility to complete construction, continue operation, complete any necessary repairs, or take such other steps as are appropriate in the circumstances, or may designate a third party or parties to do the same, so as to assure uninterrupted availability and deliverability of electric energy and capacity from the Facility. Seller agrees to fully cooperate with CP&L in providing access to the Facility, and permitting CP&L to operate the Facility as provided herein. Any payments to Seller shall be made only after any and all costs and expenses of CP&L in exercising its rights hereunder are deducted.

b. CP&L's exercise of its rights hereunder to operate the Facility and Seller's Interconnection Facilities shall not be deemed an assumption by CP&L of any liability of Seller.

c. CP&L may continue to operate the Facility until:

(1) Seller demonstrates to CP&L's satisfaction that it is financially and technically qualified to operate the Facility in accordance with this Agreement and resumes operations;

(2) the Project Lender or its permitted assignee assumes operation of the Facility as provided by this Section 6; or

(3) CP&L terminates this Agreement for an Event of Default .

6.5 Consequential Damages

CP&L shall not under any circumstances be responsible to Seller for any incidental, special, consequential or punitive damages whether arising in contract, tort (including negligence), strict liability or otherwise.

6.6 Establishment of Security Funds

a. Seller agrees to establish, fund, and maintain the Security Funds specified below, which shall be available at CP&L's discretion to pay any amount due to CP&L under this Agreement:

(1) A "Development Security Fund" which shall be established and funded as provided in Attachment F within 30 days after the Effective Date, and shall be maintained until such time as (a) the Facility achieves Commercial Operation;

7.2 Rights and Obligations of the Parties Upon Default

A. Termination Rights.

Upon the occurrence of an Event of Default by either party, the non-defaulting party may, at its option, terminate this Agreement by delivering written notice of such termination to the party in default and/or may institute such legal action or proceedings or resort to such other remedies as it deems necessary. Termination under this Section shall be effective sixty (60) days from the date of written notice of termination to the party in default and shall not prejudice any rights of the non-defaulting party.

B. Other Rights Upon Default.

(1) HECO's Assumption of AES-BP's Interest - If an Event of Default by AES-BP occurs, and if HECO gives notice of termination of this Agreement by HECO pursuant to Section 7.2A, HECO at its option, shall have the right, by written notice to AES-BP within thirty (30) days of giving notice of such termination, to assume all of AES-BP's interests, rights and obligations in the Facility to the extent it is legally capable of doing so, to take over the construction or operation of the Facility forthwith and construct or operate the Facility during the period in which the foregoing assumption of AES-BP's interests, rights and obligations is being perfected, and to complete the construction of and/or operate the same, provided that HECO also assumes all of AES-BP's interests, rights, and obligations (except any default charges or similar penalties) under the Financing Documents, Steam Sales Contract, ground lease, and fuel supply contracts and all other contracts which relate to the Facility arising before the date of such assumption. The Financing Documents, Steam Sales Contract, ground lease, fuel supply contracts and other contractual arrangements entered into by AES-BP which relate to the Facility shall specify that HECO has the assumption rights described in the preceding sentence, and that such rights shall have priority over exercise by the Financing Parties of their security interest in this Agreement and/or the Facility. Despite such assumption of rights by HECO, AES-BP and the Guarantor shall continue to be liable to HECO for all obligations to HECO incurred by them prior to HECO's assumption; provided, however, that such obligations shall be reduced for this purpose by an amount equal to the lesser of either (1) the Market Value of the Facility at the time rights under this Section 7.2B(1) are exercised, or (2) the original capital cost of the Facility, plus the cost of any improvements, less (i) any tax depreciation taken and (ii) any outstanding debt secured by the Facility or otherwise assumed by HECO as of the time rights under this Section 7.2B(1) are exercised. AES-BP shall take all action and provide all information necessary to facilitate HECO's decision whether to exercise its rights under this Section 7.2B(1) and to implement the exercise of those rights if HECO

so chooses. AES-BP's obligations under this Section 7.2B(1) shall survive termination of this Agreement by HECO pursuant to Section 7.2A.

(2) Other Assumption of AES-BP's Interest - If HECO elects not to acquire all of AES-BP's interests, rights and obligations in accordance with Section 7.2B(1), the Financing Parties may, at their option, if exercised prior to the termination of the Agreement pursuant to Section 7.2A, and subject to the requirements of this Section 7.2B(2), cause an affiliate of the Financing Parties or a new lessee or purchaser of the Facility to assume all of the interests, rights and obligations of AES-BP under this Agreement arising upon and after the date of such assumption. The right of the Financing Parties to provide such affiliate or new purchaser or lessee shall be subject to HECO's consent, not to be unreasonably withheld, that (i) the affiliate or new purchaser or lessee has the qualifications or has contracted with an entity having the qualifications to operate the Facility in a manner consistent with the original intent of this Agreement; and (ii) that the affiliate or new purchaser or lessee has provided HECO with adequate assurances of its creditworthiness and ability to perform its financial obligations hereunder in a manner consistent with the intent of this Agreement. Notwithstanding such assumption of obligations, rights and interests by the affiliate or new purchaser or lessee, AES-BP and the Guarantor shall continue to be liable to HECO for all obligations to HECO incurred by them up to the date on which the affiliate or new purchaser or lessee makes such assumption effective. The performance or non-performance of the terms of this Agreement by the affiliate or new purchaser or lessee shall be measured from the date of such assumption, purchase or lease. If the assumption of rights, interests and obligations by the affiliate or new purchaser or lessee does occur in accordance with this Section 7.2B(2), the termination of this Agreement noticed pursuant to Section 7.2A shall be null and void and HECO shall continue this Agreement with the affiliate or new purchaser or lessee substituted in the place of AES-BP hereunder.

PUC-IR-10 **(All Parties)**

If the Commission requires competitive bidding, what would be the disadvantages of requiring independent competitors to limit their participation to turnkey projects, at least initially, so that the utility would have maximum control over the project operations upon construction?

HECO Response:

There are a number of project structures common in competitive bidding processes. Certainly, power purchase agreements under which the IPP owns the project and agrees to deliver capacity and energy from the project to the utility based on specified contract terms is a common option. In some recent RFPs, utilities have requested the option for bidders to sell fully or partially completed power plants. For example, Portland General Electric allowed bidders to offer to sell fully or partially completed plants and received a number of such proposals. Turnkey options are another form of project structure that have been bid in recent solicitations. For example, in a recent RFP (RFP 2003-A) in Utah, PacifiCorp selected as its preferred option, a turnkey proposal offered by Summit Energy and Siemens Power. Summit was responsible for project development activities such as permitting, securing financing, and other project development activities. Summit negotiated an EPC contract with Siemens.

One "disadvantage" is that there may be a limited number of bidders capable of or interested in bidding a turnkey arrangement. There also are potential disadvantages with third-party ownership options, and HECO believes that a turnkey option is a viable project structure should competitive bidding be implemented in Hawaii.

PUC-IR-11 **(HECO and KIUC)**

Ref: HECO-CA-IR-32.

a. Please indicate whether power purchase agreements have evolved over time to better allocate risks between the utility and the independent power producer ("IPP"), and if so, identify those factors that have led to this improvement.

b. Please identify those factors that can reasonably be incorporated into future power purchase agreements, and that would help better allocate risks between the utility and the IPP.

<u>HECO Response:</u>

a. As underpinning for this response, it is important to note that the risk allocation provisions in contracts generally deal with the risk sharing between the IPP and the utility and its customer, with the utility acting as an agent for the customer. With this recognition, power purchase agreements have evolved over time to better allocate the risks between the utility/customer and the IPP. In HECO's view, the primary factor contributing to the improvement in risk sharing has been credit quality problems faced by power generators and the associated lowering of the IPPs credit rating. These factors have caused banks and utilities to be more aware of the risks in the contracts and ensure that the risk to the customer is balanced with the ability of the IPP to obtain financing. In addition, new contract structures and financing (i.e., tolling arrangements) have been initiated which are also designed to better allocate risk.

b. Security provisions, liquidated damage provisions and other financial penalties have been commonly used to allocate risk. In some recent RFPs, the level of security required is based on the credit rating of the counterparty. Power generators with high credit ratings are required to post lower levels of development and operating security, while power generators with poor credit ratings (of which there are a significant number) are required to post higher levels of security. (In this context, one of the reasons for HECO's concerns about reliability is the number of IPPs with poor credit ratings.)

In addition, utilities may limit the kinds of security posted to more liquid types, such as a letter of credit rather than a corporate guarantee from a low credit quality entity. Flexibility provisions such as contract buyout and/or deferral provisions have also been used to better allocate risk. For example, a contract buyout provision provides the utility the opportunity to purchase the contract if it no longer needs the power and the cost of purchasing power under the contract exceeds the cost of buying out of the contract. These contract provisions were particularly valuable when the utility was faced with the uncertainty over industry restructuring and retail access at the same time it still maintained the obligation to serve. Recently, gas tolling options have become more common, whereby the utility agrees to manage the gas and pipeline transportation and effectively "runs" its own gas through the IPP facility. Under a tolling agreement, the IPP does not absorb the fuel procurement risk. This risk is transferred to the utility, which may be better able to absorb the risk if it has a portfolio of gas contracts and transportation agreements that could be used to more efficiently manage its overall fuel portfolio. Even before tolling became more common, utilities and IPP agreed to contract provisions that were designed to establish a joint fuel management team to manage the fuel risk.

PUC-IR-12

Ref: HECO-HREA-IR-5(b)(2)at 6 states:

> For example, would the failure to meet predicted system availability become a basis for a penalty? We are not aware of case where this has been done elsewhere. Also, if the utility is not going to be subjected to a penalty, which is the current case with our RPS law, why should the windfarm owner/operator?

a. **(HREA)** Please clarify what the "penalty" would be for, as the term is applied to the utility performance under the RPS law. Is this "penalty" associated with the system availability or reliability provided by the utility?

b. **(All Parties)** What type of provisions can be reasonably incorporated into as-available contracts to encourage the IPP to improve on system availability and/or reliability?

HECO Response:

a. This IR is not assigned to HECO, HELCO or MECO.

b. Availability provisions are common in power contracts, and have been included in some contracts with as-available resources such as wind. For example, Hydro-Quebec recently conducted a solicitation process for wind generated electricity for 1,000 MW and signed contracts totaling approximately 990 MW of installed capacity. Hydro-Quebec received 32 bids with a total of approximately 4,000 MW. The power purchase agreement included in the Call for Tenders documents contained availability provisions whereby the IPP had to guarantee a certain level of generation. Failure to achieve the guaranteed level of generation would result in penalties for non-performance. According to the contract, if the seller failed to deliver the contract energy over a three year rolling average, the seller had to pay a penalty based on the difference between the contract energy and the actual energy delivered times a price established in the contract.

The electric utility subsidiaries of the former Central & Southwest Services (now American Electric Power) issued several RFPs for Renewable Resources, including a wind-only RFP. According to the contract, the seller had to guarantee a certain level of generation over a rolling twelve-month period. If the seller failed to deliver the guaranteed energy, the energy price would be adjusted downward, based on the ratio of total production to guaranteed production.

Copies of the provisions mentioned above from the Hydro-Quebec Wind Generated Electricity Call for Tenders and the renewable resources RFP conducted by the subsidiaries of Central & Southwest Services are attached as pages 3-12 and 13-16, respectively.

In addition, HECO's as-available contracts, which have been executed with several as-available energy developers, have provisions which encourage the IPP to support system availability and reliability. These include standards for ramp rate, power fluctuation rate, reactive consumption, voltage regulation, and underfrequency and undervoltage ride through.

Hydro-Québec Distribution

ELECTRICITY SUPPLY FOR QUÉBEC NEEDS

Call for Tenders Document A/O 2003-02

WIND-GENERATED ELECTRICITY FOR A TOTAL OF 1000 MW OF INSTALLED CAPACITY

Issue date: May 12, 2003
Closing date: June 15, 2004

CHAPTER 2

NEEDS AND REQUIREMENTS

2.1 Type of Product

Through this call for tenders, Hydro-Québec Distribution aims at entering into contracts for the purchase of electricity generated in Québec from wind farms corresponding to 1000 MW of installed capacity. For the purposes of this call for tenders, the term "wind farm" shall signify all of the electricity generation facilities that form part of the bid. A wind farm may only involve a single delivery point where electricity is delivered to Hydro-Québec Distribution. Each wind farm may comprise one or more wind turbines. A bid may only pertain to one wind farm.

Deliveries are characterized by a contract capacity and by an annual amount of energy associated with the contract capacity (contract energy).

The contract capacity and contract energy are established by the bidder and their respective amounts may not be increased during the term of the contract. The contract capacity shall be equal to the installed capacity of the wind farm referred to in the bid. The bidder agrees to deliver each year an amount of energy that is at least equal to the contract energy.

The energy is paid monthly according to the pricing formula in the ~~bid~~. However, if the energy delivered during the course of a given year is greater than 120% of the contract energy, the surplus deliveries shall be paid at a rate of $26.75/MWh, ~~except~~ during the first contract year when such an event occurs (in which case the bid's pricing formula shall apply).

Three (3) years after the commencement of deliveries, and subsequently on each anniversary of the commencement date of delivery, Hydro-Québec Distribution shall calculate the average annual energy delivered during the last three (3) years. When the annual average energy is less than the contract energy, the bidder shall pay damages to Hydro-Québec Distribution. The amount of the damages shall be equal to the product of the amount of missing energy thus established, multiplied by an amount per MWh corresponding to the higher amount between (1) $2/MWh and the (2) difference between the average of the spot market prices of the ISO-NE MCP (*New England Independent System Operator Market Clearing Price*) and NYISO HAM (*New York Independent System Operator Hour Ahead Market*) in zone M, for all the hours in the year, and the price which Hydro-Québec Distribution would have paid for the energy under the contract, with said difference being increased by $5/MWh.

2.2 Environmental Attributes

Hydro-Québec Distribution shall have sole ownership of all environmental attributes associated with the wind farm and its electricity generation.

Note to Supplier:

This document is a translation of the Standard Contract (*Contrat-type*) which, in accordance with Section 4.23 of the call for tenders document, will be written and signed in French only. This document is provided to the Supplier to facilitate reading and may not be used to interpret the *Contrat-type.*

ELECTRICITY SUPPLY CONTRACT

STANDARD CONTRACT – WIND ENERGY

CALL FOR TENDERS A/O 2003-02

BETWEEN

SUPPLIER

AND

HYDRO-QUÉBEC DISTRIBUTION

DATE: ______________

(Translation only)

NOW, THEREFORE, THE PARTIES AGREE AS FOLLOWS:

PART I – DEFINITIONS

1 DEFINITIONS

In the *contract*, unless otherwise indicated by the context, the following expressions have the definitions attributed to them hereinafter:

Billing period

a period of about thirty (30) days corresponding to each of the twelve (12) months of the calendar year that is taken into account for billing purposes;

Business days

Monday to Friday, from 8:00 A.M. to 5:00 P.M., Eastern Time, with the exception of *holidays*;

Commencement date of delivery

in accordance with Section 23, the date on which the **Supplier,** through its *wind farm,* begins delivery of the *contract energy*;

Contract

this electricity supply contract and its appendices;

Contract capacity

a quantity of capacity, expressed in megawatts ("MW"), as indicated in Section 6.1;

Contract energy

a quantity of energy expressed in megawatt hours ("MWh"), as indicated in Section 6.2 or as revised under Section 8, if applicable;

Contract year

a period of twelve (12) consecutive months beginning on January 1 and ending on December 31 of a given calendar year. The first and last *contract years* may have less than twelve (12) months. The first *contract year* begins as of the *commencement date of delivery*;

PART IV – CONDITIONS FOR DELIVERY OF ELECTRICITY

6 CONTRACT QUANTITIES

6.1 *Contract capacity*

The *contract capacity* is set at ____ MW and is equal to the installed capacity of all of the wind turbine generators on the *wind farm*.

6.2 *Contract energy*

The *contract energy* is set at ________MWh for a *contract year* comprising three hundred and sixty-five (365) days (or the revised value pursuant to Section 8).

For a *contract year* that is a leap year or that contains less than three hundred and sixty-five (365) days, the *contract energy* shall be prorated based on the number of days in the year being considered.

For each *contract year,* the **Supplier** agrees to deliver and sell and the **Distributor** agrees to receive and purchase a quantity of energy that is at least equal to the *contract energy*. For any *contract year*, the **Supplier** is deemed to have met its obligation to deliver the *contract energy* if the aggregate of the *eligible energy* and the *energy made available* is at least equal to the *contract energy*.

7 REFUSAL OR INABILITY TO TAKE DELIVERY

7.1 Refusal to take delivery

The **Distributor** may refuse to take delivery of energy and refuse to pay any amount whatsoever with respect to any quantity of energy that is delivered in excess of the *contract capacity* for a given hour.

7.2 Inability to take delivery

The **Distributor** is not obligated to pay any amount whatsoever for any quantity of energy which it cannot take due to a suspension of the *integration agreement* resulting from a default by the **Supplier**.

With the exception of cases where the *integration agreement* has been so suspended or a force majeure has been declared by the *transmission provider*, any quantity of energy not delivered as a result of an inability on the *transmission provider*'s part to deliver the electricity made available to it at the *delivery point* is considered to be *energy made available*. Such *energy* *made available* shall be taken into account when calculating the amount to be paid for energy, as stipulated in Section 14.2. Application of this paragraph shall not have the effect of preventing the **Supplier** from meeting its obligations under Section 6.

However, when the energy is not delivered due to an outage or unavailability of equipment in the switchyard of the *wind farm*, this energy is not taken into account when calculating the *energy made available.*

8 REVISION OF *CONTRACT ENERGY*

After a period of twelve (12) months has elapsed following the *commencement date of delivery,* if, for a given *contract year,* the sum of the *eligible energy* and the *energy made available* is less than the *contract energy*, the **Supplier** may reduce the *contract energy* to a level that can reasonably be maintained based on the performance observed since the commencement of the *contract.* Such revised quantities shall apply as of the commencement of the *billing period* following the receipt of a notice by the **Distributor**. In such case, the **Supplier** shall pay the **Distributor** the damages stipulated in Section 31.

If, following a revision of the *contract energy*, the **Supplier**'s performance deteriorates, Section 8 may apply again.

9 ELECTRICITY DURING TESTING

If applicable, the **Distributor** shall take delivery of the *net delivered energy* during the verification tests provided for under section 5 of the *integration agreement* or any amendment to said agreement which provides for tests similar to those listed in section 5, at the price indicated in Section 14.3, provided that the **Supplier** meets its obligations under the *integration agreement.*

10 DELIVERY SCHEDULES

Five (5) *business days* prior to the beginning of each month, the **Supplier** shall provide the **Distributor** with a monthly delivery schedule which shall include for each hour of said month the delivery rate in MW and the available capacity of the *wind farm*, taking scheduled maintenance into consideration.

In the case of an outage or unscheduled maintenance, the **Supplier** shall immediately inform the **Distributor** of any anticipated decrease in the available capacity and provide the **Distributor** with a revised schedule for the remainder of the month.

All delivery schedules shall be transmitted to the **Distributor** by telephone, fax or e-mail. The schedule for a given hour is expressed by the end time, for example, the time 5:00 A.M. covers the time from 4:00 A.M. to 5:00 A.M.

PART V – PRICING, BILLING AND PAYMENT

14 PRICE OF ELECTRICITY

[This section will be adjusted based on the bid that is retained]

For each *billing period*, the **Distributor** shall pay the **Supplier**, if applicable, the amount payable for the energy delivered determined in accordance with Sections 14.1, 14.2 and 14.3.

14.1 Price for *eligible energy*

During a given *contract year* t, the price E_t paid by the **Distributor** for each MWh of *eligible energy* delivered in accordance with Section 6.2 shall vary as a function of the quantity of *eligible energy* in the *contract year*.

For a quantity of *eligible energy* less than or equal to 120% of the *contract energy*, the price E_t is given by the following formula:

E_t = **[insert the pricing formula for the bid retained]**

where

E_t : price per MWh of *eligible energy* to be paid during *contract year* t.

When the quantity of *eligible energy* in a *contract year* exceeds 120% of the *contract energy*, the price E_t applicable to such excess shall be set at $26.75/MWh; however, no price modification in respect of the *eligible energy* that exceeds 120% of the *contract energy* shall be applied in the first *contract year* in which such excess occurs.

14.2 Amount for *energy made available*

As of the three hundred and sixty-first (361st) hour in which there is *energy made available* in a given *contract year*, in accordance with the definition contained in the second paragraph of Section 7.2, the **Distributor** shall pay the price E_t in force under Section 14.1 for each MWh of *energy made available*.

For a given hour, *energy made available* shall be established based on wind measurements at the *wind farm* and performance curves of the wind turbine generators, also taking into account any equipment that is not available. The result so obtained may not exceed the *contract capacity* multiplied by one hour.

- for the first three (3) percentage points of shortfall, the penalty shall be two thousand dollars ($2,000) multiplied by the *contract capacity* multiplied by the number of these percentage points of shortfall;
- for each additional percentage point of shortfall, the penalty shall be eight thousand dollars ($8,000) multiplied by the *contract capacity* multiplied by the number of additional percentage points of shortfall.

If the *Québec content outside the eligible region* is less than the *guaranteed Québec content outside the eligible region*, there shall be a penalty of one thousand dollars ($1,000) multiplied by the *contract capacity*, multiplied by the number of percentage points of shortfall; however, if the audited *regional content* exceeds the *guaranteed regional content*, the difference between these two (2) values may be subtracted from the number of percentage points of shortfall in the *Québec content outside the eligible region* for purposes of computing the applicable penalty.

30 DAMAGES IN THE EVENT OF DEFAULT TO TAKE OR DELIVER ENERGY

30.1 Default to take delivery

Except as permitted under Section 7, if the **Distributor** fails to take delivery of a quantity of energy made available to it at the *point of delivery*, it shall pay the **Supplier**, at the end of the *billing period*, the price it would have paid in $/MWh pursuant to Section 14.1 multiplied by the quantity of energy not received.

30.2 Default to deliver the *contract energy*

At the third anniversary of the *commencement date of deliveries* and on each subsequent anniversary of the *commencement date of deliveries*, the **Distributor** shall calculate an EMOY value defined as follows:

$$EMOY = (EAN_t + EAN_{t-1} + EAN_{t-2})/3$$

Where

EAN_t: the sum, for the twelve (12) month period then ending ("Period t"), of the quantity of *eligible energy*, the quantity of *energy made available* and the quantity of energy not received for which damages have been paid by the **Distributor** in accordance with Section 30.1;

EAN_{t-1} the sum, for the twelve (12) month period preceding Period t ("Period t-1"), of the quantity of *eligible energy*, the quantity of *energy made available*, the quantity of energy not received for which damages have been paid by the **Distributor** in accordance with Section 30.1;

EAN_{t-2} the sum, for the twelve (12) month period preceding Period t-1, of the quantity of *eligible energy*, the quantity of *energy made available*, the quantity of energy not received for which damages have been paid by the **Distributor** in accordance with Section 30.1;

If the EMOY value for Period t is less than the *contract energy*, the **Supplier** shall pay to the **Distributor** damages corresponding to the difference between the *contract energy* and the EMOY value multiplied by an amount per MWh equal to the greater of:

- $2/MWh and
- the difference between, on the one hand, the average of the hourly spot market prices of the ISO-NE MCP (*New England Independent System Operator Market Clearing Price*) and the NYISO HAM (*New York Independent System Operator Hour Ahead Market*) in zone M, for all the hours in Period t and, on the other hand, the price that the **Distributor** would have paid for the energy under Section 14.1 during Period t, plus $5/MWh.

31 DAMAGES IN THE EVENT OF A REVISION OF THE *CONTRACT ENERGY*

In the event that the *contract energy* is permanently revised downward, under Section 8, the **Supplier** shall pay an amount to the **Distributor** calculated as follows:

$$DOM = (CA - CB) \times CF \times PC / CH$$

where

DOM: amount of damages;
CA: *contract energy* in effect prior to the revision;
CB: *contract energy* in effect after the revision;
CF: an amount of $12,000/MW if the revision occurs prior to the tenth (10th) anniversary of the *commencement date of delivery* or an amount of $20,000/MW otherwise;
PC: *contract capacity*
CH: *contract energy* in effect at the *commencement date of delivery*.

Section 31 shall apply each time there is a permanent revision of the *contract energy* under Section 8.

32 DAMAGES IN THE EVENT OF TERMINATION

32.1 Termination following an event related to Section 35.1

If the *contract* is terminated following a default related to Section 35.1, the **Distributor** shall be entitled to damages calculated by multiplying the *contract capacity* by one of the following amounts:

- if the termination occurs more than eighteen (18) months before the *guaranteed commencement date of delivery*, the amount shall be $10,000/MW;
- if the termination occurs eighteen (18) months or less before the *guaranteed commencement date of delivery*, the amount shall be $20,000/MW.

32.2 Termination following an event related to Section 35.2

If the *contract* is terminated following a default related to Section 35.2, the Party that terminates the *contract* shall be entitled to damages calculated by multiplying the *contract capacity* by one of the following amounts:

- if the termination occurs on the *commencement date of delivery* or before the tenth (10th) anniversary of the *commencement date of delivery*, the amount shall be $20,000/MW;

- if the termination occurs on the Date for Reduction of Operating Security or before the tenth (10th) anniversary of the *commencement date of delivery*, the amount shall be $12,000/MW;

- if the termination occurs between the tenth (10th) anniversary of the *commencement date of delivery* and the end of the *contract*, the amount shall be $20,000/MW;

and the result shall be multiplied by the ratio obtained by dividing the *contract energy* in effect at the time of termination by the *contract energy* in effect at the *commencement date of delivery*.

33 LIQUIDATED DAMAGES

Payment of the amounts stipulated in Sections 29, 30, 31 and 32 is the only compensation which the Parties may claim for any damages incurred as a result of any of the breaches or defaults mentioned in these provisions.

AGREEMENT FOR

THE PURCHASE OF RENEWABLE
[SMALL-SCALE /DISTRIBUTED RESOURCES] GENERATION

FROM THE ______________ PROJECT

BY AND BETWEEN

SOUTHWESTERN ELECTRIC POWER COMPANY

AND

____

DATED ____________________, 199_

APPENDIX D

Determination of Contract Pricing

D.1 Capacity Payment

A. Capacity payments shall be calculated pursuant to this Appendix D and shall be made monthly to Seller subject to the terms and conditions of the Agreement.

B. The capacity charge set forth in Schedule 4-1 of the Response Package shall be multiplied by the Net Capability and by the Monthly Availability Adjustment Factor set forth in Section D.2 of this Appendix D.

D.2 Availability Adjustment Factor

A. Availability Adjustment Factor is defined as:

$$AAFM = \frac{EAF \text{ X } SAF}{TEAF}$$

where:

AAFM= Monthly Availability Adjustment Factor;

EAF = Equivalent Monthly Availability Factor, as further defined in Subsection D.2 (B), below.

TEAF = Annual Target Equivalent Availability Factor proposed by bidder. Tab 4 of the Response Package.

SAF = Seasonal adjustment factor set forth below for each month of the year.

If the Facility's Equivalent Monthly Availability Factor is higher than the TEAF specified, a monthly premium will be applied. However, payments to the bidder will be capped on a rolling 12 - month historical basis at the sum of the specified 12 - month capacity and fixed O&M price bid set forth in Appendix A.

APPENDIX D (Page 2 of 3)

Determination of Contract Pricing

The Seasonal Adjustment Factors are as follows:

Jan	1.00	July	2.10
Feb	.20	August	2.10
March	.20	Sept.	2.10
April	.20	Oct.	.70
May	.90	Nov.	.20
June	1.40	Dec.	.90

(B) Equivalent Monthly Availability Factor. The Equivalent Monthly Availability factor is determined by the Facility's outages resulting form both its reported outages and its economic dispatch performance, as follows:

$$EAF = \frac{\text{Available Generation in on-peak hours X 100}}{\text{Maximum Generation}}$$

$$= \frac{AH - (EUNDH + ESDH)\ X100}{PH}$$

AH = The number of hours a unit was in the available state. Available hours is the sum of service hours and reserve shutdown hours, or could be computed from period hours minus unavailable hours.

EUNDH = Equivalent Unit Derated Hours. This represents the available hours during which a derating was in effect, expressed as equivalent hours of full outage at maximum capacity.

ESDH = Equivalent Seasonal Derated Hours. This represents the available hours during which a derating was in effect, expressed as equivalent hours of full outage at maximum capacity.

PH = The number of hours a unit was in the active states provided that the Net Capability shall be set equal to the Net Capability as determined in the most recent Summer or Winter test period, as appropriate to the current month, unless re-established by a more recent test.

APPENDIX D (Page 3 of 3)

Determination of Contract Pricing

D.3 Energy Payments

A. Energy Payments shall be calculated monthly pursuant to this Appendix D and shall be made monthly to Seller according to the terms and conditions of this Agreement.

B. The Energy Payment for each month shall be product of the number of KWH's delivered to Buyer during the preceding month, the Adjusted Energy Rate as determined pursuant to the provisions of Subsection D.3 (D) below, and the on-peak and off-peak multiplier.

C. The on-peak multiplier shall equal 1.2 for deliveries during December, January, February, June, July and August. The off-peak multiplier for all other months shall be .8.

D. Adjusted Energy Rate for Energy Sales by Seller to Buyer.

The Adjusted Energy Rate for all MWH received by Buyer from Seller on or after the Commencement Date of Operation shall be the Energy Price specified on Schedule 4-1 of the Response Package multiplied by the Energy Rate Adjustment Factor set forth in Subsection D.3(E) below.

E. Energy Rate Adjustment Factor for Seller's Non-Production.

The Energy Rate Adjustment Factor shall be unity (the number 1) unless total and/or on-peak and/or off-peak energy production deliveries by Seller to Buyer are less, respectively, than the guaranteed total generation and/or guaranteed on-peak and/or off-peak generation for any rolling 12-month period. In the event of any such shortfall, until any and all such shortfalls are eliminated, the Energy Rate Adjustment Factor shall be the smallest of the fractions calculated over a rolling 12-month period as (i) the ratio of the total production delivery to the guaranteed total generation; (ii) the ratio of the on-peak energy production delivery to the guaranteed on-peak energy generation; and (iii) the ratio of the off-peak energy production delivery to the guaranteed off-peak energy generation.

PUC-IR-14 **(HECO)**

Ref: CA-HECO-IR-12 at 4 states:

> On September 21, 1987, HECO withdrew its application in Docket No. 5778 after it determined that the power purchase alternative was superior.

a. Why was the power purchase alternative superior?

b. What were the specific factors and attributes of the power purchase alternative that caused HECO to withdraw its application?

c. Would HECO have been likely to proceed with the Docket No. 5778 application process and proceeded with development and completion of Kahe 7 at that time, if it had not issued the solicitation for power purchase proposals?

<u>HECO Response:</u>

a. HECO's reasons for signing a power purchase agreement with AES-Barbers Point, Inc. ("AES-BP", now known as AES Hawaii, Inc.) were described in Docket No. 6177 (AES Power Purchase Contract). The following summarizes the reasons:

In its testimonies and exhibits in Docket No. 6177, HECO demonstrated that the cost for the Purchased Power Agreement with AES-BP dated March 25, 1988 (the "Contract") was reasonable and was less than HECO's estimated long-term avoided costs. The basis for these conclusions was that HECO's revenue requirements with the AES-BP facility included in HECO's capacity expansion plan were less than HECO's revenue requirements with HECO constructing and operating an oil-fired 146 MW facility at Kahe (i.e., Kahe 7 addition).

In addition, in Docket No. 6177, HECO demonstrated that there were other factors which were difficult to quantify in a cost analysis, that favored the AES-BP alternative. The factors that favored the AES-BP alternative included (1) the AES-BP project helped promote Hawaii's long-term energy objective of reducing Hawaii's dependence on oil, (2) the AES-BP project would facilitate the development of bulk handling facilities at the Barbers Point Harbor, (3) HECO's purchase of power from a qualifying cogeneration facility was consistent with PURPA, and the Commission's rules implementing PURPA, and (4) the Contract and AES's track record provided assurance that the AES-BP facility would supply utility quality power to HECO and its customers.

In Decision and Order No. 10448 ("D&O 10448"), filed December 29, 1989, the Commission found that the "energy and capacity charges to be paid by HECO pursuant to the [AES-BP] power purchase agreement, as amended, are at or below HECO's long-term avoided costs and are reasonable." (D&O 10448, page 41.)

b. See the response to subpart a.

c. Yes, without the purchase power alternatives, HECO would have likely proceeded with its efforts to develop the Kahe 7 project if the required permits and approvals were obtained.

PUC-IR-15

(HECO) Ref: CA-HECO-IR-12 at 4 states:

> Because of the short lead time available to have additional generation in place by October 1990, HECO pursued alternative ownership options in parallel with its Kahe 7 approach.

Also Ref: CA-HECO-IR-13(b).

a. It appears that the HECO companies did not pursue alternative ownership options in parallel with generating facilities listed in response to CA-HECO-IR-13 and as referred to in CA-HECO-IR-13(b). If this understanding is correct, please explain why the HECO companies did not pursue this type of parallel planning process for the newer facilities, but did use this approach with the Kahe 7 unit.

b. Why was competitive bidding not considered by HECO, MECO and HELCO as an alternative for any of the unit additions?

c. Was a process similar to HECO's 1987 solicitation of power purchase proposals considered as an alternative for any of the unit additions, and if not, why not?

d. What assurances can HECO, MECO and HELCO provide that a competitive bid or solicitation for power purchase proposals would not have met the generating facility requirements either sooner or at lesser expense?

e. Could purchased power alternatives potentially have offered other benefits, similar to the instance where "AES-BP's use of coal provided HECO with a valuable opportunity to diversify its fuel base on Oahu"? (See CA-HECO-IR-12 at 6.)

HECO Response:

a. As stated in HECO's response to CA-HECO-IR-13, part b. in this proceeding, competitive bidding was not considered by HECO, MECO and HELCO as an alternative for HECO's simple cycle peaking unit at Campbell Industrial Park, MECO's Maalaea Unit Unit 18 and Waena Unit 1, and HELCO's Keahole Unit ST-7.

HECO has gained a great deal of experience with operation of electrical grids with substantial portions of the power provided by Independent Power Producers ("IPPs") since 1987, when HECO solicited power purchase proposals. As stated in Exhibit A, page 12 of the HECO Companies' Statement of Position ("SOP"), "HECO already relies on non-utility generation to meet a significant portion of its power supply requirements." HECO further stated "The presence of a Power Purchase Agreement ("PPA") between the utility and an IPP does not provide the utility with as much operating flexibility as the utility has with its own units." (SOP Exhibit A, page 5.) The HECO Companies provided several examples on pages 5 and 6 of Exhibit A. HECO also stated that "A utility has much more flexibility to adjust to changed circumstances if it owns and operates its own units, than if it purchases power under long-term PPAs, because PPAs cannot be drafted to provide for all future contingencies and changed circumstances." (SOP Exhibit A, page 6). Furthermore, HECO stated in its response to HREA-HECO-IR-9 that existing IPPs have caused operational or reliability problems and provided several examples on pages 2 to 6 of that response.

Background for Current Generating Unit Projects

In order to respond to this IR, it is first necessary to clearly establish the circumstances under which the four generating units that are the subject of CA-HECO-IR-13(b) are planned to be added to the systems of MECO, HELCO and HECO.

1. Maalaea Unit 18 ("M18")

M18 is the steam turbine generator that will complete a dual-train combined cycle facility ("Maalaea DTCC No. 2") at MECO's Maalaea Generating Station. The application for this project was filed June 23, 1993, and was approved by Decision and Order No. ("D&O") 13730 (January 11, 1995) in Docket No. 7744. The first nominal 20MW combustion turbine ("CT") was placed in commercial operation in December 1998. The second nominal 20MW CT (M19) was placed in commercial operation in September 2000.

The steam turbine generator, and related facilities, are expected to be placed in service in February 2006.

As a result of D&O 13730, MECO submitted a review every year following the decision reviewing the continuing need for the next phase of the project. MECO submitted ten annual reviews, the last of which was filed March 31, 2005.

The phased installation of Maalaea DTCC No. 2 was, in part, a parallel plan to the continued operation of the HC&S bagasse-burning renewable facility, since continuing uncertainty as to whether or when HC&S might terminate its sugar operations required that MECO be very flexible as to when the next phase of the DTCC No. 2 facility would be installed.

2. Keahole Unit ST-7

Keahole Unit ST-7 also is a steam turbine generator that will allow HELCO to complete the installation of a DTCC facility at Keahole. The first two phases were nominal 20MW CTs that were installed in 2004. The installation of CT-4 was initially driven by uncertainty regarding whether Puna Geothermal Venture ("PGV") would be able to install its 25 MW facility, and whether two sugar mills (which subsequently went out of business) would continue to provide power to HELCO, as well as by load growth on the Big Island. The Amended Application for CT-4 was filed September 30, 1992 in Docket No. 7048, and was approved by D&O 13050 (January 21, 1994).

HELCO filed its application for CT-5 and ST-7 on February 26, 1993 in Docket No. 7623, due in part to uncertainty with respect to purchased power, and in part due to growing load on the Big Island and the need to retire older units. See D&O 14284 (September 22, 1995). In parallel with pursuing the permits and approval necessary to install its own generation, HELCO negotiated a power purchase agreement with the entity now known as Hamakua Energy Partners, L.P. ("HEP"), and was able to delay the installation of ST-7 (while continuing to pursue the installation of CT-4 and CT-5) when HELCO successfully negotiated a power purchase agreement with HEP and the agreement was approved by the Commission, and HEP was able to obtain its permits and complete its installation. HELCO has filed monthly status reports since 1995 in Docket No. 7623 regarding the status of its Keahole projects.

As stated above, the installation of ST-7 will allow HELCO to complete the installation of a fuel-efficient DTCC facility. Conversion of simple cycle units to combined cycle units increases system fuel efficiency since the steam cycle in the combined cycle utilizes energy in the combustion turbine exhaust that would otherwise be unused. In addition, an initial installation of a simple cycle unit and later conversion to combined cycle allows capacity to be installed in increments to better match load growth. Therefore, planning flexibility will be maintained if a simple cycle combustion turbine installed now to meet current capacity needs can later be converted to a combined cycle configuration if necessary to meet future load growth.

In addition, as HELCO has noted on numerous occasions, there is a mismatch between the location of generation on the east side the island of Hawaii, and the allocation of load between the east and west sides of the island of Hawaii. Completion of a base-loaded facility at Keahole, which is basically in the center of the west-side load, will provide important system benefits as well as additional generation. The completion of ST-7 was also a part of the land use settlement allowing the completion of CT-4 and CT-5.

This is particularly important given HELCO's continuing efforts to expand the amount of renewables on its system. HELCO has approved power purchase agreements or amended agreements with HRD for a 10MW wind farm and with Apollo to expand its wind farm from 7MW to 20MW, and earlier added 5MW to the existing 25MW from the PGV facility on the east-side of Hawaii.

3. CIP Unit 1

This project involves the installation of a nominal 100MW combustion turbine, that will be used as a peaking unit. The CT should be able to burn bio-derived fuels if this becomes available in the future. At this time, a simple cycle combustion turbine is preferred over cycling and base load generation technologies because it will (i) fill the need for peaking capacity to provide quick start firm generation capacity, and (ii) provide spinning reserve and quick load pickup capacity in conjunction with the daily operations of HECO's fourteen existing steam generating units, two existing peaking combustion turbines and three Independent Power Producer base load generating units. The addition of a peaking unit will also facilitate the future integration of as-available renewables and/or firm capacity renewables with minimum take provisions into the HECO system.

Given the lead time necessary to install even a simple cycle CT, HECO began the process of preliminary engineering work in 2002 and began efforts to obtain the Covered Source Permit ("air permit") for a nominal 100 MW simple-cycle CT in January 2003. HECO submitted an initial application for the air permit with the State of Hawaii Department of Health ("DOH") in October 2003. The DOH deemed the initial application complete in November (the HECO IRP-3 Advisory Group was informed of the air permit application at the October 7, 2003 IRP Advisory Group meeting). In December 2004, HECO submitted an amendment to its initial air permit application, in part to allow for the possibility that a second simple-cycle combustion turbine may be needed sooner than projected (for example, if energy efficiency and load management DSM, CHP and renewable energy program imports are not fully realized, or if system demand increased more than projected). The DOH deemed the revised air permit application for two simple-cycle combustion turbines complete in February 2005 and is currently in the process of reviewing the application.

In 2004 and 2005, HECO continued with efforts to permit, design, and install its next generating unit and a 2-mile long 138 kV transmission line between the AES substation and CEIP substation. These efforts included: (1) Continuing to work with the DOH and EPA to facilitate the review of the air permit application; (2) Meeting with west Oahu neighborhood boards and community leaders to present HECO's plans; (3) Selection of an engineering firm to begin the necessary engineering work to develop conceptual layouts of the next generating unit and to specify and select the combustion turbine package through a competitive bidding process without commitments to purchase; (4) Determining the Accepting Agency for the Environmental Impact Statement ("EIS"), so that the EIS Preparation Notice can be published; and (5) Working with neighboring communities on a "community give back" plan for the new unit.

HECO issued a Request For Proposals for a nominal 100 MW combustion turbine on April 8, 2005, to three vendors including Alstom, Siemens-Westinghouse, and General Electric. The Alstom and Siemens-Westinghouse units have a capacity of approximately 107 MW. The General Electric unit, which was used as a proxy for the 100 MW class of simple cycle combustion turbines for IRP-3 due to the availability of vendor-supplied data for the unit, has a capacity of approximately 76 MW. HECO received on May 25, 2005 bids from the three vendors to furnish a nominal 100 MW combustion turbine.

HECO plans to file the application for approval to commit funds for the CT in June 2005. However, given the long lead time of the permitting, engineering, equipment procurement and construction activities, it appears that 2009 is still the earliest that permitting and installation of the simple-cycle combustion turbine can be expected to be completed.

4. Waena Unit 1

Waena Unit 1 is a nominal 20MW CT to be added at MECO's new generating station at Waena. This CT could be converted into a DTCC if MECO needs to add additional fossil-fuel generation in the future. MECO undertook an extensive process to re-zone the property to industrial so that generating units could be added, and completed in extensive EIS process in order to re-zone the property.

The timing of the Waena 1 addition will depend, to some extent, on the status of the HC&S facility, which will continue to provide power to MECO at least through 2007, but will continue on a year-to-year basis thereafter unless HC&S agrees to another arrangement.

Factors Considered in Not Competitively Bidding the Capacity to Third Parties

The Companies identified a substantial number of Hawaii-unique factors that should be considered in determining whether competitive bidding should be implemented, and how competitive bidding is implemented if it is implemented. An evaluation of these factors shows that there are substantial differences between the circumstances at the present time, and the circumstances at the time HECO issued an RFP in parallel with applying for approval to commit funds for its own Kahe 7 unit. These factors include, without limitation:

1. All the costs incurred by the utility as a result of purchasing power should be taken into account.

At the time HECO issued an RFP, HECO's understanding from the credit rating agencies was that there would be no impact on its credit rating as a result of entering into firm power purchase agreements. The credit rating agencies subsequently changed their view of firm capacity arrangements, and began to impute debt, which resulted in the need to rebalance the utility's capitalization. Initially, imputed debt was based on 15% of the net present value of the fixed obligations under the power purchase agreement. This was subsequently increased to 30%. The Companies have rebalanced their capitalizations, and the rebalanced capitalizations have been recognized in the rate making process, but the need to rebalance has not been recognized in the calculation of avoided costs. See responses to CA-IR-19, HREA-HECO-IR-8, HREA-HECO-IR-26, HREA-HECO-IR-27.

More recently, new accounting requirements have raised issues as to whether power purchase agreements will have to be treated as capital leases, or whether the income statements and balance sheets of independent power producers will have to be consolidated with those of the utility. See Exhibit C to HECO's SOP, and response to HREA-HECO-IR-31. At the present time, there is substantial uncertainty as to the impact of new firm power purchase agreements on the utility's balance sheet.

2. The percentage of purchase power that a utility has, and the impact on its operational flexibility, should be considered.

The percentage of firm capacity provided by IPP's on HECO's system has increased from 0% prior to the RFP to approximately 25% today. HECO has been able to manage the integration of the Kalaeloa, AES and H-Power facilities into its system, but there is substantial uncertainty as to how much more firm power could be purchased without substantial negative impact on HECO's operational flexibility. Moreover, it is expected that there will be opportunities in the future to purchase additional renewables on a firm capacity basis (for example, if an additional waste-to-energy capacity is added at Campbell Industrial Park), and if the percentage of purchased power is increased it should be accompanied with the benefit of adding renewables.

HELCO also has a substantial percentage of firm purchase capacity on its system, and expects to have the opportunity to purchase additional firm renewable capacity in the future.

3. The timing of the need for additional generation, and the time required to permanently install new generation, should be taken into consideration.

Recent experience indicates that the time required to permit and install new generation on any of the islands is significantly longer than it was expected to be at the time HECO issued the RFP. For example, there is now a requirement that an environmental impact statement be undertaken for a fossil-fuel generating unit that exceeds 5MW in size.

HECO estimates that the lead time to permit and install a simple-cycle combustion turbine is approximately seven years, without the added time necessary to complete a well-designed competitive bidding process.

Efforts to install HECO's simple cycle peaking unit at Campbell Industrial Park have been under way since 2002. Although the capacity to be provided by the unit is needed now, the unit is not expected to be installed sooner than 2009, because of the long lead time for environmental review, permitting and approvals, equipment procurement and construction. A well-designed and effective competitive bidding process cannot be put into place and completed soon enough. Based on the experiences in other states, it may take two years or more to develop the bidding rules. Once the rules are established, it may take two years or more to prepare an RFP, solicit proposals, evaluate the proposal, select the winning bidder and negotiate a contract. It could then take another several years for the utility to obtain approval of the contract, and the selected bidder to obtain the necessary permits, procure the necessary equipment, and construct the unit. Under competitive bid process, it is likely that the unit would not be installed until several years beyond 2009.

Units can be permitted and installed much faster on the mainland. See attached pages 16-19.

4. The need for flexibility as to when additional generation is added needs to be maintained.

Given state energy policy, the Companies have been aggressively pursuing resources other than fossil-fuel generation, including energy efficiency demand-side management ("DSM") programs, load management DSM, combined heat and power systems, and renewable energy generation.

As a result, the utilities need to be able to adjust their plans to add new fossil-fuel generation to take into account their success or lack of success in obtaining the necessary approvals to implement these other resources, and their success in obtaining customer acceptance of these resources (since they are often dependent on the plans of third-parties other than the utilities), and to adjust for changes in load growth.

5. The type of generation added needs to take into account the potential impact on renewable resources.

Developers of IPP projects generally prefer to build base-loaded facilities with substantial minimum take provisions. In order to accommodate renewables, HECO and MECO plan to add combustion turbines that can be used as peaking units, while maintaining the flexibility to incorporate the CTs into combined cycle units if the need for additional generation develops.

6. The type of generation, and the generation's fuel source, should be taken into consideration.

The most successful IPP projects have been those where the utility was able to take advantage of a resource that could be developed by a third-party with expertise in developing that resource. Examples would include PGV's geothermal facility, H-Power's waste-to-energy facility, Kalaeloa's facility, which was only the second combined cycle facility to be fired on LSFO (and which made the continued participation of the manufacturer of the facility an essential element of the power purchase arrangement), and AES Hawaii, which utilizes a circulating fluidized bed technology pioneered by AES. This consideration does not apply to the four projects listed above.

Summary

With respect to Maalaea Unit 18, an alternative ownership option was considered impractical, as the installation of that unit will complete the conversion of MECO's existing simple cycle combustion turbines Maalaea Units 17 and 19 to a 2-on-1 combined cycle unit. The conversion requires that two heat recovery steam generators and a steam turbine-generator (Unit 18) be integrated with the existing Units 17 and 19. Unit 18 will be installed on MECO property and it is impractical to demarcate boundaries and associated responsibilities for all utility and non-utility facilities, including buildings, access lanes, laydown areas, and integrated piping, ductwork and wiring, if Unit 18 was to be non-utility owned. Moreover, non-utility ownership of Unit 18 would likely require duplication of utility and non-utility operational and maintenance staffs, resulting in higher overall operational expense and unwieldy complications in the coordination of work and schedules for the integrated combined cycle unit. However, although it is impractical for Unit 18 to be non-utility owned, all major equipment and construction services for Unit 18 will be procured through competitive bidding processes.

If, instead, a competitive bidding for new generation process were used to secure stand-alone replacement capacity that would otherwise be provided by utility installation of Unit 18, the conversion of Units 17 and 19 to combined cycle would not occur (or would occur at a much later date), and the opportunity to increase the generating efficiency of Units 17 and 19 would be lost or substantially delayed.

Similarly, with respect to Keahole ST-7, installation of that unit will complete the conversion of existing simple cycle combustion turbines Keahole CT-4 and CT-5 to a 2-on-1 combined cycle unit. The same concerns about competitively bidding the Maalaea Unit 18 would apply to Keahole ST-7. In addition, the completion of ST-7 is needed to place baseloaded generating capacity on the west side of the island for voltage support.

With respect to HECO's simple cycle peaking unit at Campbell Industrial Park and MECO's Waena Unit 1, which will also be a simple cycle peaking unit, competitive bidding was not considered because of the concerns identified above.

b. See the response to part a above.

c. A process similar to HECO's 1987 solicitation of power purchase proposals was not considered as an alternative for any of the unit additions. First, competitive bidding processes are evolving with the changes in the power market. Therefore, it would not be appropriate to use a process modeled after HECO's 1987 solicitation of power purchase proposals to secure proposals in today's environment. (See SOP Exhibit A, page 32.)

Second, as explained in part a. above, HECO, HELCO and MECO have concerns over increasing proportions of IPP generation on the respective islands.

Third, IPPs already have the opportunity to propose projects that can deliver power at less than the costs of the utility's alternatives. (SOP Exhibit A, page 14). An alternative competitive procurement process has been implemented in Hawaii as a result of the Public Utilities Regulatory Policies Act of 1978 ("PURPA"). Qualifying facilities are allowed to submit offers to sell firm capacity and energy to the utility at prices at or below avoided costs, pursuant to the rules established by the Federal Energy Regulatory Commission under PURPA, and state rules (such as those in Title VI, Chapter 74 of the Hawaii Administrative Rules) implemented pursuant to FERC rules.

d. It is impractical for HECO, HELCO and MECO to provide "assurance" or complete certainty that a competitive bid or solicitation for power purchase proposals will not meet the generating facility requirements either sooner or at lesser expense. In order to make a determination as to whether or not a non-utility project actually met a generating facility requirement sooner than a utility project, both projects would have to be completed and the results compared. Otherwise, if only one project is built, the potential result of the alternative would simply be a matter of speculation.

Similarly, with respect to whether a competitive bid or solicitation for power purchase proposals results in meeting the generating facility requirements at lesser expense compared to a utility-build option, both projects would need to be built, operated and maintained, and the total expenses compared after the end of the contract life (which may be 30 years or more) of the power purchase option. If only one project is built, then the potential cost result of the alternative would again be a matter of speculation.

While the HECO Companies did not employ a competitive bid or solicitation process seeking power purchase proposals, HECO, HELCO and MECO typically obtain the engineering, construction management, equipment procurement and construction services, and all major equipment through competitive bidding processes. These components typically comprise the vast majority of the total project cost.

e. HECO, HELCO and MECO are installing specific types of units to best meet the needs of their respective systems. The installation of Unit 18 (which itself will not consume fuel) will improve Maui's system fuel efficiency increasing the efficiency of Units 17 and 19. The installation of a different type of unit may not provide the same fuel efficiency improvements that Unit 18 will provide. Moreover, the installation of a different type of capacity elsewhere on the island could result in the need for transmission system upgrades depending on where the capacity is located.

Similarly, for HELCO, the installation of ST-7 at Keahole will improve HELCO's system fuel efficiency by increasing the efficiency of Units CT-4 and CT-5. ST-7 itself will not consume fuel. Furthermore, the combined cycle unit to be formed by the integration of ST-7 with CT-4 and CT-5 will provide efficient baseload capacity on the west side of the island where it is needed to provide voltage support. The installation of a different type of unit elsewhere on the island may not provide the same system benefits that ST-7 will provide. Additionally, the installation of a different type of capacity elsewhere on the island could result in the need for transmission system upgrades depending on where the unit is located.

On Oahu, analyses indicate that peaking capacity is the most cost-effective type of capacity that should be installed. While purchased power alternatives can potentially offer other benefits (such as the fuel diversity benefit provided by AES Hawaii's use of coal), the installation of additional baseload capacity on Oahu may actually increase total system costs over the long term.

Similarly on Maui, analyses indicate that peaking capacity is the most cost-effective type of capacity that should be installed after Unit 18 is installed. Therefore, while purchased power alternatives can potentially offer other benefits, the installation of a type of generating capacity other than peaking capacity in place of Waena Unit 1 may actually increase total system costs over the long term.

Mainland Timeframes

Bid, Permit and Install (under Florida's pre-established rules)

Florida Power & Light Company ("FPL") completed a Need Study that identified a need for 1,066 MW of additional capacity to meet the needs of its customers and provide adequate reserve margins in 2007.

Pursuant to Florida Public Service Commission ("PSC") rules, FPL developed a request for proposals (RFP), which was issued on August 25, 2003. FPL notified potential participants that it would evaluate the RFP proposals against or potentially in conjunction with a self-build option located at FPL's existing Turkey Point site in Dade County, Florida. FPL received five proposals (some of which did not meet minimum requirements) from four utilities, and evaluated all proposals before selecting its self-build combined-cycle option, Turkey Point Unit 5.

FPL filed a petition with the Florida PSC on March 8, 2004 for the determination of need required by Florida statute and rule, and the PSC granted the determination of need by Order No. PSC-04-0609-FOF-EI, issued June 18, 2004 in Docket No. 040206-EI. The Florida PSC found that:

> FPL's and the independent evaluator's extensive economic evaluations of these proposals included quantifying and considering generation-related costs, transmission-related costs (including transmission interconnection and integration costs, energy and capacity losses and increased operational costs), as well as the impact of each portfolio on FPL's capital structure minus mitigating factors offered by purchased power options. FPL calculated each option's transmission-related costs by calculating the revenue requirements associated with transmission interconnection and integration for each option as well as each option's impact on FPL's transmission losses and costs of operating less efficient gas turbines in Southeast Florida.
>
> The impact of purchased power portfolios on FPL's capital structure was recognized by an equity adjustment according to the methodology contained in the RFP. Because rating agencies treat a portion of a purchasing utility's firm capacity payment as an off-balance sheet obligation, the equity adjustment represents a real cost associated with purchasing power that must be recognized in assessing purchased power options. Purchased power options provide some mitigation, through completion and performance

security, to potential costs the purchasing utility might otherwise incur through a self-build alternative. This mitigating value was estimated and factored into the evaluation. The value of the mitigation is applied in the equity adjustment calculation to offset the cost of portfolios containing purchased power options. The sum of each portfolio's generation costs, transmission costs, and cost impact on capital structure minus the mitigating factors represented the total system costs to FPL customers for the portfolio.

The time required to complete the RFP process and obtain approval for the project was ten months, with the combined cycle facility expected to be in service about three years thereafter.

<u>Bid, Permit and Install (under Utah's stipulated "rules")</u>

A second case in point is the recent bidding process in Utah conducted by PacifiCorp (dba Utah Power & Light).

PacifiCorp's IRP and Action Plans were accepted by the Utah PSC (by Order Acknowledging IRP and Action Plans "conform to applicable guidelines") on June 4, 2003. The IRP Plan was updated, on October 30, 2003, while the competitive bidding process was on-going in light of PacifiCorp's increasing need for capacity in Utah.

A process to develop open bidding guidelines had been initiated March 6, 2003. In order to allow the process to meet PacifiCorp's current needs, the parties submitted a "Stipulation Regarding Outside Evaluation" dated June 4, 2003 (under which an independent "evaluator" submitted reports on the utility's "next best alternative" (July 2003), the utility's screening review process (November 2003), and the final selection (February 2004).

The utility issued an RFP on June 6, 2003, and solicited proposals for new peaking and base-loaded capacity.

In the peaking unit category, PacifiCorp selected its self-build option. The Utah PSC, by Report and Order issued March 5, 2004 in Docket No. 03-035-29, granted a certificate of public convenience and necessity ("CPCN") for a staged, 280 MW, natural gas-fired simple cycle combustion turbine ("CT") for service in the summer of 2005, with conversion to a 525 MW combined-cycle facility in 2006 at PacifiCorp's Currant Creek plant site. PacifiCorp's application for a CPCN was filed November 3, 2003. PacifiCorp identified date of delivery and dispatchability, along with price, as the most important characteristics of the new generation. The evaluation process also considered the residual value of PacifiCorp's ownership of the unit.

The time required to complete the RFP process and obtain approval for the peaking unit project was nine months, with the first CT expected to be in service 14 months thereafter.

In the baseloaded unit category, for which the evaluation process was completed in May 2004, PacifiCorp selected a turnkey, 534 gas-fired plant offered by Summit Energy Group (dba Summit Vineyard, LLC), over an IPP proposal from Calpine for a 817 MW gas-fired plant. PacifiCorp filed an application for a CPCN for this Lake Side Power Project on May 28, 2004. Calpine was allowed to intervene, but withdrew on July 10, 2004. The Utah PSC granted a CPCN by Report and Order issued November 12, 2004 in Docket No. 04-035-30. The base-loaded combined cycle facility is expected to be available in the summer of 2007. (A gas-fired facility was selected, instead of the coal-fired facility in the IRP Plan, in part due to timing considerations.)

<u>Summary</u>

In Florida, the competitive bidding rules were already in place, and it simply filed a request for determination of need with a need study. It took six and one-half months from issuance of the RFP to submit the PSC petition, and three and one-half months for the PSC to issue its decision. The approved combined-cycle unit was expected to be available three years thereafter.

In Utah, interim competitive bidding procedures were adopted by stipulation within three months of the opening of a competitive bidding docket. It took five months from the issuance of an RFP to submit a CPCN application for a phased combined-cycle unit to be used for peaking purposes, and twelve months from RFP issuance to submit a CPCN application for a base-loaded combined-cycle unit. The PSC approved the respective applications after four months and five and one-half months. The first phase (a CT) of the first combined-cycle unit was expected to be available after fifteen months, with the completion of the unit in another year. The second combined-cycle unit was expected to take two and one-half years to install.

PUC-IR-16 **(HECO)**

HECO SOP, Exhibit A at 8 states:

> The risk of project failure and reliability concerns will likely result in maintaining the requirement for parallel planning …

Exhibit A at 13, further states:

> Due to the nature of the power system in Hawaii with no outside interconnections and available options, HECO may be required to undertake a parallel planning process in case a selected project fails.

Please elaborate on the nature and extent of "parallel planning" process that would be required. What would it entail and what would be its costs, under various plausible scenarios? From whom would the costs be recovered? Would it be undertaken only in the event that a project fails, or as "backup" as the project progresses?

HECO Response:

Parallel planning would be undertaken as a backup to the primary project in case it failed to meet agreed upon implementation milestones. Parallel planning, in general, would involve planning, permitting, and engineering activities that are required to be done to preserve the ability to construct the back up power plant. Usually, these parallel planning activities involve those critical or long-lead tasks, such as permitting, that are done early in the development of power plant projects, since several major permits require public hearings and do not have mandatory time frames within which the permitting agency must act. .

For example, parallel planning would involve siting studies, unit type and size studies, and preliminary engineering work which are required to provide the necessary data and information about the power plant to support permit applications. Depending upon the power plant resource to be constructed and the site or sites being studied, the cost of this work could range from $100,000 to $750,000 or even higher.

The exact list of parallel planning activities would depend on the project specific circumstances. Environmental permits and land use approvals, if required, usually determine the critical path and overall schedule of a power plant project. Typically, the air quality permit from the Department of Health and EPA takes several years to obtain and the process must be started early in the project schedule. Parallel planning would involve undertaking those activities required to support filing and processing the application for the air permit. This would include gathering the one-year of site-specific meteorological data and background air quality data required for the permit application. These data gathering efforts take around 18 months to complete and can cost \$300,000 to \$500,000, if not higher. Completing the air permit application can cost about \$100,000 to \$250,000, depending on the complexity of the project and can take six months or longer to prepare.

Other parallel planning activities that could be undertaken would likely involve processing of the Environmental Impact Statement, Special Management Area application, land use approvals, and other long lead permits. Processing of the Underground Injection Control Permit and Water Use Permit could cost over \$100,000, depending on the complexity of the situation. Preparing and processing an EIS would cost at least \$500,000, and would take at least a year to complete.

One option is for the costs of these parallel planning activities to be recovered from the winning bidder(s) as a condition of the Power Purchase Agreement (PPA) contract. For example, as a condition of the AES Barbers Point and Kalaeloa PPAs, each party paid HECO \$955,000 to reimburse HECO for its parallel planning and preparation costs for the Kahe 7 project that these projects replaced.

PUC-IR-17 **(HECO)**

HECO SOP, Exhibit A, at 40 states:

> This [terminating negotiations and having to initiate contract negotiations with the back-up bidder] is not uncommon in the industry today in cases where the bidder is under no penalty if it decides to terminate negotiations or cancel the project.

a. Does HECO intend to impose penalties upon a bidder that decides to terminate negotiations or to cancel the project? What methods would it use to assure payment of the penalties?

b. If so, is HECO confident that it can impose sufficiently stringent penalties to provide a significant disincentive to such behavior?

c. Is there an analogy to this problem in terms of utility decision-making; e.g., is it possible for a utility in planning its own generation project to cancel a project; and if so, how would the penalty system discussed in your answer to (a) above be applied to the utility? Can such application of a penalty occur objectively if the utility is on both sides of the penalty table?

HECO Response:

a. It is difficult to impose penalties on a bidder if a bidder decides to terminate contract negotiations or cancel the project before signing the contract. Once the contract is signed the seller begins to incur obligations to meet its proposed milestone schedule leading to commercial operations. The seller also has to post security and the buyer will have access to the security if the seller defaults or fails to meet the milestones.

HECO has not yet decided if it will include contract provisions that would compensate HECO and its customers if a bidder terminates negotiations or cancels the project. In BC Hydro's recent Call for Tenders, the Company initiated a unique process whereby bidders had the opportunity to comment on the contract at various stages in the solicitation process. B C Hydro attempted to reflect the comments of the bidders in a final contract. Bidders eligible to submit a final bid were informed at the beginning of the process that if selected as the winning bidder they would be obligated to sign the Final Form

Agreement, which was not negotiable at that point. BC Hydro also required that each Tender (i.e., proposal) must be accompanied by a Tender Security in an amount equal to $10,000/Kw (Canadian Dollars) of bid capacity. The Tender Security had to be in the form of an irrevocable Letter of Credit. The Tender Security was designed to secure the obligation of the bidder to execute the contract if selected as the winning bidder. If the bidder refused to sign the contract it would forfeit the Tender Security.

b. An approach similar to BC Hydro's approach would be one solution for providing a disincentive to such behavior. The BC Hydro situation was actually similar to Hawaii. BC Hydro was soliciting bids for Vancouver Island. While the Island is interconnected with the mainland via cables, the utility felt strongly it needed to add generation on the island and imposed such a process in light of reliability concerns. Furthermore, BC Hydro informed bidders of the details of the process from the very beginning, thus ensuring that bidders knew the rules of the game before they submitted a bid.

c. The decisions of IPPs and utilities to cancel projects are not analogous, but are very different. IPPs would generally make a decision to terminate negotiations or cancel a project for the following reasons:

- The IPP bids a low price based on its estimate of the cost of equipment, interest rates, land costs, etc. and realizes through the development process that its bid price may be too low to support project financing
- The IPP has a low credit rating and may not be able secure financing on reasonable terms to allow it to complete the project under the terms bid.
- The IPP may have several projects under development and may have more economic opportunities for devoting its resources.

Utilities would most likely consider canceling a project or delaying a project if the utility forecasted that load growth would be higher than levels actually experienced and the need for the project is no longer present. Another reason for a utility to cancel a project is when there are other more economic options available. In both cases, while the utility may incur costs to develop a project, the decision to cancel will be beneficial to the customers. The IPPs decision, on the other hand, would benefit the IPP and may result in increased costs to the customer if economically attractive options are no longer available as a result of the selection of the original bidder.

PUC-IR-18 **(All parties, except HREA)**

Ref: HECO-HREA-IR-12 at 15 states:

> [Ratepayers]...will bear the risk related to...failure to obtain appropriate authorizations...

a. Who should bear the risk and associated costs of a winning bidder's failure to obtain appropriate authorizations within a specified time period - the utility, the winning bidder or ratepayers?

b. What mechanisms, if any, are available to guard against the risk of delays arising out of inabilities to obtain permits or other authorizations?

<u>HECO Response:</u>

a. The winning bidder should bear the direct risk and cost of its failure to obtain appropriate authorizations within a specified time period. The power contract may specify liquidated damages, or be subject to termination, for example, if the bidder fails to meet project milestones, or in-service date deadlines. On the other hand, project developers seek to include "outs" based on "force majeure" or the inability to obtain financing or reasonable terms. In the case of mainland utilities, liquidated damage provisions can compensate the buyer for the difference between the cost of power under the contract and the cost of power on the market if the buyer has to secure the power to replace power to be delivered under the contract, if the project developer posts enough security or is substantial enough for the damages to be collected. However, in Hawaii, with no access to a broader wholesale market, the cost to customers resulting from failure of the bidder to perform under the contract could be very high and may not be sufficient under the contract. Due to the lack of replacement power, establishing an appropriate level for liquidated damages will be more complex in Hawaii. Thus, it is more uncertain in Hawaii whether the bidder will bear the risk as it does on the Mainland.

b. As noted above, liquidated damage provisions, which are triggered if the bidder misses key milestone dates in the contract, are one mechanism for guarding against the risk of delays arising out of the inability to obtain permits or other authorizations. Contracts also generally contain a termination provision that allows the buyer to terminate the contract if the milestone date is not met after a specified cure period.

PUC-IR-19 **(All Parties)**

Ref: CA SOP at 60.

> ...an electric utility must be prepared with a "backstop" plan (i.e., the specific resources that the utility would develop and put into rate base if necessary to meet its service obligations. The backstop plan may be satisfied by the utility's resource proposals.

If a utility has a "backstop" plan that can be satisfied by its resource proposal, does this mean that it is always effectively competing with other bidders?

HECO Response:

The utility could theoretically compete at two levels. First, the utility's self-build option could be considered along with other bids submitted in response to an RFP. HECO supports the opportunity for the utility to offer a generation competing option along with other proposals. Second, the utility backstop plan could include either the utility's self-build unit that would continue to be developed until it is clear that the winning bidder will reach commercial operation, or follow an alternative plan depending on the circumstances at the time. For example, if an IPP project fails after several years of development, there may not be sufficient time to complete the utility self-build. In this case, the utility may have to install emergency diesels or smaller units to buy time while the self-build is completed.

PUC-IR-20 **HECO, KIUC)**

Ref: HECO SOP, Exhibit B at 1.

The HECO exhibit notes that PURPA requires utilities to offer to purchase capacity and energy from qualifying facilities at the utility's avoided cost.

a. If a utility is in the middle of a competitive bidding process for a specific resource requirement, and it receives an offer from a qualifying facility that meets that resource requirement, is the utility required to purchase from the qualifying facility under PURPA?

b. How do the utilities envision the competitive bid process working in conjunction with the obligations imposed on the utilities by PURPA?

<u>HECO Response:</u>

a. Competitive bidding was initiated by the states and encouraged by FERC to allow all resource options to compete. The bidding process has taken precedent in a number of states over the requirement by a utility to purchase capacity and energy from a QF under PURPA at avoided costs. Competitive bidding processes replaced the process for contracting with QFs from a cost-based approach to market-based approach and one designed to result in a greater level of benefits to customers, and were deemed consistent with FERC guidelines implementing PURPA. QFs would therefore be required to submit a bid like all other projects during a solicitation process and the utility would not be required to purchase capacity from the QF under PURPA. The utility would be obligated to purchase the energy from a Qualifying Facility at the avoided energy rate only.

b. When a utility identifies a capacity need, the utility could issue an RFP for new resources. All supply-side options will be eligible to bid, including QFs. If the QF wins the bid, it will negotiate a contract with the utility for capacity and energy at the bid price, which effectively is the avoided cost. As noted above, utilities are generally obligated to purchase power from a QF at the avoided energy rate only, and QFs who don't win the bid could sell energy at the utility's avoided energy rate. In some cases, utilities have agreed to offer standard contracts to purchase power from small QFs (e.g., projects less than 1 MW) at a price equivalent to the cost of the lowest cost winner in the utility's RFP.

PUC-IR-21 **(HECO)**

HECO SOP, Exhibit A at 2, states:

> An important benefit of competitive bidding is that all bidders and proposals participate in an organized, structured process. This is generally accomplished through a bidding process that requires all bids to be submitted at the same time, with all bidders providing complete and consistent information, with all bids being evaluated based on the same set of economic and fuel price assumptions, and with all bidders playing by the same set of rules. The evaluation of unsolicited proposals, such as traditional PURPA projects, can be complicated by different timing for proposal submission, and incomplete or inconsistent proposals.

a. Are unsolicited proposals the only alternative to a formal RFP, or is there a range of options?

b. Is HECO aware of any utilities that have invited proposals from independent power producers, without making use of a formal RFP?

<u>HECO Response:</u>

a. Yes. Based on HECO's response to PUC-IR-21(b), unsolicited proposals would be the only alternative to an RFP.

b. Any invitation for proposals can be classified as a request for proposals. The request for proposals can range from a brief notice in the newspaper or trade press of the utility's interest in purchasing power to a few pages (or a term sheet) to very detailed documents with significant information provided to bidders about the process. Some RFPs could be very unstructured (i.e., request to buy 100 MW of power during the two year period of May 2005 to April 2007) to very structured processes. Proposals for short-term and/or more standardized products can be less structured and shorter in nature, while long-term bids underlined by the construction of a new generating unit are more complex and require more consistent and detailed information from the bidder.

PUC-IR-22 **(HECO)**

HECO SOP, Exhibit A at 4, states:

> A 1996 study by the National Regulatory Research Institute (NRRI) entitled State Commission Regulation of Self-Dealing Power Transactions focused on issues associated with self-dealing and concluded that competitive bidding can limit self-dealing.

Please provide a copy of this study.

HECO Response:

The NRRI study is voluminous. Two copies of the NRRI study will be provided to the Commission, and one copy to each party or participant by separate transmittal.

PUC-IR-23 **(All Parties)**

What measures can and should be taken to avoid self-dealing or an unfair competitive advantage over other bidders (or even the appearance of such)?

HECO Response:

There are a number of steps the utility can take to avoid self-dealing or concern over an unfair competitive advantage that may be perceived by other bidders. These include:

1. The utility could submit its self-build option to the Public Utility Commission one day in advance of receipt of other bids. The utility could also provide substantially the same information as other bidders. By sending its proposal to the Commission in advance other bidders would be ensure that the utility could not adjust its bid price or project structure after reviewing other proposals.
2. The utility could establish a website devoted to disseminating information to all bidders at the same time, including the utility self-build option. All bidders would therefore have access to the same information at the same time ensuring bidders are treated fairly and equitably.
3. The utility could use an independent observer or reviewer to review the solicitation process including communications with bidders, bid evaluation and selection, and contract negotiations.
4. The utility could establish a separate project team to undertake the evaluation, with no team member having any involvement in the utility self-build option. This would serve to mitigate any potential bias towards the utility's own self-build option.

5. In several states, the utility must abide by an established Code of Conduct that dictates the obligations of the bid evaluation team. Members of the project team may be required to sign confidentiality agreements.
6. Utilities have developed Procedures Manuals to guide the process. The Procedures Manual describes the protocols for communicating with bidders, the self-build team, and others, describes the evaluation process in detail and the methodologies for undertaking the evaluation process, contains documentation forms including logs for any communications with bidders, and other information consistent with the requirements of the solicitation process.
7. The utility can develop all the evaluation criteria, bid evaluation and selection guidelines, quantitative evaluation models and other information necessary for evaluation of bids prior to receipt of bids to ensure there are no biases in the process.
8. The utility, through the independent observer, could "blind" the bids before transferring the bids to the bid evaluation team to ensure the evaluators have no knowledge of the bidders and serves to mitigate any bias that may result from knowing the bidder.

HECO could agree to most of these steps should competitive bidding be implemented in Hawaii. HECO does not think it is necessary to "blind" bids to avoid self-dealing.

PUC-IR-24 **(All Parties)**

What is the desirable outcome of this proceeding -- a specific competitive bidding procedure, a specific change to the IRP process, a specific model RFP, a specific model PPA, or anything else?

HECO Response:

As noted in its SOP at page 8, the HECO Companies have reservations about the applicability of competitive bidding to their small, isolated island systems. As described in Exhibit A to HECO's SOP at pages 4 to 14, there are a number of concerns regarding the potential shortcomings of a competitive bidding process that should be addressed before deciding to implement any competitive bidding program. The HECO Companies can support competitive bidding for certain forms of new generation, but only if it is structured in such a fashion that the potential benefits can be realized, and the potential disadvantages can be eliminated or mitigated.

Just as importantly, the process must provide for exceptions if implementing the process could negatively impact the ability of Hawaii's electric utilities to add generation in a timely fashion. Given the time that it takes to develop and implement competitive bidding processes, certain utility capacity addition projects already under development (such as HECO's planned installation of a simple cycle peaking unit at Campbell Industrial Park scheduled for installation in 2009) should not be subject to the competitive bidding process, should the process be adopted in Hawaii. Moreover, just as the IRP process has to allow for the implementation of contingency options when planning assumptions and forecasts change, any competitive bidding process would have to allow for similar exceptions.

Should the Commission decide that competitive bidding is a workable process for soliciting new generation in Hawaii, it is HECO's position that competitive bidding procedures or guidelines are a preferable solution, rather than a specific model RFP or PPA. The model

RFP and PPA will be the eventual output of the process. It is important that all participants in the process (i.e., potential bidders, the utility, customers, and other interested parties) understand the rules and guidelines underlying the competitive bidding process. In such complex processes, the "devil is in the details" and merely establishing a general framework as the CA and HREA have done in their SOP's or immediately proceeding to develop an RFP or PPA are not adequate and will likely lead to negative implications for competitive bidding, including the possibility for protracted litigation if bidders feel the rules changed or they were treated unfairly during the process.

In addition, HECO and others have recommended that competitive bidding be integrated with IRP. This may require revisions to the IRP framework and process.

PUC-IR-25 **(All Parties)**

Ref: HECO SOP at 12; CA-HECO-IR-6; HREA-HECO-IR-14.

a. Should the competitive bidding process be of a "framework" nature, i.e. a set of guidelines in the form of an enforceable Commission order (which would involve an evidentiary hearing to test the recommendations of the various parties to the proceeding)?

b. If the answer to (a) is "yes", then if the Commission does decide to initiate a proceeding to develop the competitive bidding "framework", should it hold public hearings, workshops and/or panel format hearings?

c. If the answer to (a) is "no", then should the competitive bidding process be established through a rulemaking proceeding (which would necessitate public hearings and comments)?

<u>HECO Response:</u>

a. HECO's position in the SOP is that the details of the competitive bidding process should be developed in a follow-up proceeding based on the principles enunciated by the Commission in this proceeding. HECO has expressed a preference for developing and adopting the procedures in a framework proceeding rather than in a rulemaking proceeding. Establishing a competitive bidding framework or guidelines is a preferable solution for all parties. Once the guidelines are established, "the rules of the game" for competitive bidding can be developed and will become clearer to all parties. The CA position appears to be a clear case of "Monday Morning Quarterbacking". The CA consistently states that the utility should follow industry standards but appears to leave open the option to criticize the process after the fact if they don't like the result. Establishing the guidelines or rules up front can minimize such an outcome.

b. Please refer to HECO's responses to CA-HECO-IR-6 and HREA-HECO-IR-14.

c. Not applicable.

PUC-IR-26 **(All Parties except CA)**

Ref: CA SOP at 4; HECO-CA-IR-4.

a. As advocated by the Consumer Advocate, should each utility be allowed to design its own competitive bidding process according to current "best practices," subject to commission approval?

b. How should "best practices" be determined?

c. Should the Commission provide guidelines to the utilities regarding what it considers to be current "best practices"?

<u>HECO Response:</u>

a. HECO appreciates the CA's position to allow the utilities flexibility to design its own competitive bidding process according to current "best practices". HECO does believe each utility should be able to design its own RFP, evaluation criteria, evaluation process, etc. Rather, these should be developed within the framework of competitive bidding guidelines or procedures. However, the CA has not defined what it means by "best practices" and there may be differences among the parties and potential bidders about what actually constitutes "best practices". For that reason, HECO wants to avoid the prospect for "Monday Morning Quarterbacking" that could arise from a competitive bidding process whereby others could dispute the process after it has been completed because "best practices" are undefined.

b. HECO believes that "best practices" will be developed through implementing the framework proceeding described in response to PUC-IR-25.

c. HECO believes that industry "best practices" will be reflected in the development of the details of competitive bidding guidelines. However, the "devil is in the details" and there are a number of elements associated with the development of bidding guidelines that will need to be addressed.

PUC-IR-27 **(All Parties)**

HECO SOP, Exhibit A at 34 states:

> … the development of competitive bidding rules and guidelines should be developed from the ground up without superimposing another state's system directly in Hawaii.

Is HECO aware of any state system that could profitably be used as a starting point for developing Hawaii's competitive bidding rules or guidelines, in order to reduce the cost and time required to develop them from the ground up? What aspects of such state's approach are particularly helpful?

<u>HECO Response:</u>

HECO has researched the bidding rules in a few states to gain a perspective of how they have addressed some of the key issues consistent with any competitive bidding process. Two states that may be reasonable starting points for consideration of the bidding guidelines are Oregon and Louisiana. Oregon developed its bidding rules in 1991 and there have been several solicitations undertaken under these rules, including the recent Portland General Electric RFP that has been referenced frequently in this docket. Louisiana recently developed bidding rules and utilities in the state have initiated bidding processes. Another state that recently revised its bidding rules and where recent solicitations have taken place is Florida. Also, competitive bidding has been initiated in Quebec over the past three years and the approach taken has been less formal, with the bidding procedures developed by the regulator and utility. There are a number of other states that previously developed bidding rules. Examples include Texas, Massachusetts, Minnesota, Virginia, and others. With industry restructuring and retail access, however, the competitive bidding rules in such states as Massachusetts and Texas are now obsolete.

PUC-IR-28 **(HECO)**

HECO SOP, Exhibit A, at 15 states:

> In a number of jurisdictions, the bidding guidelines were integrated with the state statutes underlying how jurisdictional utilities are regulated in the state.

a. Please indicate which states have used this approach.

b. Under what circumstances is it necessary or desirable to do so?

c. In HECO's opinion, should bidding guidelines be integrated into Hawaii statutes? Please explain your answer. If so, what legislative modifications would be required?

HECO Response:

a. Massachusetts is the primary example of a state that initiated a major regulatory process to revise its statutes to address integrated resource planning and competitive bidding. In Texas, the Texas legislature adopted revisions to legislative policies in 1995 concluding that wholesale competition among utilities and certain non-utilities is in the public interest. The Texas legislature directed the Commission to adopt such rules relating to IRP and the competitive acquisition of resources.

b. It may be necessary to undertake such a process if the legislature is adopting legislation to restructure the industry or if major restructuring efforts were undertaken that would require major changes to state statutes. Notwithstanding more extreme circumstances such as these, it is undesirable and likely unnecessary to legislate competitive bidding guidelines given, among other reasons, the rigidity of the process, the lack of expertise and focus in the legislative forum to address the multitude of detailed issues involved in competitive bidding, and the potential for over politicizing the process and its issues with the attendant risk of failure to address key issues on their merits.

c. Please see the response to subpart b above. The HECO Companies do not believe that competitive bidding guidelines should or needs to be legislated. As stated in the HECO Companies SOP at page 12, it is preferred that the details of the competitive bidding process and its procedures be developed and adopted in a framework proceeding, like that used to develop the IRP Framework, rather than in a rulemaking proceeding or in a legislative forum.

PUC-IR-29 **(All Parties except HREA)**

Ref: HREA SOP at 11-12; HREA-HECO-IR-11; HREA-KIUC-IR-1.

Please comment on the competitive bidding models offered by HREA, where the utility would identify the site, capacity, and (possibly) fuel type, then prepare and submit a "facility bidding baseline" to an independent contractor who would solicit and review bids against the utility's baseline.

HECO Response:

In addition to HECO's comments about HREA's competitive bidding models as presented in HREA-HECO-IR-11, HECO offers the following comments and observations. The models proposed by HREA differ with regard to site identification (in Model I), presentation of the utility's project costs (Model I), and the requirements that only a utility affiliate could bid (in Model II).

The Model I approach suggested by HREA whereby the utility identifies a site, the desired capacity and fuel type for the project, presents detailed cost information about the project assuming the utility constructs and operates the project, and prepares baseline cost and other information against which bidders will compete is akin to soliciting bids for a turnkey option (i.e., identifying specifications for a project at an identified site). Under the Model I approach, the potential for creative bids and different types of project options through a competitive bidding process will be eliminated. Furthermore, the publishing of detailed cost information about the baseline project may encourage bidders to bid up to the published price rather than base their price on their costs and perception of the market. The role of the Independent Contracting Agent exceeds the role generally provided by an outside party in other solicitations. Rather than "making the decision" and submitting a recommendation to the Commission, in most cases any outside party provides a review function to ensure the decisions of the utility in the evaluation and selection process is fair and unbiased. HREA's proposed role for the ICA is beyond the traditional role provided by an outside party, and HECO questions whether the risk of making such a decision and recommendation should be the obligation of the ICA. We would expect that the ICA would have to maintain a high level of professional liability insurance coverage for undertaking this role, with such costs likely passed on in the cost of compensating the ICA. In sum, the approach proposed by HREA is more applicable to short-term standard products, but has limited application for long-term resources from new generation options. The only possible application would be if a turnkey only solicitation is undertaken, but even in this case, the role of the ICA is questionable for the reasons noted above.

Model II would allow for a broader range of resource options since the site requirement and baseline cost and information requirements are not included. However, HECO has the same issues regarding the role of the ICA as noted above. Furthermore, HREA has not supported its position to only allow utility affiliate bids rather than a self-build option.