COM-HECO-DT-IR-1

HECO T-1, page 12, line 13: Provide a list of all investor-owned utilities HECO is aware of that offer DG as a utility-owned tariffed service, and copies of all tariffs that HECO has for utilities which offer utility-owned distributed generation as a tariffed service.

HECO Response:

As indicated on page 12 at line 8, a few utilities offer (or have offered) a utility ownership option for customer-sited emergency generation. Carolina Power & Light Company, doing business as Progress Energy Carolinas, Inc., offers a Premier Power Service Rider to its customers. Under the Premier Power Service Rider PPS-7A, Progress Energy supplies utility-owned and operated power generators to customers supplying capacity from 50 kW to 8 MW per site. Although the primary focus is to provide electricity to the customer's site in the event normal service is interrupted, the utility in its Premier Power Service Rider also reserves the right to dispatch the generation "to achieve system benefits, provided such dispatch does not interfere with or reduce the effectiveness of the generation to provide an alternate supply of electricity in the event normal electric supply is interrupted to the Customer." See the attached pages 2-5 for details on Premier Power Service Rider PPS-7A.

In addition (1) Duke Power requested and received approval in 2001 from the N.C. Utilities Commission of an experimental service schedule called "On-Site Generation Service" (see attached pages 6-7), (2) Florida Power Corporation requested and received approval in 2001 from the Florida P.S.C. for an Experimental "Premier Power Service Rider" (see attached pages 8-9), and (3) Madison Gas and Electric Company, in 1999, implemented a "Backup Generation Service Rider", but suspended participation by new customers in 2001 (see attached pages 10-12).

Carolina Power & Light Company
d/b/a Progress Energy Carolinas, Inc.
(North Carolina Only)

PREMIER POWER SERVICE
RIDER PPS-7A

AVAILABILITY

This Rider is available on a voluntary basis in conjunction with any of Company's general service schedules when the Customer contracts with Company to furnish certain services related to the supply of on-site generation for the primary purpose of providing an alternate supply of electric service in the event normal electric supply is interrupted. The rate schedule with which this Rider is used is modified only as shown herein.

DEFINITION OF SERVICES

Services provided under the terms of this Rider shall be provided by an on-site generator supplied and owned by Company for the purpose of continuing the supply of electricity to the Customer's site in the event the normal electric supply is interrupted. In cases where Customer's total electric requirement exceeds the generation capability of the on-site generator, Customer shall arrange its electrical requirements to ensure that the electrical requirement to be supplied when normal service is interrupted will not be greater than the on-site generation capacity. The minimum generator capacity supplied by Company under this Rider shall be not less than 50 kW; the maximum generation capacity supplied by Company under this Rider at a single site shall not exceed 8,000 kW.

All equipment installed on the Customer's premises by Company is and will remain the sole property of Company both during, and subsequent to, the Contract Term. Company reserves the right to exchange or upgrade equipment as necessary for the continued supply of these services. All equipment shall be owned, maintained, and operated solely by Company. Company reserves the right to operate the generation at all times it deems appropriate for purposes of, but not limited to, (1) testing of the generation to verify that it will operate within required parameters and (2) dispatching the generation to achieve system benefits, provided such dispatch does not interfere with or reduce the effectiveness of the generation to provide an alternate supply of electricity in the event normal electric supply is interrupted to Customer. The generation and appropriate transfer switching shall be located on Company's side of the billing meter; therefore, billing under the applicable general service schedule shall continue to be based solely upon consumption registered on Company's billing meter.

MONTHLY RATE

The Monthly Rate shall be an amount computed under the applicable general service schedule and other riders, if applicable, for the Billing Demand and kilowatt-hours registered or computed by or from Company's metering facilities during the current month plus the following:

Monthly Services Payment = Capital Cost + Expenses

where:

Capital Cost equals a carrying cost times the levelized plant investment based upon the estimated installed cost of facilities. The carrying cost includes the cost of capital, reflecting current capital structure and debt and preferred rates and the most recent approved return on common equity; income taxes; property taxes; general plant; administrative and general plant-related expenses; and intangible plant. Any replacement cost expected to be incurred during the Contract Period would also be included. Any special equipment installed by Company and not necessary to support the emergency back-up service shall not be included in the Monthly Services Payment.

Expenses shall be levelized over the Contract Term and shall include: Company operations and maintenance (O&M) expenses times a carrying cost that is inclusive of administrative and general and labor expenses related to O&M and cash working capital; third-party expenses for operations and maintenance, warranties, or insurance; fuel expense, based upon an annual estimate of fuel consumption cost, less a credit based upon the system average cost of energy included in retail tariffs; inventory cost associated with fuel, materials, and supplies times a carrying cost that recovers the cost of capital and income taxes; depreciation expense, adjusted for the estimated salvage value at the end of the Contract Period; deferred income taxes; and customer accounting, customer service and information, program administration, and sales expenses. Any expenses incurred in operating the generation, for other than normal back-up operation and testing, shall not be included in the Monthly Services Payment.

Customer shall be liable to Company for any attorney fees or other costs incurred due to Customer's failure to pay the Monthly Rate due under this Rider. Installation cost will be recovered over the initial Contract Term. Pricing of capital-related costs and expenses shall be based upon no shorter than 10 years from the equipment's original in-service date and the resulting Monthly Rate shall include an upward adjustment for Contract Terms that expire prior to 10 years from this in-service date.

CUSTOMER REQUESTED TEST

Customer may request that Company's on-site generation be operated during specific times requested by Customer. Company will comply with Customer's request provided the additional hours of operation do not adversely impact any permits or other regulatory requirements. Customer shall pay an Administrative Fee of $50 per occurrence plus the replacement cost of all fuel consumed during the test.

PREMIER POWER SERVICE AGREEMENT

Company and Customer shall execute a Premier Power Service Contract that will further state the amount of the Monthly Services Payment, as established in accordance with the Monthly Rate provision above, and the Contract Term. This Rider, in conjunction with the Premier Power Service Contract, embodies the Agreement between Company and Customer. The parties shall not be bound by or liable for any statement, writing, representation, promise, inducement, or understanding not set forth therein. In the event of any conflict between these writings and the terms of this Agreement, this Agreement shall control. No changes, modifications, or amendments to any terms and conditions in this Contract are valid or binding unless agreed to by the parties in writing by their authorized representatives.

CONTRACT TERM

The Contract Term shall be the period of time specified in the Premier Power Service Contract and shall commence with the first day service is provided under this Rider.

EARLY TERMINATION OF CONTRACT TERM

The Customer has the right to terminate this Contract before the entire Contract Term has expired. In order to terminate Contract before the end of Contract Term, the Customer must a) notify Company in writing a minimum of 60 days prior to termination of services and b) pay a Termination Fee. The Termination Fee shall be the sum of (1) the removal cost of Company's equipment and related facilities, (2) storage costs, if applicable, (3) the remaining monthly charges until such time as the Company's generator is placed in service at an alternate customer site, and (4) any initial installation cost not already received in prior monthly payments. Alternatively, the Customer may elect to pay a Termination Fee that is independent of the future use of Company's equipment. This alternative Termination Fee will be calculated by taking the sum of the Customer's payments remaining in the Contract Term, adding the removal cost, and subtracting therefrom the difference between the current salvage value and the salvage value used in setting the Monthly Rate. In the event of any termination of the Contract before the end of the Contract Term, Company shall be compensated for all services provided to Customer prior to the effective date of termination. Upon termination, Company shall remove all equipment.

PROVISIONS OF SERVICES AND INSTALLATION SCHEDULE

Company agrees to furnish labor, supervision, equipment, materials and transportation. Company shall be entitled to rely on the accuracy of any information provided by Customer, which is warranted by Customer to be accurate and correct. In the event of any unforeseen difficulties in performance of the services due to conditions at the work site or due to the inaccuracy of any information relied upon by Company, the Monthly Rate, description of services, and Contract Term shall be equitably adjusted to compensate for any additional work. Company shall exercise reasonable efforts to complete the services within any schedule specified in the Premier Power Service Contract. Any schedule that is specified in the Contract is only an estimate of the time it will take to complete the services. In the event of any unforeseen difficulties in performance of the services due to conditions at the work site or due to the inaccuracy of any information relied upon by Company, the Customer shall indemnify Company for any costs or expenses incurred by Company and the compensation payable to Company, the description of services, and the schedule for the subject services shall be equitably adjusted to compensate for any additional work Company may be required to perform.

CUSTOMER'S RESPONSIBILITIES

Customer shall provide a location on premise for installation of Company's facilities and any necessary access to the work site, as well as reasonable lay-down area to perform the services. Any additional services that become necessary because of inadequate access to the work site shall be grounds for an equitable adjustment in the schedule and the Monthly Rate. Company shall have the right to suspend services or adjust the schedule accordingly in the event that there is inadequate access to the work site, or if any required information is not promptly provided, or in the event that the safety of any person or property might be jeopardized by continuing with the services. Customer shall provide, at no cost to Company, any plans, specifications, drawings, or information that may be necessary or useful in the performance of the services. Customer will ensure that all Occupational Safety and Health Act requirements are adhered to for the area where any Company equipment, in support of the services, is to be stored. In the event of damage to Company-owned equipment that is caused by the Customer or Customer's agents, Customer agrees to pay all repair or replacement costs associated with the damage.

PERMITS AND REGULATORY REQUIREMENTS

Company shall be responsible for obtaining any license or permit required of Company in Company's name to enable it to provide the services. Customer assumes the risk and responsibility for such compliance or change, or for securing such permits, licenses, and approvals from the proper authorities, and for paying any associated costs or fees should compliance with any laws, rules, regulations, or ordinances of any federal, state, or local authority, or of any agency thereof (including, but not limited to, certification to do business as a foreign corporation) require any changes in the services; or should any permits, licenses, or approvals of plans and specifications for the services or should any permits, licenses, or approvals for the installation or use thereof be required.

LIMITATION OF LIABILITY

Neither Company nor its employees, its subcontractors, or suppliers shall be liable for any direct, indirect, general, special, incidental, exemplary, or consequential loss or damage of any nature arising out of their performance or non-performance hereunder. This provision shall apply whether such liability arises in contract, tort (including negligence), strict liability, or otherwise.

INSURANCE

Company represents and warrants that it has met all requirements under North Carolina law with regard to workers' compensation and automobile liability coverage. Company is self-insured for workers' compensation, automobile liability, and general liability coverage.

FORCE MAJEURE

In no event shall Company be responsible for any damages arising out of any failure to perform or delay due to any cause beyond Company's reasonable control. In such event, Company shall be entitled to an extension of time as necessary to overcome the cause of the failure to perform or delay.

USE OF SUBCONTRACTORS

Company shall be permitted to use subcontractors to perform the services. Notwithstanding the use of subcontractors, Company shall continue to be responsible for the quality of the services.

NON-WAIVER

The failure of either party to insist upon the performance of any term or condition of this Agreement or to exercise any right hereunder on one or more occasions shall not constitute a waiver or relinquishment of its right to demand future performance of such term or condition, or to exercise such right in the future.

WARRANTY

Company warrants that services shall be performed in accordance with generally accepted industry practices. The Warranty set forth above is exclusive, and no other warranty or remedy of any kind, whether statutory, written, oral, express, or implied, including without limitation warranties of merchantability and fitness for a particular purpose, or warranties arising from course of dealing or usage of trade shall apply. Except as provided in the Use of Subcontractors provision above, Company shall not be responsible for any work done by others or for any loss, damage, cost, or expense arising out of or resulting from such work, unless authorized in advance by Company.

REGULATORY AUTHORITY AND GOVERNING LAW

Services rendered under this Agreement are subject to the authority of the North Carolina Utilities Commission and any changes or other modifications lawfully made thereto. This Agreement shall also be governed by the laws of the State of North Carolina, except that the North Carolina conflict-of-laws provisions shall not be invoked in order to apply the laws of another state or jurisdiction.

SALES AND OTHER TAXES

To the above stated charges will be added any applicable North Carolina Sales Tax. The Monthly Rate for the services are subject to revision for future changes in sales or use tax, or any future tax upon or measured by the gross receipts for any transaction hereunder or any allocated portion thereof, or similar charge with respect to the services. If Company is required by applicable law or regulation to pay or collect any such tax or taxes on account of these services rendered under this Agreement, then such amount of tax and any penalties and interest thereon shall be reimbursed to Company. Any such change in the Monthly Rate shall be subject to prior approval by the North Carolina Utilities Commission.

Supersedes Rider PPS-5
Effective for services rendered on and after July 10, 2003
NCUC Docket No. E-2, Sub 720

ON-SITE GENERATION SERVICE PROGRAM (NC)
Pilot

AVAILABILITY (North Carolina only)

The program is available, at the Company's option, to nonresidential customers receiving concurrent service on Schedules G, GA, I, OPT, PG or HP.

PROGRAM

Under the terms of this program, the Company will own, install, operate and maintain an on-site generator designed to provide a supply of electricity to the Customer's facility in the event that the normal supply of electricity is interrupted. In addition, the Company reserves the right to operate the generator at times when the supply of electricity has not been interrupted to the Customer's facility and thereby provide a source of capacity to the utility system. The minimum size generator provided under this program will have a nameplate rating of 300 KW. The generator and associated equipment will be located on the Customer's premises at a mutually agreed upon location. The Customer will be billed for all usage registered on the Company's billing meter under the applicable rate schedule.

RATE

The monthly rate for this service will be determined as follows:

Monthly Services Payment = Levelized Capital Cost + Expenses

Where:

Levelized Capital Cost is equal to the present value of all estimated capital related cash flows for a period corresponding to the time of engineering, design and installation of equipment through the term of the contract, adjusted to a pre-tax amount and converted to a uniform monthly payment for the term of the contract. The estimated capital cash flows shall include installed cost of equipment, contingency allowances, property taxes, salvage value, adjustment to reflect additional supporting investment of general plant nature, and income tax impacts.

Expenses shall equal the present value of estimated expenses associated with the support and maintenance of the generation and equipment, adjusted to a pre-tax amount and converted to a uniform monthly payment for the term of the contract. The estimated expenses shall include administrative and general expenses, expenses for labor and materials related to operations and maintenance, third party expenses for operations and maintenance, warranties, insurance, annual costs associated with working capital, fuel inventory, other costs related to the operation and support of the generator installation, and income tax impacts.

The after tax cost of capital from the Company's most recent general rate case will be used to convert present values to uniform monthly payments.

(On-Site Generation Service Program (NC) continued)

PAYMENT

Bills for service under this program are due and payable on the date of the bill at the office of the Company. Bills are past due and delinquent on the fifteenth day after the date of the bill. All bills not paid by the twenty-fifth day after the date of the bill shall be subject to a one percent (1%) late payment charge. This late payment charge shall be rendered on the following month's bill and it shall become a part of and due and payable with the bill on which it is rendered.

CONTRACT PERIOD

Each customer shall enter into a contract for On-Site Generation Service from the Company for an original term of ten (10) years, or other term at the Company's option, and thereafter from year to year upon the condition that either party may terminate the contract at the end of the original term by giving at least ninety (90) days previous notice of such termination in writing. In the event of early termination of a contract under this program, the Customer will be required to pay the Company any costs due to such early termination.

RATE SCHEDULE PPS-1
GENERAL SERVICE - PREMIER POWER SERVICE RIDER
(EXPERIMENTAL)

Availability:

Available throughout the entire territory served by the Company.

Service under this experimental schedule must be requested before July 24, 2006, unless extended by order of the Florida Public Service commission.

Applicable:

This Rider is applicable on a voluntary basis to a Customer with a minimum measured demand of 200 kW taking service under general service rate schedules GS-1, GST-1, GSD-1, GSDT-1, or GSLM-1 when the Customer contracts with Company to own, install, operate and maintain generation on the Customer's premises for the primary purpose of providing a back-up supply of electric service in the event normal electric supply is interrupted. The applicable general service rate schedule with which this Rider is used is modified only as required by the terms hereof.

Character of Service:

Continuous service, alternating current, 60 cycle, single-phase or three-phase, at the Company's standard distribution voltage available.

Limitation of Service:

Standby or resale service not permitted hereunder. Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations Governing Electric Service."

Monthly Service Payment:

The Monthly Service Payment under this Rider is in addition to the monthly rate determined under the applicable general service rate schedule and other riders, if applicable, and shall be calculated based on the following formula:

Monthly Service Payment = Capital Cost + Expenses

Where:

Capital Cost equals a carrying cost times the levelized plant investment based upon the estimated installed cost of facilities. The carrying cost includes the cost of capital, reflecting current capital structure and most recent approved return on common equity; income taxes; property taxes; general plant; administrative and general plant-related expenses; and intangible plant. Any replacement cost expected to be incurred during the Contract Period will also be included. Any special equipment installed by the Company that is not necessary to support back-up service to the Customer shall not be included in the Monthly Service Payment.

Expenses shall be levelized over the Contract Term and shall include: Company operations and maintenance (O&M) expenses times a carrying cost that is inclusive of administrative and general and labor expenses related to O&M and cash working capital; third-party expenses for operations and maintenance, warranties, or insurance; fuel expense, based upon an estimate of the cost of fuel consumed for normal back-up operation and testing, less a credit based upon the system average cost of fuel and purchased power included in retail tariffs; inventory cost associated with fuel, materials, and supplies times a carrying cost that recovers the cost of capital and income taxes; depreciation expense, adjusted for the estimated salvage value at the end of the Contract Term; deferred income taxes; and customer accounting, customer service and information, program administration, and sales expenses. Any expenses incurred in operating the on-site generation for other than normal back-up operation and testing shall not be included in the Monthly Service Payment.

Installation cost will be recovered over the initial Contract Term. Pricing of capital-related costs and expenses shall be based upon no shorter than 10 years from the equipment's original in-service date and the resulting Monthly Service Payment shall include an upward adjustment for Contract Terms that expire prior to 10 years from this in-service date.

(Continued on Page 2)

Florida Power
A Progress Energy Company

RATE SCHEDULE PPS-1
GENERAL SERVICE - PREMIER POWER SERVICE RIDER
(EXPERIMENTAL)

(Continued from Page 1)

Definition of Services:

Services provided under the terms of this Rider shall be provided by an on-site generator supplied by the Company for the purpose of continuing the supply of electricity to the Customer's site in the event the normal electric supply is interrupted. In cases where the Customer's total electric requirement exceeds the generation capability, the Customer shall arrange its electrical requirements to ensure that the electrical requirement to be supplied when normal service is interrupted will not be greater than the generation capacity. The minimum generator capacity supplied by the Company under this Rider shall be not less than 200 kW.

The Company shall have the right to operate the on-site generator at all times it deems appropriate, including, but not limited to, for the purposes of testing of the generator to verify that it will operate within required parameters, and dispatching the generator to assist in meeting system demand. The generator and appropriate transfer switching shall be electrically connected on the Company's side of the billing meter; therefore, billing for generation provided during normal back-up operation and testing shall continue to be billed under the applicable general service rate schedule based solely upon consumption registered on the Company's billing meter.

Minimum Monthly Bill:

The minimum monthly bill shall be the Customer's minimum bill under the applicable general service rate schedule, plus the Monthly Service Payment under this Rider.

Terms of Payment:

Bills rendered hereunder are payable within the time limit specified on bill at Company-designated locations.

Term of Service:

Service under this Rider shall be for the term specified in the Premier Power Service Contract.

Service Contract:

The Company and the Customer shall execute a Premier Power Service Contract that will state the amount of the Customer's Monthly Service Payment determined in accordance with this Rider, the Contract Term, and other terms and conditions pertinent to providing Premier Power Service.

2nd Revised Sheet No. E 40

MADISON GAS AND ELECTRIC COMPANY Amendment No. 271

ELECTRIC VOLUME 2

Backup Generation Service Rider - Pilot Program	Rate Schedule **BGS**

Effective in: All territory served.

AVAILABILITY

Service under this voluntary schedule is available to customers on demand-metered rate schedules Cg-1 Level B, Cg-2, Cg-4 Level B, Cg-6, Sp-3, and Sp-4 who contract for service for an initial period of three years or more. Participation in this program will be limited to a 50 MW total customer load. R

RATE

All the provisions of the applicable Cg-1, Cg-2, Cg-4, Cg-6, Sp-3, and Sp-4 rate schedules shall apply. In addition:

A. Customers taking firm service under this schedule will have an additional charge for backup service applied to the customer maximum 15-minute demand as identified below; and

B. Customers taking interruptible or supplemental service will have an additional charge for backup service applied to the minimum contract firm demand level as identified below:

- For diesel-fueled generators, $1.50 per kW per month
- For natural gas-fueled generators, $3.50 per kW per month

CONDITIONS OF DELIVERY

1 A customer receiving service under this rider must enter into a contract that identifies the size of the generator specified and installed by the Company and the customer's expected annual maximum load.

2. A customer that receives electric service through more than one distribution service feed at a single location (premise) may choose to take backup service under this schedule for all or only some of the service feeds at that location. The Company may require the customer to pay in advance of installation for any additional metering or measurement equipment necessary for the customer to take backup service for less than the entire premise.

For firm service customers, backup generation service must be taken for the entire load at each distribution service chosen. For purposes of this schedule, the customer maximum 15-minute demand shall be the greatest rate at which electrical energy has been used for the distribution service feeds chosen during any 15 consecutive minutes in the current or preceding 11 billing months.

Issued: April 19, 1999

Next Page is Sheet No. E 40.01

Effective: April 15, 1999

PSCW Authorization: By letter dated April 15, 1999; File No. 3270.

MADISON GAS AND ELECTRIC COMPANY

ELECTRIC VOLUME 1

Backup Generation Service Rider - Pilot Program	Rate Schedule **BGS**

Effective in: All territory served.

CONDITIONS OF DELIVERY (continued)

For interruptible and supplemental service customers, backup generation service must be taken for the full amount of the customer's minimum contract firm demand level. For purposes of this schedule, the contract firm demand level shall be the customer's contract firm demand level in effect at the time the customer enters into the BGS contract with the Company. N N N N

3. The contract will have an initial term of three or more years. At the end of the initial term the contract will be automatically renewed on an annual basis unless written notice from either party is delivered to the other party no later than 180 days prior to the end of the contract term.

4. The authorized rate in effect at the time the initial contract term begins for a customer will remain fixed for that customer for the entire initial contract term, regardless of other changes that may from time to time be approved by the Public Service Commission of Wisconsin. At the end of the initial term, service will be charged at the authorized rate in effect at the time.

5. The Company will work with the customer to determine where to install the generator and associated equipment. The facilities will comply with Wisconsin State Electrical Code, local ordinances, and accepted engineering and planning practices and will be connected to the Company's system over the most direct route as determined by the Company. The Company is responsible for maintaining facilities in compliance with applicable regulations and ordinances that may change over the term of the contract.

6. The customer will provide or will be responsible for the cost of all right-of-way easements and building permits necessary for the Company to connect the generator to the Company's system and to install, maintain, or replace distribution facilities where necessary.

7. The customer will supply the space for the generator and a concrete pad as specified by the Company. The customer will either clear and grade such property and pour the pad or pay the Company to clear and grade such property and pour the pad.

8. The Company is responsible for installation and backfilling as necessary. The customer is responsible for the cost of restoration of the property after the Company has completed installation and backfilling where applicable.

Issued: April 8, 1999

Next Page is Sheet No. E 40.02

Effective: March 19, 1999

PSCW Authorization: By letter dated March 17, 1999; File No. 3270.

MADISON GAS AND ELECTRIC COMPANY Amendment No. 259

ELECTRIC VOLUME 1

Backup Generation Service Rider - Pilot Program	Rate Schedule **BGS**

Effective in: All territory served.

CONDITIONS OF DELIVERY (continued)

9. If the generator installation requires nonstandard service facilities or if the customer requests nonstandard facilities or design, including but not limited to aesthetics, noise attenuation, exhaust ventilation, or location on the customer's premise, the Company shall require the customer to pay a contribution in advance of construction for the cost of the facilities in excess of standard design.

10. The customer will be required to make the Company equipment available and permit entry upon the property by Company personnel at reasonable times for the purposes of testing, maintenance, and replacement of the equipment. The Company will be responsible for testing the generator at least once a year to ensure the equipment is in proper working condition.

11. The Company reserves the right to operate the generator to meet system load requirements.

12. The availability of service under this schedule may be limited at the discretion of the Company. Service under this schedule may be refused if the Company believes the customer presents an unacceptable credit risk or cannot provide or meet suitable generator siting requirements, including physical and environmental restrictions and liability limitations.

13. Service under this schedule shall be furnished only in accordance with the Electric Service Rules and Regulations of the Company.

14. Energy furnished under this schedule shall not be resold by the Customer.

COM-HECO-DT-IR-2

HECO T-1, page 16, line 12: Provide any numerical examples the Companies have prepared of how non-participating customers would be affected by customer-sited DG that is NOT company-owned, versus the impact of customer sited DG that IS company owned.

HECO Response:

As stated on page 17 of HECO T-1, the Companies performed an extensive quantitative economic analysis in support of its CHP Program application in Docket No. 03-0366 considering all the numerous revenue and cost impacts, to show that the Companies' ratepayers are better off with utility-owned DG. (See HECO T-3, page 10, line 16 to page 12, line 7.)

COM-HECO-DT-IR-3

HECO T-1, page 16, line 22: What is the "uniqueness" characteristic of the Company's offering? Provide any analyses that have been prepared by the Company supporting that "uniqueness."

HECO Response:

The uniqueness of the Companies' CHP offering is to provide a complete utility-owned, operated, and maintained CHP unit to the customer. Customers have responded well to such a model as it relieves them of the responsibilities of owning, operating, and maintaining the CHP equipment themselves, or subcontracting those responsibilities out. While other CHP developers have offered and may continue to offer third-party system ownership benefits to customers, the general trend has been for the CHP equipment vendors and energy service companies to move away from the model of owning equipment at a customer site. In addition, utility-owned CHP would be subject to oversight by the Public Utilities Commission, and this provides reassurance to CHP customers that the CHP systems will be properly designed, operated, and maintained.

COM-HECO-DT-IR-4

HECO T-1, page 18, line 1: Provide the workpapers showing that Castle and Cooke Resorts contribute $1.2 million per year to MECO's fixed costs.

HECO Response:

The workpaper showing the breakout of Castle & Cooke's contribution to fixed costs was filed as Exhibit II to MECO's Application for Approval of a Service Contract with Castle & Cooke Resports, LLC in Docket No. 03-0261. See the attached Exhibit II.

Maui Electric Company, Limited

Castle & Cooke Resorts 2002 kwh Sales and Revenues
and
Fixed Cost Portion of Base Electric Revenues

Accounts	2002 kwh sales	base electric revenue	energy portion of base electric revenues	fixed cost portion of base electric revenues
Schedule G (6 accounts)	301,212	$ 64,240	$ 27,614	$ 36,626
Schedule J (9 accounts)	2,240,340	$ 494,635	$ 206,404	$ 288,231
Schedule P (2 accounts)	8,923,600	$1,690,227	$ 805,264	$ 884,963
Total (17 accounts)	11,465,152	$2,249,102	$1,039,282	$1,209,820

COM-HECO-DT-IR-5

HECO T-1, page 21, line 18: Provide any numerical analysis of how the utility's fixed cost of owning and maintaining DG systems compares with the fixed cost recovery the Company would receive for these projects under its existing tariff rates.

HECO Response:

The Companies have not done the analysis requested. However the appropriate analysis would consider all of the costs and revenue impacts, as was considered in the CHP program analysis.

As discussed in the CHP program application, if the Companies loses sales due to a Companies loses sales due to a DG vendor's CHP system or DG project, the Company loses revenue based on the reduction in demand charges (due to the reduction in monthly peak demand, if any), and the reduction in energy charges, and saves the variable operating and maintenance costs associated with that part of the customer's reduction in load and energy. Since the energy charge recovers a substantial percentage of the Company's fixed demand and customer costs, the lost revenues far exceed the saved costs. All else being equal, other customers (non-participating ratepayers) have to pick up the difference.

If the Company installs a utility CHP system instead, it retains the demand and energy charge revenues from the sale of electricity (less the reduction, if any, in energy usage and demand due to the use of waste heat to displace electricity, and less the price reduction to reflect the benefits of customer-sited generation); it gains revenues from the sale of waste heat (therms) and from the facilities charge for the absorption chiller (if an absorption chiller is included in the project); and it incurs the capital, operating and maintenance costs for the CHP system installation.

All of these revenue and cost impacts were considered in the quantitative economic analysis of the CHP Program for each Company. Thus, discounts in the electricity price, the therm price, and the facilities fee, were explicitly considered. Similarly, the revenues that a Company continues to receive from a customer for supplemental or backup service provided under its regular rate schedules if a DG vendor does the project also are explicitly considered.

When the Companies actively pursue their respective CHP Program after it is approved, they fully expect the rate of CHP system installations to be accelerated. The Companies would not simply be displacing CHP system and/or DG installations that might have been installed by a non-utility vendor, such as Hess or others, but will be adding to the number of CHP system installations. The costs of "incremental" CHP system projects have to be compared against costs avoided by the Companies (through capacity addition deferrals, if any, and through non-generation by and non-transmission of the energy from central station generation.)

In the case of the CHP Program, both effects are expected to be present and were analyzed in the quantitative economic analysis of each Company's program.

COM-HECO-DT-IR-6

HECO T-1, page 22, line 19: Provide any numerical analysis the Companies have prepared comparing how the utility's fixed cost recovery under current tariffs compares with the estimated fixed costs of acquiring additional generation capacity for MECO, HECO, and HELCO.

HECO Response:

With regard to the estimated fixed costs of acquiring additional generation capacity, the testimony in HECO T-1, page 22, lines 19 through 23 (as referenced in the IR), stated that a generic CHP unit was defined for practical purposes. The fixed operations and maintenance ("O&M") costs for these generic CHP units are estimated to be $0/MW-Yr for HECO, HELCO, and MECO. For the purposes of the CHP evaluation, all O&M costs were considered dependent upon the CHP's run hours and were therefore considered variable. These cost assumptions are illustrated in the CHP Program, Docket No. 03-0366, Workpaper H, page 8 (HECO), page 27 (HELCO), and page 48 (MECO). The Companies did not prepare a numerical analysis which attempted to isolate and compare fixed O&M costs for the generic CHP units against current tariffs.

COM-HECO-DT-IR-7

HECO T-1, page 26, lines 7: Provide copies of all non-utility CHP vendor proposals.

HECO Response:

The Companies do not have direct access to non-utility CHP vendor proposals, as those proposals are between the non-utility CHP vendor and the customer. The Companies' are generally familiar with the offerings of non-utility vendors based on discussions with the customers and with Hess.

COM-HECO-DT-IR-8

HECO T-1, page 26, line 20: The Company seeks to offer DG systems at a "discount" to the normal tariff. What other services does the Company offer on a "value of service" rather than "cost of service" basis?

HECO Response:

The Companies provide electric energy services in accordance with Commission-approved tariffs which generally are based on cost of service. The proposed pricing for CHP systems consists of more than a "discounted" electricity price – it includes a facilities fee, a thermal charge and an electricity price. The total price was developed taking into account the cost of providing CHP systems, as in indicated on pages 24-31 of the CHP Program Application, so that non-participants should be better off if the utility provides the service. (See response to COM-HECO-DT-IR-2.)

COM-HECO-DT-IR-9

HECO T-1, page 26, line 20: Provide any internal analyses the Company has prepared of the "cost" to provide DG service as it is anticipated.

HECO Response:

The analyses were conducted and submitted in support of the Companies CHP Program application in Docket No. 03-0366. (See HECO T-3, page 10, line 16 to page 12, line 7.)

COM-HECO-DT-IR-10

HECO T-1, page 26, line 20: Provide copies of all operating protocols that the Companies have developed relating to the operation of customer-site DG systems, and how these would affect the Company's generation, distribution and transmission capacity requirements and associated costs.

HECO Response:

The Companies have not yet developed protocols for operation of customer-sited DG. Please see the response to CA-IR-13 for general description of the control logic dispatch that is being considered.

COM-HECO-DT-IR-11

HECO T-1, page 31, line 12: Provide copies of all proposals made by the Company to customers to install DG equipment.

HECO Response:

As stated in response to LOL-SOP-IR-82, "the Companies object to providing documents regarding ... communications done by or on behalf of the Companies with respect to engaging in the CHP or DG business or responding to competition, on the grounds that: (1) such documents contain proprietary commercial and financial information, and the disclosure of such confidential information on a public basis or to entities engaged in the sale of competing services could adversely impact the Companies' transactions with customers, adversely impact the Companies' costs of doing business, and result in higher costs to ratepayers; (2) the uncontrolled disclosure of proprietary information would give providers of competitive services information useful in making their own marketing decisions, without expending the time and money necessary to gather and develop the data, and would allow providers of competitive services to profit or otherwise derive benefits at the expense of the Companies and their ratepayers; (3) requests that the Companies produce 'all' documents are overly broad and unduly burdensome given the volume of documents (including e-mails, agendas, power point presentations, etc.); (4) information produced pursuant to such requests could include preliminary and/or outdated analyses, which have been superceded by later analyses that are more relevant to the subject-matter of this proceeding; and (5) many of the documents contain information that is protected by the attorney-client privilege and/or the attorney work product privilege."

"The Companies also object to the production of customer-specific information on the grounds that (1) such information is confidential and has been protected from disclosure by the

Commission in other proceedings, (2) in some cases, the customer specific information is already subject to a protective order in another docket, and (3) the disclosure of such information has not been consented to by the customers."

However, as stated in response to LOL-SOP-IR-82, the Companies are willing to make the MOUs and LOIs available to the Commission ("PUC"), the Consumer Advocate ("CA"), the Parties, and the Participants under an appropriate protective order, although customer specific information may have to be redacted from copies made available to persons other than the PUC and CA if the definition of Qualified Persons is not restrictive enough. A list was provided as part of HECO's response to LOL-SOP-IR-82.

The Companies are in the process of compiling a list of current customer proposals. Once the list is compiled, it will be provided to the PUC and parties. The Companies are willing to make the listed documents available to the PUC and CA under an appropriate protective order, but continue to object to providing such documents to other parties and participants (and will determine whether to continue such objection after the definition of Qualified Persons in the Protective Order for this proceeding is determined). Proposals that result in agreements will be documented and submitted to the Commission for approval, and the information in such executed agreements will be made available (with the exception of the final thermal charge and any proprietary customer information, subject to a protective order in the approval docket).

COM-HECO-DT-IR-12

HECO T-1, page 32, line 3: Provide documentation of all payments made to Hess Microgen in association with its teaming agreement with Hess Microgen?

HECO Response:

HECO has made only one payment to Hess Microgen, LLC ("Hess") in the amount of $5,200.

This payment was for a three-day technical training session given by Hess to HECO and HELCO representatives in Carson City, Nevada in February 2004.

COM-HECO-DT-IR-13

HECO T-1, page 33, line 4: Provide a list of all vendors other than Hess the Company has had discussions with, any copies of any packaged system summary cost and technical information provided by all such vendors. This should not exceed twenty pages of information per vendor.

HECO Response:

In its consideration of developing a new CHP procurement process, the Companies have had discussions with Hawthorne Pacific, formerly Pacific Machinery, in addition to Hess. The discussions concerned basic objectives of the process (as stated in HECO T-1, page 32) and not detailed offerings of the vendor, as that would have been premature given the process is still being formulated by the Companies. The Companies anticipate issuance of a request for qualifications ("RFQ") by the end of August, 2004. The RFQ will be sent to Hess, Hawthorne Pacific, and other vendors of CHP equipment. Upon receiving responses to the RFQ, the Companies will have available the cost and technical information of the vendors. The Companies' ability to provide data from the responses to parties in this docket will be depend on the extent to which the information received is deemed to be confidential and proprietary by the vendors.

COM-HECO-DT-IR-14

HECO T-2, page 5, line 4: Provide any studies HECO has prepared or received that estimate the capacity value of photovoltaic installations without storage backup systems on any utility system.

HECO Response:

HECO has not prepared any studies nor is HECO aware of studies that estimate the capacity value, if any, of photovoltaic installations without storage backup systems on any utility system.

COM-HECO-DT-IR-15

HECO T-2, page 14, line 20: Provide any studies HECO has prepared or received that estimate the capacity value of wind turbines without storage backup systems on any utility system.

HECO Response:

HECO has not prepared any studies that estimate the capacity value of wind turbines without storage backup systems on any utility system.

In Docket No. 00-0135 (Apollo Energy Corporation Petition), one of the issues pertained to capacity payments for the Apollo windfarm on the Island of Hawaii. Issue No. 1 in Prehearing Order No. 17804 was "[w]hether the proposed HELCO-Apollo Power Purchase Agreement ("PPA") should include a provision for capacity payments to Apollo, and if so, what capacity payments should be included in a HELCO-Apollo PPA?" In the Rebuttal Testimony of Mr. Thomas A. Wind on behalf of Apollo Energy Corporation[1], Mr. Wind indicated that "[a] rough estimate of this firm capacity from the existing wind turbines would be 2 MW. If the wind farm is repowered to 9.75 MW (7 MW maximum instantaneous) as proposed by Apollo, then I would estimate the firm capacity value to be 3 MW. If the Kamao'a Wind Farm is then expanded up to the 20 MW level (15 MW maximum instantaneous), then the firm capacity value would be about 6 MW."[2] Mr. Wind used a Midcontinent Area Power Pool ("MAPP") procedure for estimating the capacity value but acknowledged that "Kamao'a's historical hourly generation was not available to me; therefore, I could not calculate the equivalent firm capacity."[3]

HELCO's position was that "HELCO should not pay capacity payments for wind energy based on accredited capacity determined through the MAPP capacity accreditation

[1] Filed on September 15, 2000.
[2] Apollo RT-2, page 8, line 19, to page 9, line 3.
[3] Apollo RT-2, page 8, lines 17 and 18.

process. While an accredited capacity number can be derived from the MAPP methodology, that number cannot be equated with a firm capacity amount that HELCO could rely upon to fulfill its long-term obligations to provide firm power to its customers. In practice, even if an accredited capacity number can be calculated for a resource, consideration must be given to the output characteristics of the resource and whether or not a small, isolated electric utility should rely on this number for long-term capacity planning purposes. It would not be prudent to rely on an accredited capacity number for intermittent as-available energy generators to defer the construction of new capacity because the HELCO system is not interconnected with other utilities and thus cannot rely on neighboring utilities to provide needed capacity in the event as-available resources do not produce the amount of power needed at the time needed."[4]

In Decision and Order No. 18568, dated May 30, 2001, the PUC stated, "The commission does not believe that capacity payments for Apollo are warranted. Rather, HELCO, under its generation capacity planning criteria, is unable to avoid or defer the construction of its own generation additions as a result of the intermittent energy generated by a wind farm such as Kamaoa. Nor is HELCO able to avoid the fixed operations and maintenance costs associated with its own generation."

The commission continued "The wind resource used by Apollo to generate energy is as-available. The generation of energy by wind farms such as Apollo is ultimately dependent upon the availability and strength of this resource. Apollo, the commission finds, is not under a continual obligation to supply power to HELCO upon demand."[5]

[4] Testimony of Ross Sakuda, HELCO RT-2, page 18, line 21, to page 19, line 9.
[5] Section III.A, page 4.

COM-HECO-DT-IR-16

HECO T-2, page 14, line 20: provide any studies HECO has prepared or received that estimate the impact on system loss of load probability resulting from application of as-available generation such as wind or photovoltaic systems without backup storage systems.

HECO Response:

HECO has not prepared any studies that estimate the impact on system loss of load probability resulting from application of as-available generation such as wind or photovoltaic systems without backup storage systems. See also HECO response to COM-HECO-DT-IR-15.

COM-HECO-DT-IR-17

HECO T-2, page 19, line 1: Provide any studies HECO has prepared or received since January 1, 2000 relating to the availability and/or cost-effectiveness of specific wind installations located on the island of Maui.

HECO Response:

See HECO-201, pages 3 and 12, for information on HECO's various wind initiatives. In November 2003 Hawaiian Electric Industries, Inc. ("HEI"), the parent company of HECO, HELCO and MECO, prepared a Windfarm Economic Analysis for Hawaii comparing utility vs IPP ownership of windfarms. The analysis is an internal management report. HECO and HEI object to providing the confidential analysis on the grounds that it contains confidential, proprietary information and public disclosure of the information could be used to the competitive disadvantage of the company. HECO also objects to providing the document on the grounds that it is an internal management report. Requiring internal strategic management assessments to be subject to review by parties in a regulatory proceeding would have a "chilling" effect on such analysis. Were these analyses be subject to review in a regulatory proceeding, their candid nature and, therefore, their value would diminish significantly in the future, and the Companies' internal analysis processes would be seriously hampered. HECO would object to disclosure of the internal management report even under protective order. The value of internal management reports will be diminished if HECO is required to provide the reports, even if the documents were provided under protective order.

COM-HECO-DT-IR-18

HECO T-3, page 4, line 2: Provide any quantification the Company has prepared of the generation, transmission, and distribution costs that a DG installation could avoid on the island of Maui.

HECO Response:

Please refer to the Companies' CHP Program application, filed on October 10, 2003, Docket No. 03-0366, Exhibit H, pages 13 to 16. Please also refer to Workpaper H, pages 40 to 56, filed with the Commission on November 13, 2003, Docket No. 03-0366. Please also refer to HECO's responses to COM-HECO-DT-IR-2 and COM-Companies-SOP-IR-4.

COM-HECO-DT-IR-19

HECO T-3, page 5, line 13: Provide any analysis of the differences in avoided costs the Companies would experience depending on whether DG systems were company-owned or customer-owned. Include all assumptions as to operating protocols, short-run variable costs, fixed costs, and other parameters that lead to differences in these costs.

HECO Response:

As stated in HECO T-3, page 9, lines 20 to 22, "no differentiation was made between utility and non-utility CHP with respect to their firm capacity ratings and their ability to defer firm central-station capacity." In reality, there appears to be differences, but the Company has not performed an analysis to quantify the differences, given the numerous factors (for which data and/or experience is not available) needed to make such an analysis. Please refer to HECO T-3, page 9, line 10, to page 10, line 12.

COM-HECO-DT-IR-20

HECO T-3, page 8, line 5: Provide the estimated cost per kw for acquiring additional generation, transmission, and distribution peaking capacity for MECO, compared with the estimated cost per kw of acquiring customer-sited DG systems under the Company's proposed program.

HECO Response:

As indicated in HECO's response to COM-Companies-SOP-IR-11, the estimated cost for Waena Unit 1 (a nominal 20 MW simple cycle combustion turbine), including escalation and AFUDC in 2010 dollars is $70.5 million. As indicated in Exhibit G, page 3, of the Companies' CHP Program application, in Docket No. 03-0366, the estimated CHP capital cost for MECO in 2003 dollars is $1,598 per kW. If escalated to 2010 dollars at 3% per year, this would be equivalent to about $1,960 per kW. However, it must be noted that the cost per kW of the central station unit cannot be directly compared to the cost per kW of the CHP unit for various reasons, including (1) the central station unit has a higher level of redundancy built into it whereas the CHP unit would be backed up by the utility grid for electrical power and by the customer's existing heating equipment for thermal energy; (2) the cost of the central station unit includes the cost of combustion turbine spare parts, a 1 MW black start diesel engine, an Uninterruptible Power Supply, a spare water treatment train, and redundant water and fuel pumps; (3) the central station unit will produce its own process water from groundwater whereas the CHP units will need to draw from the County water supply through the customer's existing infrastructure; and (4) the Waena CT has the capability to be included in an efficient combined-cycle unit in the future, and its consideration for the next central station unit for MECO's system would take into account this potential.

Moreover, comparing the cost per kW of acquiring peaking capacity with the cost of acquiring customer-sited DG systems (actually, CHP systems) under the Company's proposed program is of limited utility. Analyses of all relevant cost and revenue factors, such as the analysis done for the program application, are more useful. See response to COM-DT-IR-2.

COM-HECO-DT-IR-21

HECO T-3, page 8, line 18: Provide the estimated cost and technical specifications for the proposed CHP installation on Lanai discussed in the testimony.

HECO Response:

MECO is in preliminary discussions with Castle & Cooke Resorts on the location and configuration of the proposed CHP system. The CHP project proposal will be presented to Castle & Cooke and the Manele Bay Hotel for their approval, then submitted to the PUC for regulatory review and approval prior to any procurement or construction on the CHP project.

MECO previously preformed an analysis for a proposed CHP system at Manele Bay in the 2003 timeframe. This analysis was preliminary and the CHP system was different than the system currently being proposed. MECO, with assistance from HECO, is in the process of evaluating the size, configuration and fuel type for a proposed CHP system for the Manele Bay Hotel. The CHP units being considered are in the 350 – 450 kW size range, two unit configuration, an absorption chiller of about 150-ton capacity, and domestic hot water heating capability. MECO will consider the use of propane and diesel fuel for these units. The project cost estimate will be developed following the determination of CHP system size, configuration, and fuel type.

COM-HECO-DT-IR-22

HECO T-3, page 11, line 8: Provide any analytical documents prepared by or for the companies indicating what characteristics of customer-owned DG make them as-reliable or less-reliable than Company-owned resources.

HECO Response:

HECO does not understand the basis for this question. There is nothing in the section of the testimony cited by the County of Maui that pertains to "characteristics of customer-owned DG [that] make them as-reliable or less-reliable than Company-owned resources".

In any case, for the purposes of the avoided cost analysis in the Companies' CHP Program in Docket No. 03-0366, both utility and non-utility CHP units were assigned the same Forced Outage Rates and Equivalent Availability Factors. See also response to COM-HECO-DT-IR-19.

COM-HECO-DT-IR-23

HECO T-3, page 12, line 7: Please re-run the analysis showing relative present value of revenue requirements assuming that the same level of penetration of DG occurs with and without utility involvement.

HECO Response:

HECO does not have this analysis. Further, HECO objects to this information request on the grounds that it would be unduly burdensome, taking take several weeks to perform this work. In accordance with Prehearing Order No. 20922, at page 5, a party "...shall not be required, in a response to an information request, to make computations, compute ratios, reclassify, trend, calculate, or otherwise rework data contained in its files or records." For HECO's plans with respect to its IRP-3 CHP evaluation, see HECO T-3, pages 13-14.

COM-HECO-DT-IR-24

HECO T-3, page 15, line 9: Provide all documents that recorded or estimated the grid impacts from large customers running their backup generators and disconnecting from the grid when requested by HECO, MECO, or HELCO in an emergency.

HECO Response:

In system emergencies, the utilities may request that customers voluntarily reduce their demand. However, the utilities do not request that customers disconnect from the grid, even if they have emergency generators. A customer's emergency generator generally covers only a few critical loads such as elevators and hallway lighting. They therefore do not want to be disconnected from the system. If the system emergency is great enough, the customer will be disconnected either via underfrequency relay or by switching to protect the system.

The utilities do not have a means to verify or quantify actual load reductions achieved. It is not possible to determine what system peak reduction was actually achieved solely from requested voluntary load reductions because many factors simultaneously serve to reduce coincident peak demand in such circumstances.

COM-HECO-DT-IR-25

HECO T-3, page 15, line 18: Provide any information HECO has on the air permitting problems experienced by other electric utilities that have developed DG programs utilizing customers' backup generators.

<u>HECO Response:</u>

HECO does not have such information.

COM-HECO-DT-IR-26

HECO T-4, page 9, line 2: Explain how T&D reliability is enhanced by a CHP system, specifically considering the risk of an unscheduled outage of the CHP system. Indicate how the Company probabilistically measures changes in expected outages given that unscheduled outages are rare, but inevitable.

HECO Response:

The testimony should be clarified , since a single CHP system generator would be subject to both scheduled maintenance outages (which potentially could be scheduled for off-peak periods) and forced outages, See HECO T-4, pages 13-15. However, the Companies' CHP Program application in Docket No. 03-0366 proposed a generic configuration of installing two units for CHP systems, which improve the reliability of the CHP system compared to a single unit installation. Two CHP units will allow an outage (either scheduled or unscheduled) of one CHP unit while allowing continued partial waste heat recovery output. HECO T-4, pages 5-9 explains the T&D planning process and the options that are considered in resolving planning criteria violations or reliability concerns. CHP systems can increase the reliability of the Companies' T&D systems by reducing the load served by the T&D systems on a continuous basis. Reducing the load served by the T&D systems will reduce the current flow and could defer the need to install transmission facilities to address criteria violations. CHP systems can also increase the reliability of the customer's electricity service by providing power at the location of the customer without using the Companies' T&D systems.

The Companies do not probabilistically measure changes in expected outages when planning the T&D system. The Companies generally study the more probable contingency situations for T&D planning. In addition, considering unscheduled outages will be done on a case-by-case basis depending on what is being planned for and the circumstances (including the number of

CHP/DG systems), the outage characteristics of the CHP systems (mainly the overhaul and scheduled maintenance outages) and the relative sizes of the CHP systems.

COM-HECO-DT-IR-27

HECO T-4, page 16, line 1: Exactly what do you mean by "a little more control" and indicate what elements would need to be included in a third-party or customer-owned CHP standby agreement in order to provide equal "control" to that asserted here.

HECO Response:

"A little more control" refers to the control inherent in direct ownership over a CHP system, which allows the utility to anticipate problems, deal with them proactively and control the facility. HECO T-4, page 16 lines 1-14 and HECO T-3, page 9, lines 22 to page 10, lines 9 explains why the utility would have more control over the facility. Operational and reliability issues such as those explained in HECO T-3, pages 16-17, hypothetically could be addressed in agreements between CHP owners and the utility. The HECO standby rider, for example, has a maintenance scheduling option. Standby agreements (and/or interconnection agreements) are not intended to address the manner in which a DG unit is maintained. (Even in firm capacity agreements, which do require maintenance coordination and good engineering and operating practices to be followed, and do provide for dispatch of the IPP facility, the utility's control of the facility is never equivalent to the control offered by utility ownership.) See also the response to HREA-HECO-T-4-IR-4.

COM-HECO-DT-IR-28

HECO T-4, page 22, line 12: Assume hypothetically that a continuous-duty CHP system were installed at a location where loads range from 50% to 90% of existing transmission system capacity, reducing loads to no more than 70% of rated capacity. Because of limited load growth expectations, no transmission upgrade is anticipated, and so there are no anticipated capital cost deferrals. Describe in general terms how the CHP system installation at such a location would affect line losses on this transmission circuit, given that loads on the line at peak periods would decline significantly.

HECO Response:

For this example, it is assumed that the CHP system reduces the load, which uses 90% of the transmission system capacity to a level where it uses only 70% of the transmission system capacity. Losses in the case where only 70% of the line capacity was used would be reduced because less power would be flowing through the transmission system than in the case where the load demand was 90% of the line. In order to determine the amount of loss reduction from a CHP system, the amount of losses at several system load levels (typically 5-7 load levels), which represents the 50% to 90% load range would be calculated using the PSS/E load flow program described in HECO T-4, pages 5 and 20. A second set of load flows would take into consideration how the CHP system reduces the 50% to 90% loads, for instance, a CHP system could reduce the 50% load level to 40% and the 90% load level to 70%. Several points along the 40% to 70% load range would be simulated and losses would be calculated by the PSS/E load flow program. The two cases would then be compared to find the reduced loss amount or what is referred to as the avoided losses.

COM-HECO-DT-IR-29

HECO T-5, page 2: Explain how an embedded cost of service study provides a meaningful guide to the costs avoided or incurred by the Company if a customer installs a DG system.

<u>HECO Response:</u>

A cost-of-service study is a tool used to determine the cost responsibility of the different rate classes served by the utilities for ratemaking purposes. The embedded cost-of-service study is a tool or process used to categorize and allocate the utility's total revenue requirements of providing service among the various rate classes to determine each rate class' cost responsibility. The embedded cost-of-service study is based on total system costs and may not provide a meaningful guide to the costs avoided or incurred by the Company if a customer installs a DG system. The impact of a customer DG on the system facilities is relatively location-specific (i.e., it depends on where the DG is located/installed), and the system embedded costs are not broken down by location.

COM-HECO-DT-IR-30

HECO T-5, page 7: Assume hypothetically that the company serves 10 DG customers with 15 MW of DG equipment, but diversity that produces an expected maximum coincident peak standby demand on the Company of 3 MW. Explain how the Company would address diversity of standby demands among multiple DG customers in establishing a production and transmission allocation factor for these customers, were they to be treated as a separate class.

HECO Response:

The Companies' embedded cost-of-service study currently uses the Average-Excess Demand Method (AED Method) to allocate the production and transmission demand costs. In the past, HECO also prepared the Peak Responsibility Method to allocate the production and transmission demand costs and the results were compared with the AED Method. If the Companies determine that the deployment of distributed generation warrants reevaluating other demand allocation methods to use in addition to or in place of the current methods used in the Companies' embedded cost study, the Companies will do so. Such reevaluation of other demand allocation methods would have to take into consideration factors such as the availability of the required data.

COM-HECO-DT-IR-31

HECO T-5, page 7: Assume hypothetically that the company serves 10 DG customers with 15 MW of DG equipment, but contract provisions restricted these customers from receiving standby service at times when system reserves were below specified levels, and therefore their expected maximum coincident peak standby demand on the Company would be zero MW. Explain how the Company would establish a production and transmission allocation factor for these customers, were they to be treated as a separate class.

HECO Response:

See HECO response to COM-HECO-DT-IR-30.

COM-HECO-DT-IR-32

HECO T-5, page 7: What elements of the marginal cost study are relevant to the consideration of DG in Hawaii, and how would the presence of DG systems affect marginal costs for Hawaii utilities as measured by HECO.

<u>HECO Response:</u>

The relevance of any element of the marginal cost study in the "consideration of DG in Hawaii" depends on how the information will be used. The marginal cost study provides estimates of the three cost components – marginal demand costs, marginal energy costs, and marginal customer-related costs. Which one of these costs is relevant depends on how the information will be used.

The Companies do not have information and have not done any analysis or study on how the presence of DG systems affects marginal costs for Hawaii utilities.

COM-HECO-DT-IR-33

HECO T-5, page 7: Provide the complete workpapers for the most recent marginal cost of service studies prepared for MECO, HECO, and HELCO.

HECO Response:

The workpapers for the most recent marginal cost studies for MECO, HECO, and HELCO were filed in Docket No. 97-0346 (1999 test year rate case), Docket Nos. 7700, 7766, and 02-0405 (1994 and 1995 test year rate cases, and docket to establish HECO's Rider EDR – Economic Development Rate), and Docket No. 99-0207 (2000 test year rate case), respectively. The requested information is voluminous, and is available for inspection at HECO. Please contact Dan Brown with HECO's Regulatory Affairs at 543-4795.

COM-HECO-DT-IR-34

HECO T-5, page 9: The testimony states that the load factor block method is "widely used" in the industry. Provide a list of all utilities other than the HEI utilities that use load factor blocks that the Company is aware of, and provide copies of the relevant tariffs for these utilities.

HECO Response:

The list of utilities with load factor block rate form that the Companies are aware of is provided below. The tariff sheets are voluminous. Please contact Dan Brown at HECO's Regulatory Affairs at 543-4795 to arrange for inspection.

Alabama
Alabama Power - Rate LPL: Light and Power Service- Large
Rate LPEL: Restricted Light and Power Service (Alternate)

Arizona
Arizona Public Service Company - Schedule E-32

California
Southern California Edison - Schedule GS-2

Connecticut
Connecticut Light and Power Company - Rate 35

Georgia
Georgia Power Company - Schedule PLM-3
Schedule PLM-2
Schedule PLL-2

Savannah Electric - Schedule IP-8

Kentucky
American Electric Power - Tariff M.G.S (Medium General Service)

Minnesota
Otter Tail Power Company - Rate Designation C-02M

Mississippi
Entergy Mississippi - Rate Schedule GS-295
Rate Schedule B-31

Mississippi Power - Rate Schedule LGS-33
Rate Schedule LGS-EH-26

Missouri
Union Electric Company - Service Classification No. 3 (M)

New Jersey
Atlantic City Electric Company - Rate Schedule AGS-Secondary
Rate Schedule AGS-Primary

New Mexico
Public Service Company of New Mexico - General Power Service - TOU Rate

New York
New York State Electric and Gas - Service Classification No. 2
Service Classification No. 3

Orange and Rockland Utilities - Service Classification No. 3

Ohio
Allegheny Power - Schedule "C"

Oklahoma
Public Service Company of Oklahoma - Schedule PL-4
Schedule PL-5
Schedule GS-4
Schedule GS-5

Pennsylvania
Citizens' Electric Company of Lewisburg - Schedule GLP-1
Schedule GLP-3

Duquesne Light Company - Rate GMH

PECO Energy Company - Rate GS

Pennsylvania Power Company - Rate Schedule GS

Pike County Light & Power Company - Service Classification No. 2

PPL Electric Utilities - Rate Schedule GS-1
Rate Schedule GS-3
Rate Schedule LP-4
Rate Schedule LP-5
Rate Schedule LP-6

UGI Utilities, Inc. - Rate GS-4

West Penn Power Company - Schedule 40
Schedule 41
Schedule 46

South Dakota
MidAmerican Energy Company - Schedule GDD

Texas
West Texas Utilities Company - Rate GS

Virginia
The Potomac Edison Company - Schedule "C"

Virginia Electric and Power Company - Schedule GS-2

West Virginia
West Virginia Power - Schedule LGS

COM-HECO-DT-IR-35

HECO T-5, page 9: The testimony states that the load factor blocks are a proxy for time-of-use pricing. Provide copies of all studies prepared by or for HECO that examine substitution of time-of-use pricing for the current load-factor blocks.

HECO Response:

The Company does not have studies that examine the substitution of time-of-use pricing for the current load-factor blocks.

COM-HECO-DT-IR-36

HECO T-5, page 9: Assume hypothetically that a customer has an individual noncoincident peak demand of 100 kw at 10 A.M., a 70% load factor (500 kwh/kw), and their demand at the system coincident peak at 6 P.M. is 60 kw.

a. Does the Company agree that this customer would be in the second load factor block for any decision to use more or less power at 6 P.M.?

b. Does the Company agree that if the customer used more power at 6 P.M. this power use would increase the system coincident peak demand?

HECO Response:

a. HECO is not clear what statement in HECO T-5, page 9, the information request is referencing or related to. However, based on the hypothetical assumptions provided in the information request, the hypothetical customer would be in the third load factor block for all additional consumption regardless of the time of consumption.

b. HECO is not clear what statement in HECO T-5, page 9, the information request is referencing or related to. However, any increase in a customer's demand coincident with the system peak would increase the system peak, assuming all things equal.

COM-HECO-DT-IR-37

HECO T-5, page 10: How many of the Schedule P and Schedule J customers on each of the system have meters that are capable of measuring time-of-use for demand and/or energy (including programming and memory upgrades, but not meter replacements).

HECO Response:

The requested information is as follows:

	HECO	HELCO	MECO
Schedule J	1,045	166	117
Schedule P	306	51	102
Total	1,351	217	219

COM-HECO-DT-IR-38

HECO T-5, page 13: Provide any quantification of the loss of net revenue available to serve residential customers that MECO, HECO, and/or HELCO would suffer if customer DG installations occur, taking into account the rate design and the marginal costs faced by each utility.

HECO Response:

The Company has not quantified the loss of net revenue that MECO, HECO, or HELCO would experience if customer DG installations occur, because the amount of lost revenue is dependent upon the amount of energy sales displaced by the DG systems. The Companies performed economic analyses in support of their CHP Program application in Docket No. 03-0366 considering all the numerous revenue and cost impacts. The analyses included what could be the impact on ratepayers if a third party installed and owned the CHP system instead of the utility. See the CHP Program application, pages 51-61, and Exhibit H.

COM-HECO-DT-IR-39

HECO T-5, page 13: Does the Company concede that in most wholesale markets on the mainland, pricing is done for market transactions on a time of use energy basis, with no separately stated demand charge? In this situation, would you concede that all fixed generation costs, if recovered, are recovered in energy rates? Provide any analysis of this situation prepared by the Company which relates to its discussion of recovery of fixed costs in energy rates.

HECO Response:

The Company is not clear what statement in HECO T-5, page 13, the information request is referencing or related to. The Company does not have information as to whether or not "most wholesale markets on the mainland" do pricing on a "time of use energy basis with no separately stated demand charge". The Company is not clear what "situation" is referred to for which analysis is requested "which relates to its discussion of recovery of fixed costs in energy rates". Under the Companies' current rate structures, a significant level of the demand costs are included in the energy charges. Thus, to the extent there are lost energy charges, the contribution to fixed costs is lost. Presuming that "this situation" that is being referenced in this IR is the situation where "in most wholesale markets on the mainland, pricing is done for market transactions on a time of use energy basis, with no separately stated demand charge", the Companies do not have any analysis of "this situation" prepared by the Companies.

COM-HECO-DT-IR-40

HECO T-5, page 14: If revenue losses from customer self-generation is lower than Company marginal costs, would you agree that customer self-generation reduces rate pressure on other customers?

HECO Response:

The current rate structure is designed to recover a large portion of fixed embedded costs in the energy rate. As such, any reduction in kWh sales due to customer self generation would result in a loss of the recovery of a portion of the fixed embedded costs which would have to be shifted to the other ratepayers.

COM-HECO-DT-IR-41

HECO T-5, page 16: The company states that wheeling is not an issue in this proceeding. If a customer has more than one business location, and had DG opportunities at one or more of those locations, would a customer not be interested in wheeling as a means to serve multiple locations for consumption from fewer locations for generation?

HECO Response:

As stated in HECO T-5, page 15, lines 21 to 23, wheeling is not within the scope of the instant proceeding. HECO cannot speculate as to a given customer's interest or motive with respect to the wheeling of power from one location to another location.

COM-HECO-DT-IR-42

HECO T-5, page 17: Provide the complete methodology and workpapers that the Company has developed for allocating standby service costs to the customers that would be served by the Company-owned CHP systems proposed in the CHP docket. If no methodology has been developed, provide all memoranda, analyses, and calculations that bear on this subject that have been produced by the companies. If this is different from the HELCO Schedule A methodology, provide all analysis supporting the difference(s).

HECO Response:

The requested information is not available. The Company has not developed a methodology or workpapers for allocating standby service costs to the customers that would be served by Company-owned CHP systems. HELCO's last general rate proceeding (Docket No. 99-0207) contains information regarding standby service costs that have been produced by the Companies.

COM-HECO-DT-IR-43

HECO T-5, page 17: Provide all underlying analysis for the statement that HELCO's rates exceed HELCO's marginal costs.

HECO Response:

See attached. Also see HECO response to COM-HECO-DT-IR-33.

Hawaii Electric Light Company, Inc.
Summary of Embedded Costs & Marginal Cost By Rate Class

	Embedded Costs		
Rate Class	Rev Requirement @ Proposed ($000s)	Rev Requirement @ Full Cost ($000s)	Marginal Cost ($000s)
	A	B	C
Schedule R	$73,451.5	$79,136.8	$97,646.0
Schedule G	$19,930.8	$19,519.9	$16,686.1
Schedule J	$44,032.9	$41,429.7	$36,559.0
Schedule H	$4,661.5	$4,774.7	$3,729.6
Schedule P	$36,446.1	$33,682.4	$26,904.7
Schedule F	$738.0	$717.3	$539.3
Total	$179,260.8	$179,260.8	$182,064.6

Source:
Col. A - HELCO Transmittal letter dated February 13, 2001, Attachment D, Page 7, Docket No. 99-0207.
Col. B - HELCO Transmittal letter dated February 13, 2001, Attachment D, Page 8, Docket No. 99-0207.
Col. C - HELCO Transmittal letter dated February 13, 2001, Attachment D, Page 11, Docket No. 99-0207; and Docket No. 99-0207, HELCO-R-1808.

COM-HECO-DT-IR-44

HECO T-5, page 19: If the Company's CHP application is approved, will the Company withdraw it's Rule 4 Customer Retention Rate Contract provision?

HECO Response:

See HECO T-5, page 20, lines 17-21. The Company has not made any determination regarding HECO and HELCO's Rule 4 Standard Form Contract for Customer Retention tariff provision.

See also HECO response to CA-IR-34.

COM-HECO-DT-IR-45

HECO T-5, page 19: The Company states that the customer retention rate discounts are less than the class subsidies. It also states that it has such a contract on Lanai. However, Exhibit 501 shows that all classes on Lanai are receiving subsidies. Please explain how this is logically consistent.

HECO Response:

As stated in HECO T-5, page 19, beginning line 18, the Rule 4 Standard Form Contract for Customer Retention rate is only in effect for HECO and HELCO. The HECO and HELCO customer retention rate discounts were set at amounts less than or equal to the subsidy borne by the rate class (HECO and HELCO's Schedules J and P).

MECO does not have a Rule 4 Standard Form Contract for Customer Retention rate. The referenced statement on the basis of the HECO and HELCO's Rule 4 Standard Form Contract for Customer Retention does not apply to MECO's service contract with Castle & Cooke. The terms of MECO's service contract with Castle & Cooke were the result of negotiations between the parties. See MECO Response to CA-IR-1 in Docket No. 03-0261.

The justification for the discount to Castle & Cooke Resorts is addressed in the application filed on September 17, 2003 in Docket No. 03-0261. The Consumer Advocate in its Statement of Position indicated, based on its review that the discount is reasonable. The Commission found in Decision and Order No. 20811 that the discount to Castle & Cooke Resorts is reasonable and in the public interest, particularly in light of potential loss of revenues to MECO and the impact on the remaining ratepayers, and approved the contract.

COM-HECO-DT-IR-46

HECO T-5, page 20: The proposed CHP contract has a proposed a "termination charge" if customers terminate service prematurely. Explain why this should not be required of all large system supply customers, not just CHP customers.

HECO Response:

The Termination Charge in the Companies' proposed CHP Agreement is designed to allow the Company to recover its CHP project costs from the customer, in the event that the CHP customer terminates service for any of the reasons specified in Term & Condition No. 5.4. The proposed CHP Program provides facilities to serve specific customers as opposed to system facilities. While the Companies' current tariffs do not explicitly provide for termination charge for all large customers, there are certain tariff provisions that allow recovery of the Companies' costs of serving specific customers. These tariff provisions include the following:

1. Rule 13 provides a mechanism for the Companies to recover some of the costs of connecting new customers to the system by allowing them to charge customer advances.
2. Rule 4.B allows the Companies to require service contracts to customers with large loads requiring the Company to make substantial investment in facilities to serve the load. The Companies may specify termination charge in such contracts which require PUC approval.
3. The current load management Riders I, M, and T have termination charge provisions.

COM-HECO-DT-IR-47

HECO 501, P. 5: Does the subsidy shown for the Schedule P class on Lanai include or exclude the payment being made by MECO for customer retention? If it does not include this, please recast the exhibit showing the effect of this payment.

HECO Response:

Please see HECO T-5, page 12, lines 7-11, for the definition of the subsidy shown in HECO-501. Also see HECO response to COM-HECO-DT-IR-45 regarding the basis of the customer retention rate discount provided in MECO's contract with Castle & Cooke. Further, HECO objects to this information request on the grounds that, in accordance with Prehearing Order No. 20922, at page 5, a party "...shall not be required, in a response to an information request, to make computations, compute ratios, reclassify, trend, calculate, or otherwise rework data contained in its files or records."

COM-HECO-DT-IR-48

HECO T-6, page 4, line 22: Provide the current estimate of the cost of construction and integration of the next peaking capacity generating unit for HECO.

HECO Response:

The current estimate (in 2004 dollars) for construction and integration of a nominal 107 MW peaking unit into the HECO system is $110 million, including AFUDC. This equates to a unit cost of about $1,030/kW and includes planning, permitting, material and construction of the following items:

- One Combustion Turbine with Stack
- Water Treatment Facilities
- Waste Water Treatment Facilities
- Fuel Oil Storage and Berm
- Step-Up Transformer
- Administration Building
- Warehouse
- Emergency Generator
- Water Supply and Injection Wells

As HECO is in the initial phases of this project, the current cost estimate is considered to have an accuracy of plus or minus 20%, which should not be considered sufficiently accurate for submittal of a PUC application. Also, see response to COM-HECO-DT-IR-20.

COM-HECO-DT-IR-49

HECO T-6, page 4, line 22: Provide the current production net plant in service, and the generating capacity of the generating units represented by that capacity. If the Company has data indicating the net plant in service of units under contract (AES/BP and Kalaeloa) and the capacity represented by those units, provide that data.

HECO Response:

The production net plant-in-service (total cost less accumulated depreciation) for HECO, including steam production and other production plant, as of December 31, 2003, was $163,982,842. The total net capacity of HECO's generating units is 1,208 MW.

HECO does not have plant-in-service data for the non-utility generating units AES Hawaii, Kalaeloa and H-Power. The generating assets for those facilities are owned by other parties and are not reflected in HECO's balance sheet.

COM-HECO-DT-IR-50

HECO T-6, page 4 line 22: Does the Company concede that the marginal capital cost of new generating capacity for HECO significantly exceeds the current average capital cost of generating facilities now serving HECO customers, and that, other things equal, addition of a new power plant will therefore cause upward rate pressure?

HECO Response:

The capital cost of new generating capacity exceeds the average depreciated capital cost of existing HECO generating facilities that are in rate base. (The capital costs of firm IPP generation generally are included in levelized capacity payments, which are expense items.) Additions of new generating plant to rate base tend to cause upward rate pressure, at least initially. It should be noted, however, that Maalaea Unit M19 was installed in September 2000 and MECO has not increased its base rates. In addition, rates are based on all costs, and not just rate base. In some cases, new generation may have lower fuel costs.

COM-HECO-DT-IR-51

HECO T-6, page 8, line 6: Provide any tariff provisions that prevent customer-sited emergency generators from being allowed to interconnect with the grid, as long as all interconnection requirements are met?

HECO Response:

This category (customer-sited emergency generation) assumes that the generation is not operated in parallel with the grid, so that no interconnection agreement is required. For customer-sited emergency generators to be allowed to operate in parallel with the utility electric system, customers must execute an interconnection agreement and comply with the provisions of the interconnection technical requirements included in the Companies' respective Rule 14.H. If the generators are operated in parallel with the grid, then the seventh DG category applies.

COM-HECO-DT-IR-52

HECO T-6, page 10, line 25: Provide documents of all past Commission and court rulings relating to the retail sale of electricity by non-utility companies in Hawaii.

HECO Response:

The Companies object to a request that they do legal research on behalf of the County. Without waiving this objection, please see the responses to TGC/HECO-SOP-IR-14 and CA-SOP-IR-14.a.

COM-HECO-DT-IR-53

HECO T-6, page 12, line 18: Provide information showing how the provision of a non-monopoly service, such as CHP, is a natural step in the evolution of the natural monopoly services of electric utilities?

HECO Response:

As stated in HECO T-1 (HECO T-1 page 27), and as addressed in the Companies' CHP Program application, the Companies believe that offering CHP is a natural evolution of electric utility services. The Companies have used DG sited at substations to address transmission and generation capacity requirements. As utilities, they have long been in the business of installing, operating, and maintaining generating units, and the electric utility can readily apply this experience to customer-sited CHP systems. Moreover, to the extent that the CHP systems can play a broader role in the utility electrical system, it is even more natural for the utility to be directly involved in developing and owning CHP.