Hawaiian Electric Company, Inc.

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EDUCATIONAL BACKGROUND AND EXPERIENCE

Business Address:	Hawaiian Electric Company, Inc. 820 Ward Avenue P. O. Box 2750 Honolulu, HI 96840
Position:	Director, Generation Planning Power Supply Planning & Engineering Department
Education:	Bachelor of Science in Mechanical Engineering University of Hawaii, 1978
Other Qualifications:	Registered Professional Engineer Hawaii Mechanical Branch - 1983
Experience:	<u>HAWAIIAN ELECTRIC COMPANY, INC.</u> April 2000 to Present Director, Generation Planning Power Supply Planning & Engineering Department Hawaiian Electric Company, Inc. November 1999 - March 2000 Project Manager Power Supply Planning & Engineering Department August 1995 - October 1999 Senior Planning Engineer Power Supply Planning & Engineering Department 1993 - July 1995 Senior Mechanical Engineer Power Supply Planning & Engineering Department

Experience (cont'd):

1990 - 1992
Project Manager
Engineering Department

October 1983 - 1989
Mechanical Engineer
Engineering Department

November 1979 - September 1983
Mechanical Designer
Engineering Department

NAKASHIMA ASSOCIATES
April 1979 - October 1979
Mechanical Designer

Other Curriculum:

Corporate Training Course
Zenger-Miller Supervision Course
Utility Finance and Accounting Course

Previous Testimony:

Hawaii Electric Light Company, Inc.
Apollo Energy Corporation Petition
Docket No. 00-0135

Hawaii Electric Light Company, Inc.
Request for Approval of Rate Increase
Test Year 2000
Docket No. 99-0207

Hawaiian Electric Company, Inc.
Waiau Water Agreements
Docket No. 7277

Engineering Standard Practice

Section V - Generation Planning

Subsection B, Part 11.1

Subject: Capacity Planning Criteria for Addition of Generation in HECO Long-Range Expansion Studies

Date: August 18, 1997

Cancels: December 11, 1990

Summary of Changes from Previous Issue:

1) New capacity planning criteria are based on the following policy statement regarding the treatment of interruptible loads in capacity planning:

   "Future power plant unit additions will not be planned or constructed to serve underfrequency relay-controlled interruptible loads. Such loads will be served by the reserve generating capacity that must be planned, constructed and dispatched in order to provide adequately reliable service for regular rate, firm customers."

2) Generating unit ratings were changed from gross unit capabilities to net unit capabilities.

3) Generating unit emergency ratings were eliminated.

DEFINITIONS

1. Available Unit
   Unit which is capable of providing service, whether or not it is actually in service, regardless of the capacity level that can be provided.

The following definitions specify how the generating unit kilowatt ratings shall be used in long-range generation expansion studies for determining the requirement dates for generation additions to the HECO system.

2. Normal Gross Capability Rating: (G_1, G_2, G_3 . . . G_N)
   These ratings shall not exceed the generator nameplate maximum KVA rating under any condition.

   a) For applicable steam turbines this is the maximum gross load the unit is capable of carrying continuously on a day-to-day basis with valves wide open, 5 percent overpressure, normal temperature, and all feed water heaters in service. This is the maximum gross load to which the unit is normally dispatched.

   b) For combustion turbines this is the gross output at the base temperature control capability.

3 Normal Net Capability Rating: (N_1, N_2, N_3 . . . N_N)

   a) For applicable steam turbines this is the maximum net load the unit is capable of carrying continuously on a day-to-day basis with valves wide open, 5 percent overpressure, normal temperature, and all feed water heaters in service. This is the maximum net load to which the unit is normally dispatched.

   b) For combustion turbines this is the net output at the base temperature control capability.

When purchases of firm capacity are made by HECO from other suppliers, these sources may be represented as generating units with normal gross and net capability ratings determined to be at reasonable levels which are consistent with the intent of these definitions.

GENERATION ADDITION RULES

New generation will be added to prevent the violation of any one of the rules listed below. Available units include available HECO and firm capacity supplier units.

1. The sum of the normal net capability ratings of all available units minus the normal net capability rating of the largest available unit must be equal to or greater than the system peak load (as measured at the high-voltage side of the generator step-up transformers, i.e., before T&D losses) to be supplied at 60 Hz, minus the total amount of underfrequency relay-controlled interruptible loads

$$\sum_{i=1}^{n} N_i - N_L \geq \text{System Net Peak Load - Interruptible Load}$$

where N_L = normal net capability rating of largest available unit.

2. There must be enough net generation running in economic dispatch so that the sum of the three second quick load pickup power available from all running units, not including the most heavily loaded unit, plus the net loads of all other running units must equal or exceed 95 percent of the hourly system net load (which excludes power plant auxiliary loads but includes T&D losses). This is based on a minimum allowable system frequency of 58.5 Hz and assumes a 2 percent reduction in load for each 1 percent reduction in frequency.

The preceding rules apply to capacity planning in long-range generation expansion studies. The actual commercial operation date for the next unit to be added shall be determined using these rules as guides, with due consideration given to short-term operating conditions, equipment procurement, construction and financial constraints.

GENERATION RELIABILITY GUIDELINE

Capacity planning analysis will include a calculation of risk (Loss of Load Probability) in years per day for each year of each plan of the long-range expansion study. In cases where risk is calculated to be less than 4.5 years per day, the plan will be reviewed by the Vice President of Power Supply and the President for approval of use of the plan in the study. Calculations of risk will utilize normal net capability ratings (N_1, N_2, N_3 . . . N_N).

Approved: Tom Joaquin, Vice President
Power Supply

Sep 3 97
Date

Approved: T. Michael May, President &
Chief Executive Officer
Hawaiian Electric Company, Inc.

10/8/97
Date

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ENGINEERING STANDARD PRACTICE	SECTION: V SYSTEM PLANNING	SUBSEC B	PART 14.1	PAGE 1/3
	SUBJECT: Capacity Planning Criteria for Addition of Generation HELCO Long-Range Expansion Studies	DATE: December 4, 2003		
		CANCELS: January 22, 1997		

The following specifies how various generating unit kilowatt ratings are to be used in longrange generation expansion studies for determining the requirement dates for generation additions to the HELCO system. The latest approved load forecast will be used.

Generating units shall be given the following kilowatt ratings, where applicable, for use in determining generation addition requirement dates to the HELCO system. None of these ratings will exceed the generator nameplate maximum kva rating at rated power factor, under any condition.

1. Normal Top Load Rating: (A_1, A_2, A_3 . . . A_N)
   a. For steam turbines, this is the maximum load the unit is capable of carrying continuously on a normal day-to-day basis with valves wide open, normal pressure, normal temperature, and all feed water heaters in service. This is the maximum load to which the unit is normally dispatched.
   b. For combustion turbines, this is the base temperature control capability, which is the maximum load the unit is capable of carrying continuously on a day-to-day basis.
   c. For diesel units, this is the maximum design capability, which is determined by the manufacturers recommendations and operating conditions.

2. Reserve Rating: (B_1, B_2, B_3 . . . B_N)
   a. For applicable steam turbines this is the maximum load the unit is capable of carrying continuously on a day-to-day basis with valves wide open, 5 percent overpressure, normal temperature, and all feed water heaters in service.
   b. For combustion turbines this is the base temperature control capability, which is the maximum load the unit is capable of carrying continuously on a day-to-day basis.
   c. For diesel units less than 2.5 MW normal top load rating, the reserve rating will be the same as the normal top load rating. For diesel units, 2.5 MW and larger, this is the two hour, 10 percent overload capability.

3. Emergency Rating: (C_1, C_2, C_3 . . . C_N)
   a. For applicable steam turbines, this is the maximum load the unit is capable of carrying (if all possible steps are taken to increase the unit's capability) with valves wide open, 5 percent overpressure, normal temperature, and top feed water heater out of service.
   b. For combustion turbines, this is the peak reserve temperature control capability, which is the maximum rating at which the unit can be operated, generally for a limited period of time with increased maintenance costs.

c. For diesel units this is the same as the reserve rating.

When HELCO purchases Non-Utility Generation firm capacity, these sources may be represented as generating units with Normal Top Load, Reserve, and Emergency ratings determined to be at reasonable levels which are consistent with the intent of these definitions and consistent with the purchase power contracts.

New generation will be added to prevent the violation of the rule listed below where "available units" means all operable units and firm capacity suppliers physically connected to the system which are not on scheduled maintenance.

The sum of the reserve of all available units, with a unit on maintenance, less the reserve rating of the largest available unit must be equal to or greater than the system peak load to be supplied.

$$\sum_{i=1}^{N} B_i \geq \text{Load}$$

In addition, consideration will be given to maintaining a reserve margin of approximately 20 percent based on Reserve Ratings.

The application of this rule in long-range generation expansion studies must consider the effects of interruptible loads, Demand Side Management and the agreements for firm power and firm standby power.

The preceding rules apply to capacity planning in long-range generation expansion studies. The actual commercial operation date for the next unit to be added shall also be determined using these rules as guides, with due consideration given to short-term operating conditions, equipment procurement, construction, regulatory approvals, financial and other constraints, etc.

One HELCO unit will normally be running at all times.

Automatic load shedding is an operating reserve and is not to be considered as a resource reserve in generation planning studies.

At some future date it may be desirable to change the rules set forth above to provide additional reserves. This change will be dependent on actual operating conditions, financial restraints, and other constraints.

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	SUBJECT: Capacity Planning Criteria for Addition of Generation HELCO Long-Range Expansion Studies	DATE: December 4, 2003		
		CANCELS: January 22, 1997		

The rules below provide for additional reserves as compared to the rules above:

1. Spinning Reserve

   a. There must be enough generation running so that upon the tripout of any one unit the remaining units will have sufficient capacity to restore system frequency to 60 Hz.

   b. There must be enough generation running in economic dispatch so that upon the tripout of any one unit the remaining units will have sufficient quickload pickup capability to restore system frequency to at least 58.5 Hz within 3 seconds after tripout.

2. Loss of Load Probability

   Capacity planning analysis will include a calculation of risk (Loss of Load Probability) in years per day for each year of each plan of the long-range expansion study.

ENGINEERING STANDARD PRACTICE	SECTION: V SYSTEM PLANNING	SUBSEC B	PART 12.1	PAGE 1/5
	SUBJECT: Capacity Planning Criteria for Addition of Generation in MECO Long-Range Expansion Studies	DATE: March 29, 2000		
		CANCELS: April 3, 1998		

The following specifies how generating unit ratings, generation addition rules, and other considerations are used in determining generation addition requirement dates for the MECO systems.

GENERATING UNIT RATING DEFINITIONS

Generating units shall be given the following kilowatt ratings, where applicable, for use in determining generation addition requirement dates to the MECO systems. None of these ratings will exceed the generator nameplate maximum kva rating at rated power factor, under any condition.

1. Normal Top Load Rating: (A_1, A_2, A_3,..., A_N)

   a. For steam turbines this is the maximum load the unit is capable of carrying continuously on a normal day-to-day basis with valves wide open, normal pressure, normal temperature, and all feed water heaters in service. This is the maximum load to which the unit is normally dispatched.

   b. For combustion turbines this is the base temperature control capability, which is the maximum load the unit is capable of carrying continuously on a day-to-day basis.

   c. For diesel units this is the maximum continuous capability, which is determined by the manufacturers recommendations and operating conditions.

2. Reserve Rating: (B_1, B_2, B_3,..., B_N)

   a. For applicable steam turbines this is the maximum load the unit is capable of carrying continuously on a day-to-day basis with valves wide open, 5 percent overpressure, normal temperature, and all feed water heaters in service.

   b. For combustion turbines this is the base temperature control capability, which is the maximum load the unit is capable of carrying continuously on a day-to-day basis.

   c. For diesel units this is the two-hour, 10 percent overload capability.

3. Emergency Rating: (C_1, C_2, C_3,..., C_N)

   a. For applicable steam turbines this is the maximum load the unit is capable of carrying (if all possible steps are taken to increase the unit's capability) with valves wide open, 5 percent overpressure, normal temperature, and top feed water heater out of service.

b. For combustion turbines this is the peak reserve temperature control capability, which is the maximum rating at which the unit can be operated, generally for a limited period of time with increased maintenance costs.

c. For diesel units this is the same as the reserve rating.

When MECO purchases Non-Utility Generation firm capacity, these resources may be represented as generating units with Normal Top Load, Reserve, and Emergency ratings determined to be at reasonable levels, which are consistent with the intent of these definitions and consistent with the purchase power contracts.

GENERATION ADDITION RULES

The following generation addition rules apply to capacity planning in long-range generation expansion studies to determine the requirement dates for generation additions to the MECO systems. The latest approved sales and peak demand forecast will be used in the application of these rules.

For the Maui Division

New generation will be added to prevent the violation of the rules listed below where "units" mean all units and firm capacity suppliers physically connected to the system, and "available unit" means an operable unit not on scheduled maintenance. Loss of a step-up transformer utilized by more than one generating unit is not considered in planning generating unit additions to the Maui system.

1. The sum of the reserve ratings of all units minus the reserve rating of the largest available unit minus the reserve ratings of any units on maintenance must be equal to or greater than the system peak load to be supplied.

$$\sum_{i=1}^{N} B_i - B_L - B_M \geq \text{System Peak Load}$$

where N = total number of units on system

B_L = reserve rating of largest available unit

B_M = total of reserve ratings of units on maintenance

In addition, consideration will be given to maintaining a reserve margin of approximately 20 percent based on Reserve Ratings.

2. There must be enough generation running in economic dispatch to meet the expected system load. A minimum of two MECO units shall normally be running at all times.

   The application of this rule in long-range generation expansion studies must consider the effects of interruptible loads, Demand Side Management, and the agreements for firm power and firm standby power.

For the Lanai and Molokai Divisions

New generation will be added to prevent the violation of any one of the rules listed below where "units" mean all units and firm capacity suppliers physically connected to the system, and "available unit" means an operable unit not on scheduled maintenance. Loss of a step-up transformer utilized by more than one generating unit is not considered in planning generating unit additions to the Lanai and Molokai systems.

1. The sum of the normal top load ratings of all units must be equal to or greater than the system peak load to be supplied.

$$\sum_{i=1}^{N} A_i \geq \text{System Peak Load}$$

   where N = total number of units on system

2. With no unit on maintenance, the sum of the reserve ratings of all units minus the reserve rating of the largest available unit must be equal to or greater than the system peak load to be supplied.

$$\sum_{i=1}^{N} B_i - B_L \geq \text{System Peak Load}$$

   where N = total number of units on system

   B_L = reserve rating of largest available unit

3. With a unit on maintenance:

   a. The sum of the reserve ratings of all units minus the reserve rating of the largest available unit must be equal to or greater than the daytime peak load to be supplied.

   $$\sum_{i=1}^{N} B_i - B_M - B_L \geq \text{Daytime Peak Load}$$

   where N = total number of units on system

   B_M = reserve rating of unit on maintenance

   B_L = reserve rating of largest available unit

   b. The sum of the reserve ratings of all units must be equal to or greater than the evening peak load to be supplied.

   $$\sum_{i=1}^{N} B_i - B_M \geq \text{Evening Peak Load}$$

   where N = total number of units on system

   B_M = reserve rating of unit on maintenance

4. There must be enough generation running in economic dispatch to meet the expected system load. A minimum of two MECO units shall normally be running at all times.

   The application of this rule in long-range generation expansion studies must consider the effects of interruptible loads, Demand Side Management, and the agreements for firm power and firm standby power.

The preceding generation addition rules for both the Maui and Lanai and Molokai Divisions apply to capacity planning in long-range generation expansion studies. The actual commercial operation date for the next unit to be added to the MECO systems shall be determined using these generation addition rules as guides, with due consideration also given to the following: short-term operating conditions, mix of generation resources, minimum demand considerations, required power purchases, supplemental energy purchases, power purchase uncertainties, transmission considerations, system stability considerations, equipment procurement, unit construction, regulatory approvals, unit permitting, financial considerations and other constraints.

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		CANCELS: April 3, 1998		

LOAD SHEDDING

Automatic load shedding is an operating reserve and is not to be considered as a resource reserve in generation planning studies.

FUTURE CHANGES TO GENERATION ADDITION GUIDELINES

At some future date it may be desirable to change the rules set forth above to provide additional reserves. This change will be dependent on actual operating conditions, financial restraints, and other constraints.

The rules below provide for additional reserves as compared to the generation addition rules above:

1. Spinning Reserve

   a. There must be enough generation running so that upon the tripout of any one unit the remaining units will have sufficient capacity to restore system frequency to 60 Hz.

   b. There must be enough generation running in economic dispatch so that upon the tripout of any one unit the remaining units will have sufficient quick-load pickup capability to restore system frequency to at least 58.5 Hz within 3 seconds after tripout.

2. Loss of Load Probability

   Capacity planning analysis will include a calculation of risk (Loss of Load Probability) in years per day for each year of each plan of the long-range expansion study.

Approved: William A. Bonnet, President, Maui Electric Company, Ltd. — April 7, 2000 Date

Hawaiian Electric Company, Inc.
Avoided Cost Methodology

I. Defined

"Avoided costs" are the costs that the utility would avoid by purchasing capacity and energy from a qualifying facility. Avoided costs comprise two components: avoided capacity costs and avoided energy costs. Avoided capacity costs include avoided capital costs (e.g., return on investment, depreciation and income taxes) and avoided fixed operations and maintenance ("O&M") costs. The typical avoided capacity cost components include firm generating capital costs, generation capital working cash, transmission capital costs, transmission capacity losses, fixed O&M costs, fixed O&M working cash, land costs, and insurance costs.

Avoided energy costs include avoided fuel costs and avoided variable O&M costs. The typical avoided energy cost components include fuel costs, fuel working cash, fuel inventory, transmission energy losses, variable O&M costs, and variable O&M working cash.

If an electric utility is able to secure capacity and energy from a qualifying facility, the utility would be able to avoid incurring the capacity and energy costs associated with purchasing and running its own generating unit(s). It should be noted that energy costs may be avoided either by not running existing generating units or by not installing and running additional units. However, capacity costs can only be avoided by deferring the purchase and installation of an additional firm power resource.

The utility is only obligated to pay avoided cost to a qualifying facility. A qualifying facility ("QF") is a cogeneration facility or a small power production facility which is a QF under section 6-74-4 and Subpart B (per 18 CFR Part 292 Regulations under Sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 with Regard to Small Power Production and Cogeneration, as modified on February 24, 1995). The requirements include that the facility generate electricity using a technology which either sequentially produces electric energy and another form of useful energy (such as heat or steam) using the same fuel source (cogeneration) or uses renewable energy as a fuel source. In addition, certain ownership, operating, and efficiency criteria established by the Federal Energy Regulatory Commission must be met.

II. Description

HECO uses the differential revenue requirements method to calculate long-term avoided costs with respect to proposed firm-capacity purchase power agreements ("PPAs"). The differential revenue requirements method uses a "base" (typically least cost) utility plan, which is developed and modeled to determine capacity, fuel, and O&M costs. The base utility plan is compared to a QF proposal. An alternate plan is developed with the QF unit installed based on the QF developer's proposal and how HECO would dispatch all units on the system, including the QF unit. The difference in the utility's costs between the two plans represents the cost that HECO can avoid by implementing the QF alternative.

III. Plan Development

A. *Base Plan Development*

HECO's planning period is typically 20 years into the future as required by the PUC in its framework for Integrated Resource Planning ("IRP"), which generally provides sufficient data to determine the pros and cons of alternative plans. For long-term avoided cost calculations, the planning period is extended to include the end of the proposed PPA term.

The base plan development process generally includes the following:

- assessing existing resources;
- developing peak load, fuel price, and financial parameters forecasts, including construction of load models representing future customer demand;
- evaluating various resource options (e.g., demand-side management programs, alternate energy sources, proven generating unit technologies) that must be implemented or added to meet customer demand;
- determining the locations for the chosen generation resources;
- determining the substation and transmission facilities required to connect the generation resources into the existing utility electrical system;
- identifying resource, scheduling, and/or financial constraints;
- developing system simulations to evaluate reliability levels, O&M expenditures and potential problems in integrating planned additions with the existing system;
- performing scenario, sensitivity and risk analyses to determine plan flexibility and resilience in view of future uncertainties;
- conducting financial analyses to identify least-cost plans, as practicable that are also financable; and
- performing plan review and implementation.

HECO's most current IRP strategy and planning assumptions are used to develop the base plan, upon which avoided cost computations are based. During negotiations with QFs, HECO will calculate avoided costs using the latest available information, which may differ from the IRP or Electric Utility System Cost Data filings. Updated information would generally be obtained from the utility's annual IRP evaluations, from more recent filings with the PUC, or from periodic updates internally generated by the utility, such as the peak load and fuel forecasts. Changes in forecasts or assumptions will likely change elements of the base plan, including the timing and type of resource additions. In some instances, certain objectives or system benefits associated with a base plan may not be achieved by a QF (e.g., fuel diversity or system reliability). In those instances, the computed avoided cost must compensate for the benefit(s) not provided by the QF proposal. For example, if the QF proposal does not provide the system benefits of the base plan, the least cost economic plan (which may not necessarily be the base plan) could be assigned as the base plan for the purpose of computing avoided cost.

Illustrative Example of a Base Plan

Year	Unit Addition
2000	50 MW combined cycle unit
2001	
2002	60 MW combined cycle unit
2003	
2014	60 MW combined cycle unit

B. *Alternate Plan Development*

The differential revenue requirement method of computing avoided cost uses a "resource out" vs. "resource in" comparison. They are also referred to as the "QF-out" and "QF-in" plans. The QF unit is installed based on the QF developer's proposed schedule, or possibly HECO's evaluation of the proposed schedule. An analysis is performed using the capacity planning criteria to determine what unit additions after the QF installation can be deferred. Production simulations are performed for the base and alternate plan cases. In the alternate plan, the utility-owned units and existing power purchase units are dispatched with the proposed QF.

1. QF Price Proposal

The dispatch of the QF unit in the production simulation is dependent in part upon the QF developer's energy price proposal. The energy price proposal should ideally be in the form described in equation (1) below[6], together with a fuel cost in $/MBTU. The production simulation model used to compute avoided cost makes use of a second degree equation, which is a curve fit to the unit input-output data points, and a base fuel price to perform an equal incremental cost dispatch to minimize fuel costs.

Unit Input-Output Equation

The fuel requirements versus load for a unit are defined by the second degree equation shown below:

$$F = A + BL + CL^2 \qquad (1)$$

where: F is the fuel input in million of BTU (MBTU) per hour,

A, B, and C are equation constants determined by a least squares curve fitting process and are data inputs to the production simulation model.

L is the load on the unit in megawatts

The unit's incremental heat rate versus load is an equation generated internally by the production cost model from the above equation by differentiating it to produce an equation of the form:

$$I = \frac{dF}{dL} = B + 2CL \qquad (2)$$

Where I is the incremental heat rate in MBTU/MWH. Multiplying the equation by the fuel cost in $/MBTU gives the incremental cost rate in $/MWH.

The first order equation provides a smooth curve for dispatching units economically in 1 MW increments. The model dispatches the unit between minimum and

[6] The requirement in §6-74-15(d) is that a qualifying facility's offer must "contain specific prices and specific terms and conditions of all essential elements generally found in power purchase contracts ...".

maximum capacity using economic dispatch. Economic dispatch is the procedure by which the total system load is apportioned among a set of running units so as to produce the required energy at least cost. The minimum cost results when all units are running at the same incremental cost rate. If HECO were to use a different production simulation model to compute avoided energy costs, the data requirements of this model would generally drive the data requirements needed from the NUG developer.

2. QF Operation

   In addition to the fuel price, the maximum and minimum QF capacities, the proposed duty cycle (base load, cycling, or peaking), and the site location affect how HECO would operate the QF unit. HECO will accept base load operation to the extent possible, but cannot commit to base load operation for the term of a power purchase agreement. The system is constrained due to existing base load units that are not designed for cycling duty, existing power purchase contracts with base load and minimum take provisions, and a low system minimum load during the off-peak hours. For HECO the term base load is used to designate units that operate 24 hours per day. But unlike the standard EEI definition, a base load unit does not operate at a near constant output. Rather, due to the characteristics of the island's daily load profile, base load units must dispatch daily between their maximum and minimum capacity ratings. Because cycling capability is required on the system, new units, including QFs, are required to be able to cycle off-line on a daily basis. Startup priority is determined based on absolute fuel costs and the location of existing and future units compared with the energy price and location for the QF unit.

3. QF Location

   The site for the QF unit determines transmission interconnection requirements as well as the need of the unit for area reliability and voltage support.

   The site for the QF unit also impacts transmission system losses. Transmission losses comprise two components. One is the capacity (KW loss) component and the other is the energy (KWH loss) component. These transmission loss components are the capacity and energy that is lost when electricity is transmitted from the generating site to the utility's distribution system. Adding generation closer to the load center (relative to HECO's location for its next generating unit) will generally decrease system losses, while adding generation further away will generally increase system losses.

C. Base and QF-in Plan Comparison

A comparison is made of the HECO fuel and O&M costs associated with the base and alternate plan (and, of the deferral of any units caused by the QF). The costs for the QF unit in the alternate QF-in plan are assigned a zero-cost to the utility. Conceptually, the difference between the costs of the base and alternate plan represents the cost the utility would be able to *avoid* because of the QF. This difference in cost represents the avoided cost.

In the following illustration, the QF proposal is assumed to be a 25 MW biomass unit with a contract term of 15 years.

Illustrative Example of a Base and Alternate Plan

	Base Plan		Alternate Plan
2000	50 MW combined cycle unit	2000	**QF** - 25 MW biomass unit
2001		2001	
2002	60 MW combined cycle unit	2002	50 MW combined cycle unit
2003		2003	60 MW combined cycle unit
2014	60 MW combined cycle unit	2014	**QF** Contract Terminates
2015		2015	60 MW combined cycle unit

The QF unit, in this example, deferred the need for the 50 MW combined cycle unit by two years, and the 60 MW combined cycle unit by one year. However, a second 60 MW combined cycle unit is needed in the base plan by 2014. The QF unit is a different size than what HECO would have installed and introduces differences in the timing of the unit additions between the base and the alternate plan. Similarly, because there are different sizes of units in the base plan, introduction of the QF unit would cause differences in timing, even if it were the same size as the 50 MW unit in the base plan. This results in an unequal treatment of costs in the base and alternate plans. HECO captures these cost differences by performing an end effects calculation which is described in the following section.

At the end of the contract term the QF unit must be replaced by whatever utility capacity would be added next in the base plan. The planning period must be extended a year or two to capture this replacement capacity. In the above example, when the QF contract terminates at the end of 2014, a 60 MW unit is added in the alternate plan in 2015, at which point the base and alternate plan capacities are equal.

IV. Economic Analysis

A. Revenue Requirement Development

After development of the base and alternate plans, all costs that are different between the base and alternate plan are identified through the use of a production simulation computer model. These may include capital expenditures, fuel, O&M and other expenses. Capital-related costs include depreciation and return on rate base. Return on rate base is the utility's cost of financing a capital investment (including income taxes). Utility planners determine avoided fuel, O&M and other avoided costs. Revenue taxes are excluded from the avoided cost calculation because the ratepayers pay revenue taxes on all revenues that the utility collects, including those

revenues that will be used to pay the QF. As a result, revenue taxes are not avoided and are therefore not included in the avoided cost calculation. Calculations are made in accordance with PUC Docket 7310.

HECO uses a present value factor in its avoided cost calculations. This present value factor is the present value of the capital-related costs of a $1 investment over the life of the generating unit (capital-related costs are developed for each generating unit and transmission equipment to be built). This factor is the present value of the annual capital-related costs. HECO uses the after-tax weighted cost of capital as its discount rate.

When developing revenue requirements for the alternate plan, the QF unit is assigned a zero-cost to the utility.

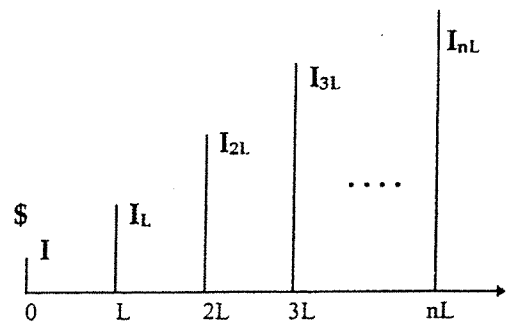
B. *End Effects*

When the QF-in (alternate) plan with the QF unit is developed, a timing difference for unit addition costs beyond the planning period can occur with the alternate plan when compared to the base plan. To account for the timing difference an end effects calculation is performed.

HECO uses a "like-kind replacement to perpetuity method" to calculate end effects. Essentially, once the base plan and the alternate plan reflect equivalent capacities, each generating unit (in each plan) is assumed to be replaced with like-kind units, to infinity. A similar calculation is performed for transmission equipment. The formula used to calculate end effects is sometimes referred to as the "economic carrying charge" formula. A derivation of the formula is provided below[7].

Assume than an investment I with an expected life of L years is made at time $t = 0$. A representation of the investment stream over time (assuming infinite replacement) is shown below:

7 See also J.L. Seelke, Jr., "Assessing the Benefits of Load Control", Appendix, IEEE Trans. Power App. Syst., Vol. PAS-101, pp. 3892-1901, Oct. 1982 ("A derivation of Mathematical Expressions for Calculating Avoided Revenue Requirements")



$$I_{nL} = I(1+i)^{nL}$$
$$I_{nL} = I + I(1+i)^{L} + I(1+i)^{2L} + \cdots$$
$$PVRR = KI + KI\left(\frac{1+i}{1+dr}\right)^{L} + KI\left(\frac{1+i}{1+dr}\right)^{2L} + \cdots$$

where,

I	=	investment at $t = 0$
I_{nL}	=	investment required to replace I after nL years
i	=	inflation rate
dr	=	discount rate
K	=	present value of $1 investment over L years
$PVRR$	=	present value of revenue requirements

The last equation can be expressed as:

$$PVRR = KI \times \sum_{n=0}^{\infty}\left(\frac{1+I}{1+dr}\right)^{nL}$$

This equation is a geometric progression that converges to the following, provided that the discount rate is larger than the inflation rate:

$$PVRR_{\infty} = KI \times \left[\frac{1}{1-\left(\frac{1+i}{1+dr}\right)^{L}}\right]$$

The present value of revenue requirements is calculated from a "base year," which is generally the year the QF becomes operational. In the illustrative example, that year would be 2000.

The PVRR is calculated for each unit in each of the two plans. For units being installed *after* the base year, investment escalation needs to be accounted for as well as the appropriate discounting for present value purposes.

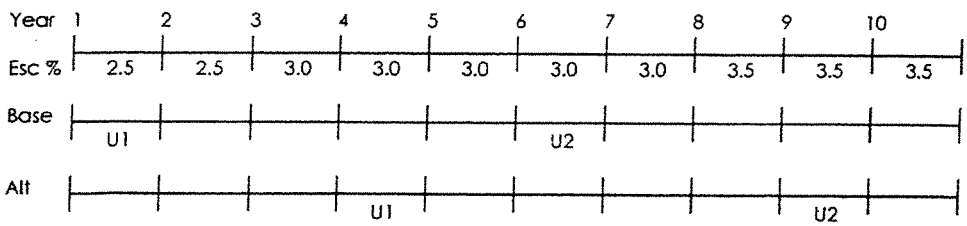
The PVRR for each plan (in base year dollars) is just the sum of the PVRR components:

$$PVRR_{\text{Base}} = PVRR_{\infty,1} + PVRR_{\infty,2} + PVRR_{\infty,3} + \cdots$$

$$PVRR_{\text{Alternate}} = PVRR_{\infty,1} + PVRR_{\infty,2} + PVRR_{\infty,3} + \cdots$$

However, annual escalation rates for the planning period need to be accounted for in the infinity calculation where the escalation used to infinity is different. A unit which is installed prior to constant escalation is divided into two costs: (1) the cost at the install date which is not taken to infinity, and (2) the cost escalated to the replacement year which is taken to infinity. This method of calculating capital cost is applied to units in both the base and alternate case which are in this category.

In the following example, escalation rates vary from year 1 through year 8. Beginning in year 9 the escalation is forecasted to remain at 3.5 % for the infinity calculation.



In the base case, Unit 1 ("U1") and Unit 2 ("U2") are installed prior to constant escalation. U1's cost is escalated to the installation date and present valued to the base year. U1 is assumed to be replaced in kind at the end of one life cycle. U1's replacement unit cost is calculated using the derived formula where I is the U1 cost escalated to the replacement year. The sum of these two costs represents U1's cost to infinity. U2 is calculated similarly.

In the alternate case, only U1 is installed prior to constant escalation. U1 follows the method used for U1 in the base case. Since the escalation is constant after the U2 installation, the cost is calculated using the derived formula where I is U2's install year cost.

V. Avoided Capacity Cost Calculations

Avoided capacity cost components include generation capital, generation capital working cash, transmission capital, transmission capacity losses, fixed O&M, fixed O&M working cash, land and insurance. As described in the previous section, end effects account for differences in the timing of resource additions. The remaining components of avoided capacity costs are calculated on an annual basis up to the end of the PPA contract term.

Avoided capacity costs are normally summarized in present value dollars and levelized dollars in $/KW-YR. HECO's policy is not to commence capacity payments until the generating capacity need date, as determined by HECO based on the latest available information, is reached. Actual commencement of capacity payments will be negotiated in a case by case basis.

VI. Avoided Energy Cost Calculations

Avoided energy cost components include fuel, variable O&M, variable O&M working cash, fuel working cash, fuel inventory, and transmission energy losses. Avoided energy costs are normally summarized as present value dollars and unescalated base energy rates in $/KWH. Fuel is normally escalated at a different rate than O&M, so that the two base rates in $/KWH cannot be totaled.

VII. QF Price Calculations

In order to compare the QF's pricing proposal to avoided cost, the QF pricing proposal is calculated over the contract term and is expressed in present value dollars. The QF's capacity pricing proposal is present valued using the utility's discount rate.

The QF energy pricing proposal generally includes fuel and variable O&M prices. Variable O&M proposals may be further broken down into an energy (MWH) price and an operating hour price. As explained in section III.B, the QF unit is dispatched in the production simulation using the proposed energy fuel price. This determines the amount of energy displaced (avoided) in the QF-in plan. The fuel component of the energy price is normally taken directly from the production simulation output. The O&M component of the energy price to the QF is calculated based on the QF's proposal. Variable O&M pricing proposals may use the energy (MWH) generated by the QF multiplied by the appropriate energy ($/MWH) charge and the hours operated multiplied by the operating hour ($/Hr) charge. The total energy costs using the QF's energy pricing proposals are present valued at the utility's discount rate.

VIII. Avoided Cost Results

The primary objective of the avoided cost calculation is to determine whether the energy and capacity payment rates included in the QF's proposal are at or below HECO's avoided cost. The QF's proposal could have capacity and energy rates that differ from the avoided cost without exceeding the total avoided cost.

In order to evaluate the QF price proposal to HECO's avoided cost, the total present value of the QF pricing proposal (total capacity cost plus total energy cost) must be compared to the total present value of avoided cost (total avoided capacity cost plus total avoided energy cost). If the QF's proposal is below avoided cost, the energy fuel payment would be made based on the proposal, since this was used in the production model dispatch to determine the energy avoided cost.

If the QF's proposal is above avoided cost and the developer wishes to, the developer could revise their proposal to be at or below avoided cost. This entitles the developer to a power purchase agreement with HECO, provided that the parties can agree to all of the other terms and conditions in the power purchase agreement.

APPENDIX C

Derivation of the Most Efficient Operating Point for Individual Generating Units

Derivation of the Most Efficient Operating Point for Individual Generating Units

The efficiency characteristics of a generating unit are modeled as a second-degree equation referred to as the heat rate equation:

$$E = \left(\frac{A}{L} + B + CL\right) \qquad (1)$$

where:

A is in units of MBTU/HR
B is in units of MBTU/MWHR
C is in units of MBTU/MW^2-HR, and
L = load in MW

The most efficient loading point is derived by taking the first derivative of the heat rate equation with respect to the load, setting the equation to zero, and solving for L:

$$\frac{d}{dL}\left(\frac{A}{L} + B + CL\right) = 0$$

$$-\frac{A}{L^2} + C = 0$$

$$CL^2 = A$$

$$L = \sqrt{\frac{A}{C}} \qquad (2)$$

To verify that the minimum heat rate occurs at the load level, L, the second derivative of the heat rate equation is taken with respect to load. The minimum heat rate occurs when the second derivative is greater than zero.

$$\frac{d^2E}{dL^2} = \frac{2A}{L^3} \qquad (3)$$

Substituting equation 2 into equation 3.

$$\frac{d^2E}{dL^2} = 2\sqrt{\frac{C^3}{A}} \qquad (4)$$

With the A and C constants expressed as positive values, the second derivative will always be greater than zero. Therefore, the load level, L, calculated by equation 2

represents the most efficient loading point. However, if L is greater than the normal top load ("NTL") of the generating unit, the most efficient loading point of the unit is at NTL.