Appendix A

Avoided Cost

Compiled by HECO based on information provided by collaborative parties

APPENDIX A

Avoided Cost

As-available energy prices are treated differently than firm capacity prices.

As-available avoided energy costs are filed with the PUC on a quarterly basis pursuant to H.A.R. §6-74-17(b). The filed on-peak and off-peak as-available energy costs are determined by the proxy method established by the PUC in 1985 in Docket No. 4569. The filed avoided energy cost rate includes an avoided fuel cost component and an avoided variable O&M component.

For a number of years, qualifying facilities ("QFs") and nonfossil fuel producers subject to the PUC's avoided cost rules have maintained that the filed avoided energy cost rates understate the utilities' actual avoided energy costs, while the electric utilities have maintained that the filed rates overstate their avoided energy costs. The PUC examined this issue in a generic proceeding, Docket No. 7310. Most of the issues in the proceeding were resolved, subject to PUC approval, by a Stipulation To Resolve Proceeding filed on March 4, 1994. Under the Stipulation, the parties agreed that (1) the proxy method should be discontinued, (2) avoided fuel costs should be determined based on a computer production simulation model, except for Lanai and Molokai (for which the service areas are too small), (3) avoided generation O&M costs should include consumables, working cash and fuel inventory, (4) an allowance should be made for transformer losses for QFs that utilize synchronous (but not induction) generators and are metered on the "high-side" of the step-up transformer, and (5) transmission line losses should be determined on a case-by-case basis. The PUC has not yet approved the Stipulation. However, once the new calculation procedure is implemented, the avoided energy costs may be lower for HECO and MECO, and about the same for HELCO, even though additional elements will be included in the avoided energy cost calculation. The precise avoided energy costs will not be known until the calculation procedure is implemented.

The parties did not reach agreement as to whether the electric utilities would avoid any capacity costs as a result of the purchase of energy on an as-available basis, or as to whether an environmental externalities adder should be included in determining avoided energy costs (see barrier 1.e.). These issues were submitted to the PUC for consideration.

Capacity Adder for As-Available Resources

Certain jurisdictions that have diversified, as-available energy resources (and which utilize a capacity planning criteria based on loss of load probability or unserved energy), such as California, have recognized an avoided capacity value for as-available energy resources.

Much of the work relating to the capacity credit or capacity value of wind power has used numerical methods based on empirical load and wind speed duration curves (or probability distributions). Other work employed analytical models allowing a qualitative investigation of the variation of capacity credit with a wide range of grid, aerogenerator, and load parameters. The simplest measure of capacity credit is the Equivalent Firm Capacity.

The impact of wind plants on system reliability is very system-specific, however, depending to a large degree on the size of the utility's reserve margin. The size of the resources in the system will also affect the capacity value. Thus, the capacity value of a wind plant will be system-specific as well as resource-specific. Wind plant capacity values cannot reliably be generalized across utilities and resources. As a result, there is, as yet, no consensus on the proper framework for assessing just what the system reliability impact - or "capacity value" of a wind plant is.

The NUG parties in Docket No. 7310 proposed that capacity credits be provided to as-available energy producers based on the equivalent load carrying capability of their generating units. They maintained that a first order approximation would be the plant's on-peak capacity factor multiplied by the nameplate capacity of the plant, and recommended that the PUC set a rebuttable presumption that the capacity value for as-available energy would be equal to 100% of the annual cost of a combustion turbine per on-peak kwh, for kwh actually delivered on-peak, until the utilities perform an equivalent load carrying capability analysis.

The CA in Docket No. 7310 proposed that as-available producers be allowed a much smaller payment based on the reliability benefits provided by as-available resources. The proposed "premium" would be based on the on-peak capacity factor of the producer in the prior year times 50% of the annual fixed capital and O&M costs of a peaking resource of equal nameplate capacity. The CA also proposed two conditions to be met by as-available producers to qualify for the premium: (1) the developer should commit the output of their resources to the utility for a minimum of five years -- although the as-available producer would still be under no obligation to deliver energy to the utility if there is no output in any given period, and (2) the developer should be required to take reasonable steps to coordinate the maintenance of the resource.

The HECO Utilities and KE maintain that they do not avoid capacity additions as a result of as-available energy purchases. In Docket No. 7310, the HECO Utilities based their position on their capacity planning criteria, the definition of firm capacity in the PUC's Avoided Cost Rules (which includes scheduled amounts of capacity which a QF has a legally enforceable obligation to make available under utility dispatch), and the terms and conditions of existing as-available energy contracts (under which as-available energy suppliers have no obligation to deliver power and energy when it is needed by the companies and no continuing obligation to maintain production levels).[1] In their view, as-available energy purchases can provide additional reliability value, but this form of "capacity" value is speculative. In order to consider the "equivalent load carrying capability" of such resources, they maintained that it would be necessary to consider (1) the degree to which a specified quantity of as-available energy would be guaranteed for any year, (2) appropriate penalties for non-performance, (3) the term of the commitment to provide as-available energy, and (4) the load and capacity situation of the utility, and the ability of the utility to defer new supply-side resources.

The Department of Defense also took the position that utilities do not avoid any capacity costs when energy is purchased on an as-available basis.

Firm Capacity

Capacity payments have only been made for firm capacity, which is defined as scheduled capacity made available under utility dispatch. H.A.R. §6-74-1 ("Firm capacity).

1 In their view, a small utility without interconnections cannot afford to design its generating system (i.e., to select between baseload and peaking units) on the basis of minimal commitments on the part of as-available energy producers.

The HECO Utilities use the differential revenue requirements ("DRR") methodology to calculate long-term avoided costs with respect to proposed firm capacity PPAs.[2] The DRR methodology uses a base (least cost) utility plan to determine the capacity, fuel and O&M cost. The base utility plan is compared to a Non-Utility Generator ("NUG") proposal. An alternate plan is developed with the NUG unit installed based on the developer's proposal. The difference in the utility's costs for the base utility plan and the alternate plan represents the costs that HELCO can avoid by implementing the NUG alternative. The DRR methodology utilizes a capacity planning model,[3] a production simulation model,[4] and a revenue requirements model.

The calculation of avoided capacity costs for firm capacity PPAs has been more of an issue with qualifying cogeneration facilities, than with renewable energy producers. The PUC has approved avoided capacity costs derived using the DRR methodology in a number of dockets in which firm capacity PPAs were approved by the PUC. In addition, there are two recent proceedings in which the PUC has resolved or is expected to resolve other issues regarding the calculation of avoided cost for firm capacity PPAs. These include Docket Nos. 7956 (Kawaihae Cogeneration Partners) and 94-0079 (Enserch Development Corporation). See Re Hawaii Electric Light Co., Docket No. 7956, Decision and Order No. 14030 (July 31, 1995).

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2 The DRR, or "planning methodology", is one of three generally accepted methodologies to determine avoided costs. The other two avoided cost methodologies are the peaker method and the proxy plant method. The peaker method is a marginal cost approach. It is referred to by several names including the component method and short-run marginal cost. In applying the method, avoided capacity costs are set equal to the cost of a new peaking unit (or lower if there is surplus capacity) and avoided energy costs are determined as system marginal energy costs. The proxy plant method identifies the next unit that would be added by the utility. Both capacity and energy costs are set based upon the cost of the proxy unit.

3 The capacity planning model uses the utility's capacity planning criteria to determine unit additions in the base and alternate plans to model the impact of the NUG unit on the utility's unit addition plans.

4 The production simulation model captures the impacts of the NUG unit on the utility's system energy and O&M costs.

Avoided transmission and distribution ("T&D") losses

Electric power systems that generate, transmit and distribute electricity are not 100% efficient. The potential for more energy loss exists with each additional unit of electricity demanded at any given moment or over a period of time. The farther away from the generating source the demand for electricity is, the greater these losses become as a percentage of that demand. Thus, the total input into an electrical system must be larger than the sum of the system's customer demands. Conversely, the avoidance of load at the point of consumption also avoids the upstream losses that would have occurred had that power required transmittal to the customer.

Electrical systems experience losses due to inherent resistance in the transmission and distribution lines, generator and transformer windings, and the magnetic circuits of the electrical equipment involved. Most of these losses vary in proportion to the square of the load. Losses associated with magnetic circuits are fixed losses. These are equipment dependent.

Losses occur within each stage of power transmittal on the electric system; transmission, sub-transmission, primary distribution, and secondary distribution. These losses affect the calculation of a system's avoided costs because they imply necessary increases in the gross power capacity and energy generation to serve the utility's net consumer load at the point of consumption. Avoided net load at the meter avoids the additional fraction of capacity and energy that would have been necessary to supply (for losses) had the avoided customer load been served across the system.

Decentralized generators could improve the overall efficiency of a system because less energy would be lost in transmitting electricity across long distances.

The PUC's Avoided Cost Rules provide that avoided energy costs included "line loss costs when presented in a specific proposal from a qualifying facility to the electric utility." H.A.R. § 6-74-1 (definitions). The addition of renewable resources to the utility system can result in decreases or increases in the utility's system-wide losses, depending on factors such as the location of the RE projects relative to the utility's loads.