TESTIMONY OF

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Subject: Impact of DG on the Reliability of the T&D System, Conceptual Overview of T&D Avoided Cost Calculation, and the Impact of DG on the Power Quality of the T&D System & DG Interconnections

INTRODUCTION

Q. Please state your name and business address.

A. My name is Shari Ishikawa and my business address is 820 Ward Avenue, Honolulu, Hawaii.

Q. What is your present position with Hawaiian Electric Company, Inc. ("HECO")?

A. I am the Principal Transmission Planning Engineer in the Transmission Planning Division in the Power Supply Planning and Engineering Department. My educational background and experience are given in HECO-400.

Q. What will your testimony cover?

A. My testimony will cover:

1) Impact of Distributed Generation ("DG") on the reliability of the Transmission and Distribution ("T&D") system (Issue No. 5),
2) conceptual overview of T&D avoided cost calculation (Issue No. 6), and
3) the impact of DG on the power quality of the T&D system (Issue No. 5) and DG interconnection (Issue No. 9).

IMPACT OF DISTRIBUTED GENERATION ON THE RELIABILITY OF THE TRANSMISSION AND DISTRIBUTION SYSTEM

Q. Briefly explain the various DG Applications.

A. As explained in Mr. Seu's testimony, HECO T-1, HECO, Hawaii Electric Light company, Inc. ("HELCO") and Maui Electric Company, Limited ("MECO") have identified seven different applications of DG, including 1) Customer-sited emergency generation, 2) Substation-sited peaking generation, 3) Substation-sited generation to address case-specific T&D problems, 4) Customer-sited combined heat and power ("CHP"), 5) Customer-sited cogeneration, 6) Off-grid, customer-sited generation and 7) Customer-sited generation operated in parallel with the utility grid.

Q. How does each DG application impact the T&D systems of HECO, HELCO and MECO (which I refer to as the "Company")?

A. Each of the seven types of DG applications listed above will impact the T&D system differently. For instance, customer-sited generation operated in parallel with the utility grid and interconnected according to Rule 14H, and off-grid, customer-sited generation, which does not use the utility grid, will have different impacts on the T&D system.

Q. What impacts can DG have on the reliability of the Company's T&D systems?

A. Depending on where it is installed, DG can affect the reliability of a single customer's electric service or have an affect on the T&D system. The initial installations of small-scale DG units at customers' sites (for other than emergency backup) were often problematic for both the customer and the utility. From the customers' standpoint, there were performance problems with the units, with the fuel for the units and with the maintenances of the units. A number of initial units are no longer operable and/or have been replaced such as the HESS installed units at the University of Nations and at the Hualalei Regency. From the T&D system standpoint, unexpected outages that could be caused by poor unit performance or maintenance practices can adversely impact local voltage and frequency control.

Q. Can the installation of DG facilities benefit the reliability of electric service?

A. Yes, DG can benefit the reliability of a single customer's electric service or improve the reliability of localized areas of the T&D system. For instance, in the event of a utility interruption, a DG system, such as a CHP facility installed at a customer facility, may increase reliability for that customer. For this to happen, the DG system must be able to operate while connected to the utility power system and must also install interconnection equipment to the customer's electrical system to operate isolated from the utility. Installing back-up emergency diesel generators, capable of supporting critical portions of operations at customer sites, may also provide reliability improvement to a single customer's electric service. Installing DG at targeted utility substation can improve the reliability of a localized area of the T&D system and can also provide the ability to address generation and T&D concerns due to load growth. Generation and T&D planning processes are in place to identify load growth issues and reliability concerns. DG can be incorporated into the generation planning process, which is addressed in the testimony of Mr. Sakuda, HECO T-3. My testimony will address how DG can be used in the T&D planning process.

The Company's Transmission, Sub-transmission and Distribution Systems

Q. Describe how power is transported to customers on the HECO system.

A. The transmission system is the bulk power transfer system used to transmit large amounts of power over relatively long transmission lines from the source of generation to load centers. Currently the highest voltage used by HECO to transport power is the 138 kV transmission system. The transmission system allows efficient transmission of large amounts of power from the power plants, where power is generated, to all major load centers. Transmission substations at these major load centers have transformers that "step down" the voltage from 138 kV to the 46 kV sub-transmission level. From there, local area substations further reduce the voltage from 46 kV to HECO's 25 kV, 12 kV and 4 kV local distribution voltages.

Q. Describe how power is transported to the customers on the HELCO system.

A. Currently the highest voltage used by HELCO to transport power is the 69 kV transmission system. Distribution substations are connected at different locations along the transmission lines at major load centers and the transformers then "step down" the voltage from 69 kV to HELCO's 12 kV, 4 kV and 2.4 kV local distribution voltages. In some areas, HELCO has radial sub-transmission lines operating at a voltage level of 34.5 kV.

Q. Describe how power is transported to customers on the MECO system (island of Maui).

A. Currently the highest voltage used by MECO to transport power is the 69 kV transmission system. Transmission substations at these major load centers have transformers that "step down" the voltage from 69 kV to MECO's 12 kV and 4 kV local distribution voltages. MECO has a 23 kV sub-transmission loop interconnecting loads in the Kahului area and power generated from the Kahului Power Plant. Additional power from the Maalaea Power Plant are also transformed from the 69 kV transmission system to serve loads connected to the 23 kV sub-transmission system, as in the case of the Hana 23 kV line and the 23 kV line that serves the summit of Haleakala.

<u>The Company's T&D Planning Criteria</u>

Q. What is the purpose of the Company's Transmission Planning Criteria and Distribution Planning Criteria?

A. The purpose of the transmission and distribution planning criteria is to establish guidelines for planning a reliable transmission and distribution system for HECO, HELCO and MECO

Q. What are the Company's T&D Planning Criteria?

A. Transmission Planning Criteria for HECO, HELCO and MECO are shown in

HECO-401, HECO-402, and HECO-403 respectively. Distribution Planning Criteria for HECO, HELCO and MECO are shown in HECO-404, HECO-405 and HECO-406 respectively.

T&D Planning Process

Q. Please outline the Company's T&D planning processes.

A. The Company's T&D planning processes were presented at the April 23, 2004 IRP Advisory Group Technical Committee meeting. The attached outline of the transmission planning process and the distribution planning process for the Company's is shown in HECO-407 and HECO-408, respectively.

Q. What voltage levels does the transmission planning process include?

A. The transmission planning process is applied to 1) the HECO 138 kV, 2) the HELCO 69 kV and 34.5 kV sub-transmission system and 3) the MECO 69 kV and 23 kV sub-transmission system. The distribution planning process is applied on the 12 kV voltage level and below for HECO, HELCO and MECO. HECO's 25 kV distribution system and the 46 kV sub-transmission system are also included in the distribution planning process.

Q. What tools are used for planning the transmission system?

A. Computer models of the electric grid are utilized to represent a base case load flow. An electrical grid can be represented by a set of simultaneous linear algebraic equation expressing Kirchoff's laws for the utility system and the voltage, current and power characteristics of the loads. HECO uses a program called Power System Simulator for Engineering or PSS/E, which is developed by a company called Power Technologies, Inc ("PTI"). The PSS/E program is widely used by utilities and transmission planners in North America and around the world. The program conducts an iterative procedure to solve the algebraic equations for given loads and generator power outputs, which is referred to as the load flow or power flow calculation. The load flow simulation results can produce current flows and voltages on the utility electrical grid. The base case load flow uses historical load data and transmission planning will typically benchmark a peak load flow against historical data to ensure the accuracy of the models.

Q. How are the benchmarked models used for transmission planning?

A. The load distributions in the base case load flow are scaled by the load growth rate from the latest utility load forecast. Both long-term analyses covering 6-20 years and short-term analyses covering a period of 5 years or less are performed when needed. The load flow simulations are forward looking simulations and are used to determine voltages at substation busses and the amount of current flowing through various system configurations. Transmission Planning Criteria violations and reliability concerns are identified.

Q. Please explain the differences between criteria violations and reliability concerns.

A. Transmission Planning Criteria provide minimum guidelines for planning the transmission system, for instance, voltages exceeding acceptable tolerance levels or current flows exceeding the current carrying capacity of transmission lines are criteria violations. Criteria violations can be triggered due to load growth such as the Koolau/Pukele line overload described in the East Oahu Transmission Project ("EOTP"), Docket No. 03-0417, HECO T-4, page 7. Reliability concerns are identified by analyzing the reliability of customer's electric service and may exist even if there are no criteria violations. An example of a reliability concern is the reliability of the Pukele and Downtown area substations on the HECO system as described in EOTP, Docket No. 03-0417, HECO T-4, pages 33-48.

Q. What tools are used for the distribution planning process?

A. Most of the analysis in distribution planning is conducted looking at historical loads by taking actual load demand readings from distribution substation transformers and readings from each individual distribution line. In some cases, the PSS/E model is used to model select areas of the distribution system.

Q. Is a long-term forecast created for the distribution planning process?

A. No, because 1) distribution load forecasting is geographically dependent and therefore very dynamic, 2) growth rates between lines are highly variable, 3) distribution load forecasting is highly dependent upon customer plans (ex. – a new hotel can double the load on a distribution line) and 4) useful forecasting for distribution system rarely exceeds five years. This was explained at the April 23, 2004 IRP Technical Committee Distribution Planning Presentation.

Q. How are short-term forecasts used in the distribution planning process?

A. Short-term forecasts are used to determine power and current flows through the sub-transmission and distribution systems, voltages on the system, and transformer loadings. Distribution planning criteria and reliability concerns are identified.

Q. What options are considered and evaluated to resolve T&D planning criteria violations and reliability concerns?

A. Two types of options can be evaluated for the T&D systems: 1) the installation or modification of T&D facilities, and 2) load reduction options. These changes are evaluated to ensure that the proposed options address the identified criteria violation or reliability concern.

Q. What types of T&D facilities are considered?

A. In general, the following types of T&D options are considered including:

(1) increasing the capacity of the T&D system through the addition of new lines, reconductoring existing lines, re-tensioning existing lines (as discussed in EOTP, Docket No. 03-0417, HECO T-4, pages 76-78), or re-rating existing lines (through techniques such as dynamic line rating as discussed in EOTP, Docket No. 03-0417, HECO T-4, pages 75-76), (2) reconfiguring distribution or sub-transmission lines, which shift loads and change the current flows on the transmission system or provide redundancy on the distribution system (as discussed in EOTP, Docket No. 03-0417, pages 59-62), (3) adding var sources such as capacitors on the transmission system (refer to Docket No. 03-0388, Kailua Capacitors) and/or (4) adding additional transformer capacity on the sub-transmission and/or distribution transformers.

Q. Does the Company consider options other than installing or modifying T&D facilities considered?

A. Yes, non-T&D options such as implementing sustained demand side management ("DSM") programs and installing DG facilities have been considered in past T&D analyses and increased evaluation of non-T&D alternatives is being included in more recent T&D analyses. Non-T&D options related to DG facilities have included the evaluation of diesel generators at the Company's substations, customer-sited, utility-owned CHP programs and utilizing emergency standby generation.

Q. Explain how the DG facilities can address criteria violations and reliability concerns.

A. DG facilities can reduce the load served by the T&D system either on a continuous basis or during contingency situations. Reducing the load served by the T&D system will reduce current flow and could defer the need to install transmission facilities to address the criteria violations. The installation of a customer-sited CHP system, which is used continuously is an example of where the load reduction may be considered on a continuous basis (although maintenance of the unit(s) needs to be considered when planning for the system). Installing DG at substations, which are permitted to operate under emergency conditions is an example of DG used during contingency situations. The ability to operate under emergency conditions requires a contingency situation to occur before the DG unit can be utilized and the run hour times for these emergency units are restricted.

Diesel Generation at T&D Substations

Q. Have the Company's planning studies considered the installation of diesel generators at T&D substations?

A. Yes, the installation of diesel generators were considered for Hana Substation on the MECO system.

Q. What was the concern at the Hana Substation?

A. The Hana Substation is connected to the utility grid through a single radial transmission line. Prior to the installation of distributed generators, the area was at risk of power interruptions whenever there was a problem or maintenance needed to be done on the line. The installation of diesel generators provided an attractive alternative to installing additional transmission facilities and two diesel engine generators from the Lanai City Power Plant were relocated to Hana Substation No. 41 in order to provide standby electric service to the Hana community during planned service outages resulting from the maintenance or unplanned power outages of the single transmission line to Hana.

Q. What factors were considered?

A. The age of the single transmission line, the terrain surrounding the transmission line, the effect of an outage on the customer, and the cost for resolving the reliability issue were considered. The single transmission line is over 35 years old and has shown to be a weakness in the Hana area system reliability, repair and maintenance of the transmission line is often difficult because many sections of the line are in rugged terrain that is difficult to access, and in 1998, there were 11 unscheduled and scheduled outages affecting the Hana Substation, which resulted in service interruptions to Hana customers of almost 63 hours. Other considered options included installing a 35-mile redundant single circuit on steel poles from Kanaha substation was estimated to cost over $20 million or relocating two existing Lanai City Power Plant diesel engine generators to Hana. The actual cost to relocate the two generators to Hana was $1.24 million. It should be noted that relocation of the two existing Lanai City Power Plant diesel engine generators to Hana provided a relatively low cost option because the diesel engine generators were scheduled to be retired anyway and other issues such as the fuel supply and locating a suitable area in the substation were addressed.

Q. Was the installation of diesel generators at substations considered for other T&D concerns?

A. Yes, however there are practical considerations that limit the ability of diesel generators used on a targeted basis to defer specific T&D projects. DG was considered in the EOTP, Docket No. 03-0417 and is being considered in the 7200/7300 HELCO Line Overload Study. Installation of diesel generation in North Kohala was also considered as part of HELCO's March 1996 Contingency Plan Update, Docket No. 96-0029.

Q. Briefly describe how diesel generation at substations was considered in the EOTP, Docket No. 03-0417?

A. Planning analysis in support of Docket No. 03-0417 analyzed the effectiveness of diesel generation at HECO substations and another area of DG facilities, which included customer-sited utility-owned CHP programs to resolve substation reliability concerns and line overload situations. Diesel generation at substations and utility-owned CHP programs can be analyzed to measure their effectiveness to address criteria violations such as line overload situations and reliability concerns. My testimony in Docket No. 03-0417, HECO T-4, pages 66-71, discusses the March 2000 DG Alternatives Study, which evaluated the ability for DG to address reliability concerns on the HECO system. The March 2000 DG Alternatives Study focused on the practical issues of installing DG units as an option to address both line overload and the Pukele Substation reliability issues and recommended installing the 138 kV partial overhead, partial underground transmission line over installing DG because of economic and practical reasons.

Q. What were some of the practical issues in analyzing DG on the T&D system?

A. Practical issues included the availability of land in the area of installation required to mitigate the identified T&D problem, the development of fuel supply and maintenance resources, interconnection requirements, permitting issues, and the ability to use existing "emergency" back-up generators for the purpose of resolving T&D problems.

Q. Did HECO conduct a more recent analysis for EOTP?

A. Yes, the 2003 Koolau/Pukele Overload Options Study completed in December 2003 analyzed the effectiveness of DG to address the Koolau/Pukele line overload situation. (Reference Docket No. 03-0417, HECO T-4, pages 81-83.) The study recognized that the application filed with the PUC for approval for an aggressive

CHP program and/or the ability to install approximately 19 MW (only half of the required amount needed to defer the Koolau/Pukele overload) would reduce the rate of load growth that had to be served from central station generation (and decrease the use of the T&D system, but was not practical due to space and permitting issues, and cost.

Q. Explain how distributed generation was incorporated into the 7200/7300 HELCO Line Overload Analysis.

A. HELCO is at risk of transmission line overload situations on the Keahole-Keamuku (6800) 69 kV transmission line, Waimea-Keamuku (7200) 69 kV transmission line and Waimea-Ouli (7300) 69 kV transmission line under single-line contingency situations. These transmission line overloads were identified in HELCO's Application for Approval, Docket No. 03-0388 (Kailua Capacitor Addition), Exhibit IV. A new study was initiated focusing on the 7200 and 7300 line overloads as a result of the analysis performed for Docket No. 03-0388, Exhibit IV and analysis for the 7200/7300 HELCO Line Overload Study is still in progress. DG at HELCO Substations and utility-owned CHP installations in Kona and Hilo are being evaluated in the study. Excerpts from that study, which is in draft form and subject to change, were provided in response to CA-SOP-IR-15. The conclusions of the analysis are (1) that it is not realistic to assume that HELCO will be able to site the necessary DG units to prevent the line overload situation at HELCO-owned substation sites on the Kona coast and (2) there will not be sufficient utility-owned CHP installed early enough to reduce the line overload on the 7300 line as a result of the 7200 line contingency and that it may require years (~2016) before the utility-owned CHP installations to match the utility-owned CHP requirements.

Q. Were diesel generators installed in North Kohala on the Big Island as part of HELCO's Contingency Plan?

A. No, in 1995, HELCO submitted an application to the PUC for the installation of two nominal 2.2 MW diesel generators on a 2.9-acre parcel of industrial-zoned land at the old mill site in North Kohala. (Docket No. 95-0333) These units would provide generation capacity and would also improve the quality and reliability of electrical service by providing back-up generation to the local area if the 34.5 kV radial sub-transmission line experienced an outage. The project was designed to operate during contingency situations and non-covered source air permits with annual fuel limits were sought. The project was not pursued primarily due to opposition to the project from certain community groups.

Customer-sited CHP

Q. How are customer-sited CHP incorporated into T&D planning studies?

A. In general, customer-sited CHP is incorporated into the T&D planning studies through the Company's load forecast. CHP impacts are subtracted from the load forecast on a system-wide basis. The EOTP analysis also analyzed CHP in areas where T&D line overloads could be addressed. Analysis for the 7200/7300 HELCO Line Overload also included a system-wide CHP forecast and analyzed the amount of CHP required to mitigate the line overloads.

Q. Can the utility consider targeting DG and CHP installations in an area where there are identified criteria violations or reliability concerns?

A. Targeting CHP installations in an area where there are identified criteria violations or reliability concerns requires the evaluation of additional CHP installations in the service areas beyond the level expected to result from current programs and efforts. In concept, evaluation of DG and CHP installations can be analyzed on a case-by-case basis, however, there are a number of issues to consider including: (1) DG diversity issues and T&D peak load planning, (2) timing of DG and CHP installations may not coincide with the Company's requirements, (3) the customer's commitment to the operation and maintenance of DG and CHP units, (4) customers will only install DG and/or CHP if it is cost-effective, and (5) there are practical issues with DG and CHP installations.

Q. Explain the first issue on DG diversity and T&D peak load planning.

A. The Company generally plans based on the peak load forecast under various contingency conditions. Depending on the situation being analyzed, the day peak or the evening peaks are considered. Therefore, it cannot simply be concluded that the load-carrying requirements on the line feeding the customer with DG facilities would be reduced. The extent of the installation of multiple DG units would depend on factors such as the relative sizes of the units, the reliability characteristics (e.g., forced outage rates) of the units and the ability of the utility to coordinate scheduled maintenance or to require that scheduled maintenance takes place during off-peak periods (as a result of contractual agreements with enforcement provisions). The load-carrying requirements would not be reduced to the extent that the utility still has to plan to carry the entire load when the DG is off-line.

Q. How many DG facilities are required to "create diversity" to where DG facilities are realized?

A. Specific analysis to determine the number and/or size of DG facilities that would be required to create diversity has not be conducted however, diversity can be illustrated conceptually by the following example. If there is a single DG on a circuit to serve a particular load, there will be times when that DG will be unavailable due to a planned or forced outages. In this case, there is no diversity and the grid must provide backup to the DG, in which case the need for firm system capacity would not be deferred. If there are multiple DGs on that circuit, there may still be times when the combined output of the DGs may be zero due to a combination of planned and forced outages. However, the probability of the combined output being zero is reduced. That probability will be a function of the number of DGs, the DG unit sizes, their planned outage requirements and their forced outage rates.

Q. Why would the timing of DG on customer sites and CHP facilities not necessarily coincide with the Company's need to resolve T&D criteria violations and/or reliability concerns?

A. The installation of on-site DG controlled by the customer and installation of CHP cannot be fully controlled by the utility as compared to installing DG at the Company's substations, where the installation, operation and maintenance of the units can be controlled more than an on-site DG or CHP facility. Customers may have other criteria in mind when they determine whether to install DG on-site or CHP. For instance, most commercial customers will be drawn to implement DG or CHP during periods when the existing building of a business is expanding, with the installation of a new facility, or at a point in time where large pieces of equipment such as the air-conditioning system need to be upgraded or replaced. The time frame for the customer to implement DG and/or CHP facilities may not necessarily coincide with the utilities need to resolve T&D criteria violations or reliability concerns.

Q. Are there issues with third-party CHP and utitility-owned CHP that need to be considered in the planning analyses?

A. Yes, to some extent, the Company may have a little more control over a utility-owned CHP facility over a third-party CHP facility because it would have access to data which can determine how the facility will be operated, the utility is responsible for the maintenance of the facility and can maintain it based on utility standards to increase reliability rather than only consider costs, which may be the case for a third-party CHP facility, and maintenance of many units can be coordinated to provide diversity.

Q. Why is the customer's commitment to the operation and maintenance of DG and CHP units an issue?

A. Contractual agreements are not in place between the utility and the third-party CHP facility and the commitment towards operating and maintaining a reliable facility is uncertain. For instance a CHP facility could be shut-down for maintenance during the peak conditions where the facility is needed most to address T&D concerns.

Q. Based on past DG analysis, is it cost-effective to install DG facilities specifically for addressing T&D criteria violations or reliability concerns?

A. Installing targeted DG facilities for the sole purpose of addressing T&D criteria violations or reliability concerns even if it is feasible, may not be cost-effective. For instance the analysis for the EOTP showed that costs to install DG and CHP to address only the Koolau/Pukele line overload situation exceeded the cost of installing transmission system upgrades on the 46 kV system. The relocation of the Lanai City diesel generators was a cost-effective solution, however, the diesel generators being used were already scheduled to be retired, which contributed the relatively low relocation costs. Other analyses on the HECO and MECO system have considered new generation installations to mitigate T&D problems.

Q. What other practical issues should be considered with targeted DG and CHP?

A. Other practical issues with targeted DG and CHP include inadequate land sites on customer or residential property where the DG and CHP is required to address T&D criteria violations and/or reliability concerns and the ability to permit the units to operate in the manner that will reduce the load.

Installing Emergency Generators

Q. How do emergency generators affect the reliability of the T&D system?

A. The concept of operating onsite emergency generators was explained as the "virtual power plant" in Mr. Sakuda's testimony, HECO T-3. One of the issues identified in Mr. Sakuda's testimony is that onsite emergency generators operate very few hours per year and therefore may be able to address transmission concerns during contingency situations rather than for continuous operation. However, Mr. Sakuda also explained that backup or emergency generators are normally installed by large customers to provide electrical power to their essential services (such as emergency lighting and critical electronic equipment) in the event power from the utility is not available and that it is likely that when there is a system emergency and the utilities need backup power from such "virtual" power plants, the large customers would be affected by the same system emergency and would be calling upon their emergency generators to provide power. In such cases, the "virtual" power plants would not be able to provide backup power to the grid and there is no increase in reliability to the T&D system. There may be an increase in reliability to the individual customer with the onsite emergency generator.

CONCEPTUAL OVERVIEW OF T&D AVOIDED COST CALCULATION

Avoided Costs

Q. What are avoided costs in the context of this proceeding?

A. If after considering the various issues, a DG installation is feasible, avoided costs to determine the cost-effectiveness of the DG facility can be calculated. As stated in Mr. Sakuda's Testimony, HECO T-3, avoided costs are the incremental or additional costs to the utility of electric energy or firm capacity or both which costs the utility would avoid as a result of the installation of distributed generation. In general, avoided costs can consist of several components:

1) avoided generation capital costs;
2) avoided generation fixed operation and maintenance ("O&M") costs;
3) avoided energy costs;
4) avoided variable O&M costs;
5) avoided transmission capital costs;
6) avoided transmission loss costs;
7) avoided distribution capital costs; and
8) avoided distribution loss costs.

My testimony will cover the last four items. Items 1-4 were covered by the testimony of Mr. Sakuda in T-3.

Q. In general, what types of avoided costs are considered for the T&D system?

A. In concept, depending on the specific project, the two types of avoided costs on the T&D system are the deferral value and the replacement value. Replacement avoided costs can occur when the investment on the T&D system will not be made because DG facilities have been installed as explained later in my testimony. If an investment on the T&D system is only shifted back in time, but not eliminated, the avoided cost is defined as a deferral avoided cost. In concept, transmission capital avoided cost calculations will typically represent deferral avoided costs since it may take large amounts of DG installations to resolve transmission concerns. Distribution capital avoided cost calculations could result in either a deferral or a replacement avoided cost and an example of these will be explained later in my testimony.

Avoided Transmission Capital Costs

Q. Explain the concept of avoided transmission capital costs?

A. Avoided transmission capital costs are those capital costs associated with the installation of transmission facilities that can be avoided by deferring the installation date of the proposed transmission facilities. Firm DG capacity added to the system can defer the need for new firm utility central station generating capacity. This deferral can defer the need to install transmission facilities associated with the installation of new firm utility central station generating capacity and can result in avoided transmission capital costs. Multiple DG unit installations in one area may reduce the load demand in a geographic area or may be able to provide new generation to match the load growth rate of an area. Reducing the load demand in an area or providing new generation to match the load growth rate of an area may be able to defer the proposed transmission facilities required to serve the increasing load demand.

Q. How are avoided transmission capital costs calculated?

A. Transmission plans and costs for additional transmission facilities can be developed for a base case, which represents probable long-term assumptions, by simulating the utility grid using a load flow program and applying transmission planning criteria. The Transmission Planning process was explained earlier in my testimony. Transmission plans and costs for additional transmission facilities can be developed for the alternate case assumptions, which would include DG facilities at specific sites. The base case transmission capital costs are subtracted from the alternate case transmission capital costs to calculate the avoided transmission capital costs.

Avoided Transmission Loss Costs

Q. What are avoided transmission loss costs?

A. Conceptually, avoided transmission losses are those utility losses that would not be incurred as a result of the generation of electricity by some other source. Energy produced by DG can displace the energy that would otherwise be produced by utility central station generating units and can result in avoided transmission loss costs.

Q. What are transmission losses?

A. As power is transported over the transmission system, losses occur due to the resistance of the conductor to transport the power which is commonly referred to as the impedance characteristics of the transmission line conductor. Losses can be calculated by the formula I^2 x R or in other words, the amount of current flowing through the transmission lines times itself times the impedance characteristics of the line represented as "R". The current flowing through the transmission lines will change in every instance depending on the load demand and the generation on the system.

Q. How is the current in a transmission line calculated?

A. As explained earlier, the PSS/E load flow program is used to simulate current flows and voltages on the utility electrical grid for planning scenarios. Transmission line currents result from having the PSS/E program solve a series of equations, which represent the transmission system and on-line generation.

Q. How does DG affect the current flowing through a transmission line?

A. In concept, DG units can be connected to the distribution system and serve the local load connected to the DG facility. This reduces the power output needed from central station generation and therefore reduces the amount of power flowing through the transmission line. However, it is important to note that the DG facility needs to be installed and running in order to realize a reduction in power flow through the transmission system.

Q. How does the PSS/E load flow program calculate the amount of losses on the system?

A. Load flows can simulate historical conditions by entering the historical loads and generating units on the system, or it can simulate future systems by scaling the historical loads and dispatching present and future generators on the electrical grid. The simulations produce the currents through the transmission lines and the program also calculates the amount of losses that occur for each load flow in MW. This MW value is referred to as the loss demand. Several load flows are simulated to calculate the loss demand values at various load levels. The transmission system load flows capture losses on the HECO generator step-up transformer losses, the transmission line losses and the sub-transmission losses (including losses from the transformation of power from the transmission voltage level to the sub-transmission voltage level). Curve fitting techniques using a quadratic function is used to form a loss curve, which will show the resulting demand loss for a given load level. The loss function is then numerically integrated using a load duration curve that is representative of the utility system to calculate the energy losses in MWh

Q. How are avoided transmission line loss costs calculated?

A. The methodology described above can be implemented for two cases. Base case load flows can be simulated to calculate the base case loss function and the resulting base case energy losses in MWh for each year of study. Transmission line loss costs can be calculated by multiplying the yearly losses by the average fuel cost, which are calculated using production simulations described in Mr. Sakuda's testimony, HECO T-3. Alternative case load flows, with DG can be simulated to calculate the alternate case loss function, alternate case energy losses and resulting alternate case energy loss costs using the alternate case production simulations described in Mr. Sakuda's testimony HECO T-3. The base case transmission line loss costs are subtracted from the alternate case transmission line loss costs to calculate the avoided transmission line loss costs.

<u>Avoided Distribution Capital Costs</u>

Q. What are avoided distribution capital costs?

A. In concept, avoided distribution capital costs are similar to avoided transmission capital costs and include capital costs associated with the installation of distribution facilities that can be avoided by deferring the installation date of the proposed distribution facilities or eliminating the need to install distribution facilities.

Q. How can avoided distribution capital costs be calculated?

A. Distribution plans and costs for additional distribution facilities can be developed for a base case, which represents probable assumptions without the distributed generation source being analyzed, by calculating forecasted transformer loading and distribution circuit loading. The calculation can determine if the expected load exceeds the capacity of the transformer or distribution circuit rating.

Improvements to the system and their associated costs, which could resolve the criteria violations, are identified. An alternate case with the distributed generation source can be analyzed to determine transformer loading and distribution circuit loading. In some cases, the distributed generation source could lower the loading on the existing transformer and distribution circuit and no further upgrades would be required or may be deferred. The base case distribution capital costs are subtracted from the alternate case distribution capital costs to derive the avoided distribution capital costs.

Q. Provide some example of distribution avoided costs and how costs can be deferred or replaced.

A. In concept, if DG facilities are installed to match new customer loads or customer increases in power consumption then T&D facilities will not be required because the grid will not see the added load. In this instance, the entire cost to build the T&D facilities to serve the customer can be avoided and are classified as a replacement avoided costs. If for instance DG facilities are being installed to try to match new customer load and the growth rate in the area suddenly increases beyond the capacity of the DG installations then T&D facilities may need to be installed to account for the differences. The DG installations in this instance served to defer T&D upgrades. Therefore if planning a system in this manner, it is important to recognize that there may be some risks involved. Insuring the forecasts for the areas are accurate are important and are difficult although necessary in order to avoid mismatches between DG and load demand because installing T&D facilities to resolve the mismatches take time to implement.

Q. Will most DG projects incur avoided distribution capital costs?

A. Most DG projects will have zero avoided distribution capital costs because DG projects are driven by customer choice as explained in the section describing the targeted DG issues. DG projects may or may not be a part of the system where distribution upgrades are required.

Avoided Distribution Loss Costs

Q. What are avoided distribution loss costs?

A. In concept, avoided distribution losses are those utility losses that would not be incurred as a result of the generation of electricity by some other source. Energy produced by DG can displace the energy that would otherwise be produced by utility central station generating units and can result in avoided distribution loss costs. It should be noted, however that export of energy from DG to other customers may only lower transmission losses and could still incur some distribution losses.

Q. How can distribution losses be calculated?

A. Distribution demand losses can be calculated using various simulation tools as explained in HECO-409. Curve fitting techniques, which are the same as used for the transmission loss calculation, using a quadratic function can be used to form a loss curve, which will show the resulting demand loss for a given load level. The loss function can then numerically integrated using a load duration curve that is representative of the utility system to calculate the energy losses in MWh. HECO-409 applies to the HECO system. A similar methodology on the distribution system for HELCO and MECO can be incorporated, however, instead of running distribution load flows, typical distribution feeder data and the current flowing from the 69 kV transformer to the distribution level voltage is used to calculate the I^2R losses for line flows are used.

Q. How can avoided distribution losses be calculated?

A. Distribution losses can be calculated for a base case without DG and an alternative case with DG. The alternate case losses are subtracted from the base case losses to calculate the avoided distribution losses. The loss costs are calculated by multiplying the yearly losses by the average fuel cost, which are calculated using production simulations described in Mr. Sakuda's testimony, HECO T-3.

IMPACT OF DG ON THE POWER QUALITY OF THE T&D SYSTEM AND DG INTERCONNECTIONS

T&D System Power Quality

Q. What impacts do DG facilities have on T&D system power quality?

A. The impact of DG facilities on T&D power quality can be very complex and can require detailed studies on a case-by-case basis. Tariff Rule 14H establishes how the interconnection of a DG system is to be handled. However, there are practical limits to the amount of DG on distribution circuit, which varies depending on the specific circumstances of each circuit.

Q. Why is the impact of DG facilities on T&D power quality very complex?

A. The impact of DG located at customer facilities is dependent on location specific issues such as the following:

- configuration of the distribution system, radial vs. network
- length of distribution lines
- penetration of distributed generation on the primary circuit and the back up circuit
- reliability and redundancy of customer systems
- synchronous or induction generation
- grounding of transformers and other equipment
- short circuit characteristics of the distribution circuit.

For example, the DG interconnections can cause an increased risk of voltage regulations problems, adverse interactions with the utility's protection system and unintended islanding as the penetration DG capacity increases on a utility distribution feeder. Therefore, Rule 14H, which is explained later in my testimony, provided a need for additional technical study for non-utility owned distributed generation to examine the risk of these problems when the aggregate generating capacity per distribution feeder exceeds 10% of the peak annual KVA load of the feeder.

Q. How does DG cause voltage regulation issues?

A. According to a February 2002 Electric Power Research Institute ("EPRI") Technical Update titled "Integrating Distributed Generation Into the Electric Distribution System," ("February 2002 EPRI Technical Update") DG can create unusually high voltage (or in some cases, unusually low voltages) depending on the size of the DG and the distribution circuit characteristics at the installation location. When real power is injected into the power system, the voltage at the point of injection will increase, in proportion to the size of the DG (either individual or in aggregate). Conversely, if a DG point of interconnection is near a substation voltage regulator, low voltages could occur at the end of a long radial feeder. Therefore additional technical studies may be required in order to determine the impact of DG with respect to voltage regulation. Low or high voltages in the local area can affect customer equipment connected to the distribution line experiencing the low or high voltages.

Q. How does the installation of DG adversely impact the utility's protection schemes?

A. Preliminary analysis on the HELCO system shows that the use of synchronous DG/CHP generation can help with voltage recovery due to their ability to field force, and could improve voltages in the localized area. If synchronous DG/CHP generating units are unable to ride through low voltage situations, however, the DG/CHP units could trip off, which would result in slower voltage recovery after a voltage collapse and the possibility of interrupting customers due to underfrequency load shedding on the HELCO and MECO utility grids because these grids operate with quick-start diesels vs. carrying spinning reserve such as the HECO system. In addition, the use of induction DG/CHP generation slows voltage recovery due to drawing increased reactive power during voltage collapse conditions. The February 2002 EPRI Technical Update also explains that the installation of DG if not done properly could result in unintended tripping of protective relaying devices. The update explains that, in order to prevent this, DG must follow safe and reliable interconnection and operating practices, including coordination with the circuit breaker settings, recloser practices and fusing of the utility's distribution system. The DG facility should be available to operate during normal utility system conditions and safely disconnect and reconnect from the utility system when the need arises such as during contingencies. When the utility system is under maintenance, the DG system must either disconnect from the utility system and/or be isolated from the grid to insure the safely of utility personnel performing the work on the de-energized utility system. Also the preferred specification for relaying should be what is referred to as a "utility grade" relay which meets ANSI/IEE surge withstand capabilities, has high accuracy in pickup and time settings and has a testable interface. The definition of utility grade was defined on Sheet No. 34B-5 of Rule 14H.

Q. Please explain what is meant by unintended islanding.

A. Islanding is defined in Rule 14H as a condition in which one ore more generating facilities deliver power to a utility customer or customers using a portion of the utility's distribution system that is electrically isolated from the remainder of the utility's distribution system. Unintended islanding according to Rule 14H may occur following an unanticipated loss of a portion of the utility distribution system. Some of the dangers with unintended islanding include public and utility personnel safety and to prevent possible damage to customer equipment.

<u>Rule 14H</u>

Q. Please explain Rule 14H.

A. The Company's revised Tariff Rule Nos. 14H were approved on March 6, 2003 by Decision and Order No. 20056. In D&O 19773, the purpose of and the key section of these standards were summarized:

"Appendix I sets forth comprehensive interconnection standards and technical requirements that are intended to facilitate the interconnection and parallel operation of a customer's distributed generating facility with the utility's electrical system. The underlying purposes of the technical interconnection requirements are to: (1) maintain safety, reliability, and power quality and restoration; (2) protect the utility's and customer's equipment and facilities; and (3) advance the operating efficiencies of the utility's electrical system.

In general, the interconnection standards and technical requirements consist of: (1) a definitions section; (2) general interconnection guidelines; (3) design requirements; (4) operating requirements; (5) technology specific requirements; and (7) schematic diagrams illustrating "typical equipment and protective device requirements for large synchronous, induction and inverter generators".

Q. What is the definition of parallel operation?

A. Parallel operation occurs when the customer installs a DG facility for electricity power purposes only and can either export or not export power to the Company's.

Customer-sited generation operated in parallel with the Company's grid differs from off-grid, customer-sited generation because the customer facility requires back-up power from the utility and therefore the customer is still electrically connected to the Company's grid. Off-grid, customer-sited generation is not electrically connected to the Company's grid and the customer does not require back-up power from the Company. Rule 14H outlines the interconnection agreement procedures and the technical review process for generators operating in parallel with the Company's grid and provides interconnection requirement standards for DG facilities that do not export power to the utility.

Q. If Rule 14H provides standard interconnection requirements, why would a customer facility exporting to the Company's grid require additional technical study if the facility could meet the standard interconnection requirements set forth in Rule 14H?

A. As stated earlier, Rule 14H was designed to provide interconnection standards for customer-sited generation operating in parallel to the utility grid. Exporting power onto the utility grid will change the direction of power flow on the Company's T&D system. The impact of DG facilities located at customer sites is dependent upon location specific issues described earlier in my testimony. Therefore, given the various factors, the power quality and reliabilities impact of a specific distributed generator is dependent upon an individual site and should be evaluated on a case-by-case basis.

SUMMARY

Q. Please summarize your testimony.

A. My testimony covered the impact of DG and CHP on the reliability of the T&D

system. Both T&D and non-T&D alternatives such as DG can be used to address identified T&D criteria violations or address reliability concerns. Different forms of DG have already been incorporated into T&D studies such DG units installed at substations, installation of onsite CHP systems and if issues on availability are resolved, backup emergency generators, which could be used to address T&D concerns during contingency situations. In concept planning studies can and have analyzed targeted DG, beyond the level expected from current DG programs, on a case-by-case basis although issues on DG diversity, DG timing, customer commitment to DG, cost-effectiveness of DG and other practical issues with incorporating DG into the planning analysis must be considered. If the issues related to DG are addressed, in concept avoided T&D cost calculations can be performed to determine the cost-effectiveness of the DG options. In addition, analyzing the impact on the power quality of the T&D system is location specific, complex, and must be studied on a case-by-case basis and is analyzed through a standardized interconnection process, referred to as Rule 14H, which was approved by the Commission on March 6, 2003 by Decision and Order No. 20056.

Q. Does this conclude your testimony?

A. Yes, it does.