Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

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February 26, 2010

Darcy L. Endo-Omoto
Vice President
Government & Community Affairs

The Honorable Chairman and Members of the
Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Adequacy of Supply
Hawaiian Electric Company, Inc. ("Hawaiian Electric")

The following information is respectfully submitted in accordance with paragraph 5.3a. of General Order No. 7[1] which states:

> *The generation capacity of the utility's plant, supplemented by electric power regularly available from other sources, must be sufficiently large to meet all reasonably expectable demands for service and provide a reasonable reserve for emergencies. A Statement shall be filed annually with the Commission within 30 days after the close of the year indicating the adequacy of such capacity and the method used to determine the required reserve capacity which forms the basis for future requirements in generation, transmission, and distribution plant expansion programs required under Rule 2.3h.1.*

1. Peak Demand and System Capability in 2009

Hawaiian Electric's 2009 system peak occurred on Wednesday, October 7, 2009, and was 1,260,000 kW-gross or 1,213,000 kW-net based on net Hawaiian Electric generation, net purchased power generation, the peak reduction benefits of energy efficiency demand-side management programs, and with several cogenerators[2] operating at the time. Had these

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[1] Hawaiian Electric's Adequacy of Supply ("AOS") Report is due within 30 days after the end of the year. On January 20, 2010, Hawaiian Electric requested an extension of time, to no later than February 26, 2010, to file its AOS Report to allow it to better assess and incorporate the impacts of its most recent generation availability experience to determine the estimated reserve margin capacity situation for the period covered by this letter. The Commission granted Hawaiian Electric's extension by letter dated February 18, 2010.

[2] At the time of the peak, certain units at Tesoro, Chevron, and Pearl Harbor were generating an estimated 24,000 kW of power for use at their sites.

cogenerating units not been operating, the 2009 system peak would have been approximately 1,284,000 kW-gross or 1,237,000 kW-net.

Hawaiian Electric's 2009 total generating capability of 1,785,100 kW-net includes 434,000 kW-net of firm power purchased from (1) Kalaeloa Partners, L.P. ("Kalaeloa"), (2) AES Hawaii, Inc. ("AES"), and (3) H-POWER. Also included in this capability is 29.5 MW of temporary, Hawaiian Electric-sited, distributed generation.

Hawaiian Electric's Campbell Industrial Park Combustion Turbine Unit 1 ("CIP CT-1" or "CT-1") was completed and placed in service (i.e., tied into the electrical grid and producing power) on August 3, 2009. On February 19, 2010, the Commission issued a Second Interim Decision and Order ("D&O") in Docket No. 2008-0083 (Hawaiian Electric Test Year 2009 Rate Case). In the Second Interim D&O, the Commission stated, among other things:

> Based on the totality of the circumstances, the commission finds that HECO is probably entitled to include CIP CT-1 in its rate base as plant in service given that the unit was connected to the grid in the test year, and is available to provide electricity to address the reserve margin shortfall situation and provide blackstart capability; and given HECO's recent efforts and commitment to expeditiously obtain a biofuel supply. [page 17]

The Commission stated further:

> Accordingly, until HECO can secure its biodiesel supply requested in Docket No. 2009-0353, the commission finds it appropriate to temporarily allow HECO to operate CT-1 as a diesel peaking unit. This will allow the unit to be utilized on more than just an emergency basis thereby benefiting the ratepayer. [page 19]

As a result, Hawaiian Electric will use CT-1 to economically meet system spinning reserve requirements or to meet demand using diesel fuel, if biofuel is not available, and within the requirements of the Covered Source Permit (air permit).

Because CIP CT-1 was available for service at the time the peak occurred, the capacity available from the unit is included in the reserve margin calculation for 2009. Oahu had a reserve margin of approximately 51% over the 2009 adjusted system net peak.[3] The capacity available from CIP CT-1 is also included in the generating system reliability calculations that are discussed later in this report.

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[3] The reserve margin calculation takes into account the approximately 54,000 kW of interruptible load served by Hawaiian Electric.

Hawaiian Electric also has power purchase contracts with three as-available energy producers. Since these contracts are not for firm capacity, they are not reflected in Hawaiian Electric's total firm generating capability.

2. Estimated Reserve Margins

Appendix 1 shows the expected reserve margin over the next five years, 2010 to 2014, based on Hawaiian Electric's December 2009 update to the Sales and Peak Forecast, and includes estimated energy efficiency demand-side management ("DSM") impacts and forecasted load management DSM impacts.

3. Analysis of Hawaiian Electric's Adequacy of Supply

Hawaiian Electric's capacity planning criteria are applied to determine the adequacy of supply and whether or not there is enough generating capacity on the system. Hawaiian Electric's capacity planning criteria take into account that Hawaiian Electric must provide for its own backup generation since, as an island utility, it cannot import emergency power from a neighboring utility. Hawaiian Electric's capacity planning criteria are described in Section 3.1.

The results of the annual analysis of the adequacy of supply on the Hawaiian Electric system are a function of a number of forecasts, such as:

- peak demand, including the forecasted peak reduction benefits of (a) energy efficiency demand-side management programs, (b) net energy metering, and (c) customer-site photovoltaic ("PV") installations; [§4.1]
- peak reduction benefits of load control programs; [§4.2]
- planned maintenance schedules for the generating units on the system; [§4.3]
- Equivalent Forced Outage Rates ("EFOR") on the generating units; [§4.3]
- additions of firm generating capacity; [§4.4] and
- reductions of firm generating capacity. [§4.5]

Each of the current assumptions for these factors is discussed in Section 4. As with all forecasts, these elements are subject to uncertainties. Therefore, a range of scenarios were considered in the analysis.

3.1 Hawaiian Electric's Capacity Planning Criteria

Hawaiian Electric's capacity planning criteria consist of two rules and one reliability guideline. The reserve capacity shortfalls calculated herein are determined by the application of the reliability guideline based on various key inputs such as the EFORs of each generating unit, the load to be served, the amount of capacity on the system and the availability of the generating units.

Rule 1:

The total capability of the system plus the total amount of interruptible loads must at all times be equal to or greater than the summation of the following:

a. *the capacity needed to serve the estimated system peak load;*

b. *the capacity of the unit scheduled for maintenance; and*

c. *the capacity that would be lost by the forced outage of the largest unit in service.*

Rule 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 two rules include load reduction benefits from interruptible load customers. Because Hawaiian Electric will not build reserve capacity to serve interruptible loads, interruptible load programs such as Hawaiian Electric's current Rider I and load management programs can have the effect of deferring the need for additional firm capacity generation.

Rules 1 and 2 are deterministic in nature, meaning that the adequacy of supply can be determined through simple additions or subtractions of capacity without regard to the probability that the capacity will be available at any given time. For example, to determine whether or not Rule 1 would be satisfied at a given point in time, one would take, in MW, the total capacity of the system, add the total amount of interruptible loads that would be available for interruption at that time, subtract the capacity of the unit or units that are unavailable due to planned maintenance, subtract the capacity of the largest available unit, and determine whether the result is greater than or less than the system peak at that time. If the result is greater than the system peak, Rule 1 would be satisfied and no additional firm capacity would be needed. If the result is less than the system peak, Rule 1 would not be satisfied and additional firm capacity would be needed. The likelihood (or probability) that the largest unit will be lost from service during the peak is not a factor in the application of this rule.

Rule 2 takes into account the amount of quick load pickup that must be available at the time of the peak to avoid shedding load from the system in the event the largest loaded unit is unexpectedly lost from service. Rule 2 is also deterministic in nature. It does not take into account the probability that the largest unit will be lost from service during the peak.

3.2 <u>Hawaiian Electric's Reliability Guideline: Loss of Load Probability ("LOLP")</u>

The application of Hawaiian Electric's generating system reliability guideline does take into account the probabilities that generating units could be unexpectedly lost from service.

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."

In order to determine whether there is enough capacity on the system to account for the probability that multiple units may be unexpectedly lost from service, the result of an LOLP calculation must be compared against Hawaiian Electric's generating system reliability guideline.

Hawaiian Electric has a reliability guideline threshold of 4.5 years per day. Hawaiian Electric plans to have sufficient generating capacity to maintain generating system reliability above 4.5 years per day. There should be enough generating capacity on the system such that the expectation of not being able to satisfy demand due to insufficient generation occurs no more than once every 4.5 years. Values less than 4.5 years per day indicate lower levels of reliability and an increased likelihood of generation-related customer outages.

One potential means to address the ever increasing planning uncertainty and complexity is to revise the capacity planning guideline. If the existing Loss of Load Probability of 4.5 years per day does not provide an adequate margin to respond to quickly-changing parameters, such as changes in peak demand and individual unit availability factors, many of which may change rapidly from year to year, then the utility could plan for a higher reliability standard similar to that of many mainland utilities.

Such an approach would not eliminate quickly-changing parameters, but it would add a measure of conservatism in recognition that the uncertainties undoubtedly exist.

In its direct testimony for the Campbell Industrial Park Generating Station and Transmission Additions Project (Docket No. 05-0145), filed on August 17, 2006, the Consumer Advocate stated:

> [HECO's reliability guideline] is less stringent than the guidelines used by mainland utilities. As will be addressed later in my testimony, this guideline should be re-evaluated to determine if it should be more stringent in the future (e.g., one day in 6 years) to ensure reliable service. However, this determination should be based on analyses that assess the tradeoff between electric service costs to the consumer and the increase in reliability to be gained. CA-T-1 at 32.

In its future planning processes, Hawaiian Electric will explore the implications (including cost implications) of increasing its reliability guideline to a higher threshold of 10 years per day. A scenario analysis of the reserve capacity shortfall based on this threshold is included in Section 5.

Please refer to Appendix 3 of the 2005 AOS for additional information related to Hawaiian Electric's reliability guideline.

4. Key Inputs to the 2010 AOS Analysis

4.1 December 2009 update of the Sales and Peak Forecast

Hawaiian Electric developed a short-term sales and peak forecast update in December 2009 ("December 2009 forecast"), which was subsequently adopted by the Company.

Figure 1 illustrates Hawaiian Electric's historical system peaks and compares them to forecasts used in the 2009 AOS, and the 2010 AOS analysis. The analyses contained in the 2009 AOS were based on a September 2008 sales and peak forecast. For both the recorded and forecast data, the figures reflect an upward (stand-by) adjustment to account for the potential need to serve certain large customer loads (Chevron, Tesoro and Pearl Harbor) that are frequently served by their own internal generation. Figure 1 also includes the peak reduction benefits of (a) energy efficiency DSM programs, (b) net energy metering, and (c) customer-site photovoltaic installations. Table 1 compares the historical, 2009 AOS and 2010 AOS forecasts and projections. The comparison between forecasts indicate the degree to which key planning assumptions such as the peak forecast can quickly and unexpectedly change.

Subsequent to filing the 2009 AOS in February 2009, Hawaiian Electric developed a new, May 2009 sales and peak forecast. This forecast was substantially lower than the September 2008 sales and peak forecast. However, in the latter part of 2009, it was observed that the actual recorded monthly sales and peaks were significantly exceeding the monthly peaks in the May 2009 forecast and were more closely tracking the monthly sales and peaks in the September 2008 forecast. Therefore, the December 2009 forecast was produced to update the forecast of sales and peaks to more closely track sales and peak demand experienced in the second half of 2009.

Figure 1: Recorded Peaks and Future Year Projections

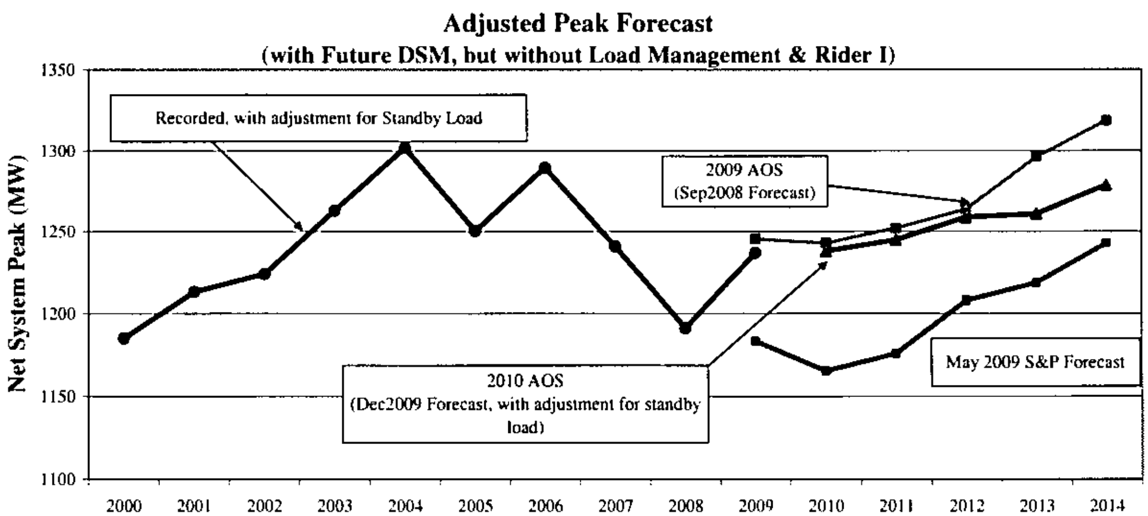

Table 1: Recorded Peaks and Future Year Projections

Net System Peak (MW) (with Future DSM, but without Load Management & Rider I)						
Year	Actual	Actual Adj for Standby	2009 AOS Sep 2008 S&P	May 2009 S&P	2010 AOS Dec 2009 S&P	Difference 2010-2009 AOS
2000	1164	1185				
2001	1191	1213				
2002	1204	1224				
2003	1242	1262				
2004	1281	1299				
2005	1230	1250				
2006	1265	1288				
2007	1216	1241				
2008	1186	1191				
2009	1213	1237	1,246	1,183		
2010			1,243	1,165	1,238	-5
2011			1,252	1,176	1,245	-7
2012			1,264	1,208	1,259	-5
2013			1,296	1,219	1,261	-35
2014			1,319	1,243	1,279	-40

4.2. Projected Peak Reduction Benefits of Load Control Programs

Effective July 1, 2009, the administration of Hawaiian Electric's energy efficiency DSM programs was transferred to the Hawaii Energy Efficiency Programs ("HEEP") Administrator. Therefore, energy efficiency program impacts for customers who participated in the programs prior to July 1, 2009 are based on Hawaiian Electric's records. Projected long-term energy efficiency DSM impacts reflected in the AOS analyses are based on the utility's estimates developed prior to July 1, 2009. Adjustments to the long-term projection will be made as further information becomes available from the third party administrator.

Hawaiian Electric continues to administer the Commercial & Industrial Load Control ("CIDLC") and Residential Direct Load Control ("RDLC") programs, which were not transferred to a third-party administrator. However, in its Decision and Orders in Docket Nos. 2009-0073 and 2009-0097, dated December 29, 2009, for the CIDLC and RDLC Programs, respectively, the Commission extended the programs through December 31, 2012, but denied Hawaiian Electric's request, without prejudice, to expand the programs at this time. Hawaiian Electric intends to provide program documentation that responds to the Commission's concerns expressed in the Decision and Orders and also plans to request Commission approval for expansion of these programs. For the purposes of the AOS Report, Hawaiian Electric has reflected no program expansion per the Commission's instructions, and assumes that the programs will remain in effect at the current levels of participation for the duration (2010-2014) of this analysis.

As of December 31, 2009, Hawaiian Electric has approximately 24.1 MW (net generation level) of controlled load under its CIDLC program, and approximately 25.5 MW (net generation level) of controlled load under its RDLC program. Table 2 shows the assumption of the peak reduction benefits of the load management programs[4]

Table 2: Projected CIDLC, RDLC and Rider I Impacts (MW)[5]

Year	RDLC	CIDLC	Rider I	Total
2010	26	24	4	54
2011	26	24	4	54
2012	26	24	4	54
2013	26	24	4	54
2014	26	24	4	54

4.3. Hawaiian Electric Generating Unit Forced, Planned and Maintenance Outages

Forced outages and de-ratings reduce generating unit availability and are accounted for in the EFOR statistic. Planned outages and maintenance outages also reduce generating unit availabilities.

The schedules for planned overhaul and maintenance outages change frequently due to unforeseeable findings during outage inspections or to changes in priorities due to unforeseeable problems. When extensions to planned outages occur, or problems are discovered such that an outage is needed to address it, or if forced outages occur, the Planned Maintenance Schedule must be revised.

Table 3 provides recorded Hawaiian Electric EFOR data by unit for the period 2005 to 2009. These EFOR values are utilized in the 2010 AOS analysis, and are based on a combination of historical data, experience, and operational judgment. Table 3 also illustrates the EFOR projections for the Independent Power Producers used in the 2010 AOS analysis. The EFOR assumption generally reflects the 5-year average of the specific unit, or group of similar units. EFOR projections are uncertain, however, and actual

4 Acquired 2009 end-of-year impacts at the net-to-system level.

5 The values in Table 2 reflect, for planning purposes, the cumulative amount of load available for interruption at the net-to-system level. The CIDLC program has a limit of 300 cumulative hours that each contracted load can be interrupted in a year, which is taken into account in the loss of load probability calculations reflected in Table 8.

experience may differ from the projections made. Refer to Appendix 2 for additional information on EFOR.

Table 3: Historical and Forward-looking EFOR

						AOS EFOR Rates (Base Case)			
	2005	**2006**	**2007**	**2008**	**2009**	**2010** Forward Looking	**2009**	**2008**	**2007**
Honolulu 8	1.7%	3.1%	2.0%	17.8%	4.1%	10.9%	12.3%	11.7%	11.3%
Honolulu 9	12.0%	25.8%	25.3%	11.1%	6.6%	10.9%	12.3%	11.7%	11.3%
Waiau 3	42.2%	24.0%	19.6%	23.3%	1.4%	22.1%	26.7%	27.7%	11.3%
Waiau 4	5.0%	27.2%	7.9%	13.7%	9.6%	12.7%	13.4%	13.1%	11.3%
Waiau 5	1.0%	1.7%	4.3%	11.7%	4.1%	4.7%	4.4%	3.7%	2.6%
Waiau 6	2.6%	9.2%	11.2%	1.2%	0.0%	4.7%	4.4%	3.7%	2.6%
Waiau 7	0.6%	1.1%	4.2%	20.7%	2.4%	6.3%	6.5%	6.3%	6.6%
Waiau 8	23.5%	18.5%	3.9%	2.9%	1.9%	6.3%	6.5%	6.3%	6.6%
Waiau 9	69.2%	14.5%	11.7%	24.3%	6.2%	11.4%	12.0%	11.5%	12.7%
Waiau 10	7.4%	26.2%	7.6%	14.3%	1.6%	11.4%	12.0%	11.5%	12.7%
Kahe 1	5.4%	1.6%	0.4%	4.6%	2.3%	3.4%	3.0%	3.0%	3.2%
Kahe 2	2.0%	0.9%	7.5%	1.6%	7.6%	3.4%	3.0%	3.0%	3.2%
Kahe 3	8.3%	2.1%	7.7%	0.7%	3.8%	6.3%	6.5%	6.3%	6.6%
Kahe 4	4.9%	1.4%	6.1%	4.7%	7.0%	6.3%	6.5%	6.3%	6.6%
Kahe 5	3.1%	3.1%	2.5%	0.3%	9.0%	3.6%	3.3%	4.1%	4.6%
Kahe 6	5.9%	2.8%	0.4%	2.1%	3.3%	2.9%	2.9%	3.1%	4.0%
CIP CT-1					22.0%	5.0%			
HECO	**9.3%**	**5.3%**	**5.1%**	**5.6%**	**5.0%**	**5.5%**	**5.9%**	**6.1%**	**5.4%**

H-Power	10.0%	10.0%	10.0%	10.0%
Kalaeloa	1.5%	1.5%	1.5%	1.5%
AES	1.5%	1.5%	1.5%	1.0%

4.4. Additions of Firm Generating Capacity

The Campbell Industrial Park CT-1, a 113 MW net simple-cycle combustion turbine, was placed in service on August 3, 2009. The 2010 AOS analysis reflects CIP CT-1 as available for the entire year in 2010 and all years thereafter.

The State of Hawaii Department of Transportation, Airports Division ("DOT"), plans to install an approximately 8 MW distributed standby generation ("Airport DSG") in 2011. Under an agreement between Hawaiian Electric and DOT, Hawaiian Electric will be able to use the Airport DSG to serve system needs under certain conditions. Nearly all of the generation provided by the Airport DSG will be dispatchable by Hawaiian Electric under the conditions given in the agreement. However, the Airport DSG is not utility-owned capacity and Hawaiian Electric will not have exclusive dispatch rights under all system conditions. For the purposes of the 2010 AOS analysis, the 8 MW capacity is not included.

The existing 29.5 MW of temporary Hawaiian Electric-sited distributed generation ("DG") units, which were installed as measures to mitigate the potential effects of the reserve capacity shortfall, are assumed to continue in service. This is because (1) the units will continue to serve as a mitigation measure for potential reserve capacity shortfalls and (2) they are capable of providing quick-start capability, which will increase in system operational and reliability value as the penetration of intermittent and variable generation, such as from wind and photovoltaic resources, is expected to grow on Oahu in the near term. Hawaiian Electric will continue to evaluate the DG units' contribution to system reliability as well as their costs, and may reassess their status in the future.

On December 15, 2009 in Docket No. 2009-0291 (Hawaiian Electric's petition for a declaratory order regarding the exemption of the proposed H-Power project from the Framework for Competitive Bidding ("Framework"), the Commission issued an Order stating that the project is exempt from the Framework. Hawaiian Electric is currently in discussions with the City & County of Honolulu to purchase up to an additional 27 MW of power from an expansion of the existing waste-to-energy facility.

While the project is projected to become operational in 2012, for the purposes of the 2010 AOS analysis, given the uncertainty in the timing of when the proposed project will be completed and placed in service, the additional capacity from this project was not included in the analysis.

In addition to these firm generation power projects, Hawaiian Electric also anticipates adding as-available energy projects to the Hawaiian Electric system. For example, on August 5, 2009, Hawaiian Electric submitted an application for Commission approval of a power purchase agreement ("PPA") with Kahuku Wind Power, LLC for up to 30 MW of as-available wind energy. Hawaiian Electric has also negotiated a PPA with Honua Power, LLC, to purchase approximately 6.6 MW of as-available biomass energy, and submitted an application for Commission approval of a power purchase contract on January 19, 2010.

Because these as-available generating units cannot be dispatched to provide a specified level of power to serve the peak load, power from these units are not included in the planning criteria and reliability guideline calculations.

4.5. Reductions of Firm Generating Capacity

For the purposes of the 2010 AOS analysis, no firm generating capacity is removed from service.

5. Scenario Analysis

5.1 Description of Scenarios

Forecasts of the inputs to the analysis are subject to uncertainties. Therefore, a range of forecasts was considered in the analysis. Descriptions of the various planning scenarios are provided below:

- Two-month outage of a 90 MW unit (in addition to the EFORs assumed);
- Higher load forecast (60 MW increase in peak load);
- Reduced RDLC program impacts; and
- Increased stringency of Hawaiian Electric's generating system reliability guideline from 4.5 years per day to 10 years per day.

Hawaiian Electric performed a scenario analysis assuming a higher EFOR, based on the extended-duration outage of a generating unit, to analyze the impacts of such an event. Hawaiian Electric used either Kahe 3 or Kahe 4 (90 MW) as the proxy unit, simulating an additional period of unavailability lasting two months, beginning in June of each year. These units were selected because they are neither the largest nor smallest MW units on the system, but something in between that effectively represents many units on the system. Similarly, the June through July timeframe was selected because it is a period of "middle-of-the-road" system demand. This period is neither the worst time for a unit to be unavailable, nor the best.

The higher load scenario used the assumption that the system peaks are higher by 60 MW. Such a scenario is possible, for example if, (1) customer acceptance and/or awareness is less than expected in the case of the load management DSM programs, or energy efficiency DSM programs; (2) electricity use is higher than that projected by the Hawaiian Electric sales and peak forecast due to a recovering economy; or (3) a combination of these or other factors occur in the future. A 60 MW higher peak load is roughly equivalent to one standard deviation over a 20 year period of historical peaks (peak 1989-2008). Table 4 summarizes the higher load scenario.

Table 4: Higher Load Scenario

Year	2010 AOS Dec 2009 S&P Forecast (MW)	60 MW higher Dec2009 S&P Forecast (MW)	Difference (MW)
2010	1,238	1,298	60
2011	1,245	1,305	60
2012	1,259	1,319	60
2013	1,261	1,321	60
2014	1,279	1,339	60

The reduced RDLC scenario uses the assumption that the actual impact of load reduction gained from the residential water heater load control program may not be coincident with the system peak. For example, while the residential water heater program had approximately 35,000 participants at the end of 2009, a portion of the participants may not have the full water heating load available to Hawaiian Electric at the time the load reduction is initiated due to factors, such as timers that operate their water heaters. For the purposes of this scenario, a 50% reduction in the water heater impacts was analyzed. Table 5 summarizes the 2009 year-end RDLC impacts for water heater and air conditioning impacts, and the alternate scenario analysis

Table 5: Reduced RDLC Scenario

Year	Base Case RDLC (MW)			Reduced RDLC Scenario (MW)	
	Air-Conditioning Load	Base Water Heater Load	Total RDLC	Reduced Water Heater Load	Reduced RDLC Scenario
2010	4	22	26	11	15
2011	4	22	26	11	15
2012	4	22	26	11	15
2013	4	22	26	11	15
2014	4	22	26	11	15

Another potential means to address the ever increasing planning uncertainty and complexity is to revise the capacity planning guideline. As explained in Section 3.2, Hawaiian Electric currently uses a reliability guideline threshold of 4.5 years per day. If the existing Loss of Load Probability of 4.5 years per day does not provide an adequate cushion to respond to quickly-changing parameters, such as changes in peak demand and individual unit availability factors, many of which may change rapidly from year to year, then the utility could plan for a higher reliability standard similar to that many mainland utilities. Such an approach would not eliminate quickly-changing parameters, but it would add a measure of conservatism in recognition that the uncertainties undoubtedly exist.

Hawaiian Electric performed a high-level evaluation using a more stringent reliability guideline of 10 years per day. The purpose of this analysis was to determine the amount of firm capacity that would be required to meet this higher reliability guideline

5.2. Results of Analysis

Table 6 shows that the Rule 1 and Rule 2 criteria are satisfied for the Reference Scenario for each year through 2014 under a reference set of assumptions including, but not limited to: (1) continued residential and commercial load management impacts at the levels described in Table 2; (2) continued acquisition of energy efficiency DSM programs but by a third party instead of by Hawaiian Electric; (3) the inclusion of 29.5 MW of temporary, Hawaiian Electric-sited distributed generation; and (4) the addition of the CIP CT-1 generating unit. However, as previously explained, Rule 1 and Rule 2 results are deterministic, and do not incorporate unit specific EFOR rates in their calculation.

Table 6: Rule 1 and Rule 2 Analysis

Year	Rule 1 Results (MW)	Rule 2 Results (MW)
2010	224	184
2011	183	143
2012	219	179
2013	180	140
2014	156	116

The LOLP for the Reference and Planning Scenarios were calculated using a production simulation model for each year through 2014 under reference and variable sets of assumptions described in Section 4.

For the years 2010 to 2014, the generating system's 4.5 years per day reliability guideline is projected to be met in the reference scenario, but will be less than the 4.5 years per day reliability guideline in 2011, 2013 and 2014 in the extended outage scenario, and for all years 2010-2014 in the higher load scenario. The reduced RDLC scenario meets the reliability guideline for the years 2010 to 2013. Further, under the higher generating system reliability scenario of 10 years per day, the guideline will not be met with the reference scenario assumptions. Table 7 shows the results of the reliability analysis.

Table 7: Generation System Reliability Guideline (years/day)

Generation System Reliability (years/day)					
Year	2010 AOS Reference	Two-Month 90 MW Outage	Higher Load (Add 60 MW)	50% Reduced RDLC	2010 AOS Reference (10 yr/day)
2010	9.7	5.6	2.5	7.6	9.7
2011	7.1	3.8	1.9	5.6	7.1
2012	8.8	6.4	2.4	7.0	8.8
2013	5.9	3.9	1.6	4.7	5.9
2014	5.1	2.5	1.4	4.1	5.1

Table 8 shows the reserve capacity surpluses or shortfalls corresponding to the calculated reliability shown in Table 7. Reserve capacity shortfall is the approximate amount of additional firm capacity needed to restore the generating system LOLP to be greater than the 4.5 years per day reliability guideline. For example, in the Higher Load *scenario for 2010, the number -30 would indicate that 30 MW of firm generating capacity* would have to be added in order for the expectation of not being able to satisfy demand due to insufficient generation occurs no more than once every 4.5 years. A positive number indicates the amount of capacity over and above that amount needed to satisfy the 4.5 years per day reliability guideline. A negative number indicates the amount of capacity below the amount needed to satisfy the 4.5 years per day reliability guideline.

Table 8: Reserve Capacity Shortfall for Reference and Planning Scenarios (MW)

		Alternate Scenarios			
Year	Reference Scenario	Two-Month 90 MW Outage	Higher Load (Add 60 MW)	Reduced Water Heater RDLC	10 yrs/day reliability scenario
2010	30	10	-30	20	-10
2011	20	-10	-40	0	-20
2012	30	10	-30	20	-10
2013	10	-10	-50	0	-30
2014	0	-30	-60	-10	-40

(Note: Negative values indicate a shortfall of generating capacity; positive values indicate a surplus of generating capacity)

The analysis shows that the reserve capacity shortfall is sensitive to the load forecast. In the case of the Higher Load Scenario, a nominal 60 MW increase in the forecasted load resulted in a 60 MW change to the results, indicating a reserve capacity shortfall in all years analyzed in contrast to no reserve capacity shortfall projected in the Reference Scenario. Expectations regarding future loads can change quickly, and Hawaiian Electric may not be able to respond quickly to increases in demand. This illustrates the importance of using scenario analysis as a planning tool.

The analysis also shows that a reserve capacity shortfall may occur in 2015 in the Reference Scenario and as early as 2010 in a high load scenario. Additional demand-side resources, including additional load management, can benefit generation system reliability over this short-term horizon.

The Two-Month 90 MW Outage Scenario results in a reduction in reserve capacity from a 30 MW shortfall (i.e., -30 MW) to a 10 MW surplus in the 2010 to 2014 timeframe. The moderate change in capacity is a function of when in the year the 90 MW is unavailable. Hawaiian Electric is not likely to have control over when an extended-duration outage of a Hawaiian Electric or IPP unit occurs, and therefore, the analytical results of this scenario should not be misinterpreted as the "typical" impact on system reliability.

Table 8 further projects that for the years 2010 to 2014, approximately 10 MW to 40 MW of firm capacity must be added to the Hawaiian Electric system to achieve a higher reliability guideline of 10 years/day. The approximately 40 MW difference between the 4.5 years/day Reference Scenario and the 10 years/day Scenario to achieve higher levels of reliability is a non-linear relationship between MW capacity added and improvement in LOLP.

5.3. Other Planning Considerations

The risks associated with action and inaction are not symmetrical. While Hawaiian Electric has the ability to delay the execution of its resource plans when circumstances, such as an economic slump resulting in reduced load growth, lead to a reduction in urgency, it has very limited ability or no ability to accelerate the addition of significant generation resources if unanticipated changes in key drivers require that firm capacity be added sooner than anticipated. This is because Hawaiian Electric has little control over the rate at which major equipment can be manufactured and the speed of the permitting and regulatory review process. This asymmetrical risk profile is considered when determining the date at which new capacity should be added for any of the reasons cited on Section 4 above.

6. Conclusion

Under the Reference Scenario, Hawaiian Electric's generation capacity for the next five years (2010-2014) will be sufficient to meet reasonably expected demands for service and provide reasonable reserves for emergencies.

The scenario analysis indicates that in 2010, Hawaiian Electric may experience anywhere from a 30 MW reserve capacity shortfall under the higher load scenario to a 30 MW reserve capacity surplus in the reference scenario. By 2014, Hawaiian Electric may experience anywhere from a 60 MW to zero reserve capacity shortfall under various scenarios. The range of potential reserve capacity shortfalls can be addressed through the acquisition of additional energy efficiency and load management demand-side resources over the near-term.

Hawaiian Electric will continue its portfolio approach to meet its obligation to serve, which includes demand-side programs, the use of temporary firm capacity distributed generation as a mitigation measure, the use of firm capacity distributed generation (with more permanent design features) as a long-term resource, and the pursuit of firm capacity renewable central-station supply side options. Hawaiian Electric also recognizes that the environment for resource planning has increased in complexity and uncertainty. Hawaiian Electric must therefore be proactive, anticipating the what-ifs, and cannot bank on the Reference Scenario occurring.

Very truly yours,

Darcy L. Endo-Omoto
Vice President
Government & Community Affairs

Attachments

c: Division of Consumer Advocacy (with Attachments)

Table A1:
Projected Reserve Margins with and without Future DSM

Year	System Capability at Annual Peak Load (net kW) [A] (II)	Without Future DSM(I)			With Future DSM(I)		
		System Peak (net kW) [B] (III)	Interruptible Load (net kW) [C] (IV)	Reserve Margin (%) [A-(B-C)] (B-C)	System Peak (net kW) [D] (V)	Interruptible Load (net kW) [E] (VI)	Reserve Margin (%) [A-(D-E)] (D-E)
2009	1,785,100	1,237,000	54,000	51%	1,237,000	54,000	51%
2010	1,785,100	1,257,500	54,000	48%	1,238,000	54,000	51%
2011	1,785,100	1,270,700	54,000	47%	1,245,000	54,000	50%
2012	1,785,100	1,291,100	54,000	44%	1,259,000	54,000	48%
2013	1,785,100	1,300,100	54,000	43%	1,261,000	54,000	48%
2014	1,785,100	1,325,100	54,000	40%	1,279,000	54,000	46%

Notes:

I. Acquired DSM
- Implementation of full-scale DSM programs began in the second half of 1996 following Commission approval of the programs. The forecasted system peak values for the years 2010-2014 include the estimated peak reduction benefits acquired up to June 2009.

II. System Capability includes:
- Hawaiian Electric central station units at total normal capability with CT-1 and temporary Hawaiian Electric-sited distributed generation is 1,351,100 kW-net or 1,847,000 kW-gross.
- Temporary, Hawaiian Electric-sited distributed generating units with a total capability of 29,500 kW-net.
- Firm power purchase contracts with a combined net total of 434,000 kW from Kalaeloa (208,000 kW), AES Hawaii (180,000 kW), and H-POWER (46,000 kW).
- When the system capability at the time of the system peak differs from the year-end system capability, an applicable note will indicate the year-end system capability.

III. System Peak (Without Future Peak Reduction Benefits of DSM Programs):
- The 2010-2014 annual forecasted system peaks are based on Hawaiian Electric's December 2009 Sales and Peak Forecast.

The peak for 2010-2014 includes approximately 25,000 kW of stand-by load.

- The Hawaiian Electric annual forecasted system peak is expected to occur in the month of October.

IV. Interruptible Load (Without Future Peak Reduction Benefits of DSM Programs):

- Interruptible Load impacts are at the net-to system level, (based on a T&D loss factor of 4.93%) and are approximate end of year impacts.
- By the end of 2009, Hawaiian Electric had acquired approximately 54,000 kW of Load Management DSM peak reduction benefits from the RDLC and CIDLC Programs.
- Interruptible Load includes approximately 4,000 kW of the peak reduction benefits from Rider I customer contracts.

V. System Peaks (With Future Peak Reduction Benefits of DSM Programs)

- The 2010-2014 annual forecasted system peaks are based on Hawaiian Electric's December 2009 Sales and Peak Forecast.
- The forecasted System Peaks for 2010-2014 include the estimated peak reduction benefits of third-party energy efficiency DSM programs

The peak for 2009-2014 includes approximately 25,000 kW of stand-by load.

- The Hawaiian Electric annual forecasted system peak is expected to occur in the month of October.

VI. Interruptible Load (With Future Peak Reduction Benefits of DSM Programs):

- Interruptible Load impacts are at the net-to system level, (based on a T&D loss factor of 4.93%) and are approximate end of year impacts.

Hawaiian Electric Equivalent Forced Outage Rate (EFOR) Discussion

It is extremely difficult to predict unit-specific EFOR rates, as indicated by the variation in historical data. Nonetheless, for planning purposes it is necessary to estimate forward-looking EFOR rates. This is accomplished using a blend of historical data, experience, and judgment. Accordingly, the estimated EFOR rates used in the 2010 AOS analysis and the rationale for them are described in the following paragraphs.

1. Honolulu Units 8 and 9

   In the 2009 AOS, the forward looking EFOR of 12.3% included the actual average of 5 years for both H8 and H9. The actual EFOR for 2009 for Honolulu Units 8 & 9 were 4.1% and 6.6%, respectively, and averaged 5.4% for the two units. For the 2010 AOS analysis, it was decided to continue to utilize the average of the actual EFOR for both units for the past 5 years. This approach recognizes that these units will be dispatched and operated similarly in 2010 as they were in recent years. As a result, an EFOR of 10.9%, 1.4% lower than that utilized for the 2009 AOS analysis, is recommended for the 2010 AOS forward looking EFOR for both Honolulu Units 8 and 9.

2. Waiau Units 3 and 4

   In the 2009 AOS, the forward looking EFOR for Waiau Unit 3 was 26.7%. The actual EFOR for 2009 for Waiau Unit 3 was 1.4%. The actual EFOR was significantly lower than the forecast. For the 2010 AOS analysis, it was decided to continue to use the average of the actual EFOR rates for the past 5 years. This approach recognizes that Waiau Unit 3 will be dispatched and operated similarly in 2010 as it was in recent years. Thus, for Waiau Unit 3, an EFOR of 22.1%, 4.6% lower than that utilized for the 2009 AOS analysis, is recommended for the 2010 AOS forward looking EFOR.

   In the 2009 AOS, the forward looking EFOR for Waiau Unit 4 was 13.4%. The actual EFOR for 2009 for Waiau Unit 4 was 9.6%. On average, the reliability compared well with the forecast. For the 2010 AOS analysis, it was decided to continue and utilize the average of the actual EFOR of the unit for the recent 5 years. Thus, for Waiau Unit 4, an EFOR of 12.7%, 0.7% lower than that utilized for the 2009 AOS analysis, is recommended for the 2010 AOS forward looking EFOR.

3. Waiau Units 5 and 6

In the 2009 AOS, the forward looking EFORs for Waiau Units 5 and 6 were 4.4% based on the average actual EFORs for both units for the recent 5 years. The actual EFOR for 2009 for Waiau Units 5 and 6 were 4.1% and 0.0%, respectively. Waiau Unit 5 compared well with the forecast, while Waiau Unit 6 was significantly lower than forecast. For the 2010 AOS analysis, it was decided to continue to use the average of the actual EFOR rates for the past 5 years. This approach also recognizes that the units will be dispatched and operated similarly in 2010 as they were in recent years. As a result, an EFOR of 4.7%, 0.3% higher than that utilized for the 2009 AOS analysis is recommended for the 2010 AOS forward looking EFOR for both Waiau 5 and 6

4. Waiau Unit 7, Waiau Unit 8, Kahe Unit 3, and Kahe Unit 4

These four units are of similar size, design, and vintage, and are dispatched as baseloaded units with similar duty cycles. Accordingly, in the 2009 AOS, the forward looking EFOR rate of 6.5% was used for these four units. The actual EFOR for 2009 for Waiau 7, Waiau 8, Kahe 3, and Kahe 4 were 2.4%, 1.9%, 3.8%, 7.0%, respectively, with an average of 3.8%. For the 2010 AOS analysis, it was decided to continue to use the average of the actual EFOR rates for the four units for the past 5 years. This approach also recognizes that these units will be dispatched and operated similarly in 2010 as they were in recent years. As a result, an EFOR of 6.3%, 0.2% lower than that utilized for the 2009 AOS analysis is recommended for the 2010 AOS forward looking EFOR for Waiau Units 7 and 8, and Kahe Units 3 and 4.

5. Waiau Units 9 and 10

In the 2009 AOS, the forward looking EFORs for Waiau Units 9 and 10 were 12.0% based on the average of the actual EFORs for both units for the recent 5 years. The actual EFOR in 2009 for Waiau Units 9 and 10 were 6.2% and 1.6%, respectively, and averaged 3.9% for the two units. The reliability for both units were significantly better than forecast. For the 2010 AOS analysis, it was decided to continue to use the average of the actual EFOR rates for both units for the past 5 years. This approach also recognizes that these units will be dispatched and operated similarly in 2010 as they were in recent years. As a result, an EFOR of 11.4%, 1.4% lower than that utilized for the 2009 AOS analysis is recommended for the 2010 AOS forward looking EFOR for Waiau 9 and 10.

6. Kahe Units 1 and 2

In the 2009 AOS, the forward looking EFORs for Kahe Units 1 and 2 were 3.0% based on the average of the actual EFORs for both units for the recent 5 years. The actual EFOR in 2009 for Kahe Unit 1 and 2 were 2.3% and 7.6%, respectively, and averaged 5.0% for both units. For the 2010 AOS analysis, it was decided to continue to use the average of the actual EFOR rates for both units for the past 5 years. This approach also recognizes that these units will be dispatched and operated similarly in 2010 as they were in recent years. As a result, an EFOR of 3.4%, 0.4% higher than that utilized for the 2009 AOS analysis is recommended for the 2010 AOS forward looking EFOR for Kahe 1 and 2.

7. Kahe Unit 5

In the 2009 AOS, the forward looking EFOR for Kahe Unit 5 was 3.3% based on the average of the actual EFOR for the recent 5 years. The actual EFOR of 9.0% was higher than the forecast. For the 2010 AOS analysis, it was decided to continue to use the average of the actual EFOR rate for the past 5 years. This approach recognizes that this unit will be dispatched and operated similarly in 2010 as it was in recent years. As a result, an EFOR of 3.6%, 0.3% higher than that utilized for the 2009 AOS analysis is recommended for the 2010 AOS forward looking EFOR for Kahe 5.

8. Kahe Unit 6

In the 2009 AOS, the forward looking EFOR for Kahe Unit 6 was 2.9% based on the average of Kahe Unit 6 actual EFOR for the recent 5 years. The actual EFOR for 2009 for Kahe Unit 6 was 3.3%, and compared fairly well with the forecast. For the 2010 AOS analysis, it was decided to continue to use the average of the actual EFOR rate for the past 5 years. This approach also recognizes that Kahe Unit 6 will be dispatched and operated similarly in 2010 as it was in recent years. As a result, an EFOR of 2.9%, no change from that utilized for the 2009 analysis is recommended for the 2010 AOS forward looking EFOR for Kahe Unit 6.