Hawaiian Electric Company • PO Box 2750 • Honolulu, HI 96840

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Patsy H. Nanbu
Vice President
Regulatory Affairs

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PUBLIC UTILITIES COMMISSION

The Honorable Chair and Members of the Hawaii
Public Utilities Commission
465 South King Street
Kekuanaoa Building, Room 103
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.*

2013 Adequacy of Supply Report Summary

- Hawaiian Electric currently has sufficient firm capacity to meet projected peak demand in 2013, based on the Company's August 2012 Sales and Peak Forecast.

[1] Hawaiian Electric's Adequacy of Supply ("AOS") Report is due within 30 days after the end of the year. On January 25, 2013, Hawaiian Electric requested an extension of time, to no later than March 28, 2013, to file its AOS Report due to Hawaiian Electric's heavy workload related to other proceedings. The Commission granted Hawaiian Electric's extension by letter dated March 11, 2013.

- The adjusted peak load experienced on Oahu in 2012 was 1,151MW net, and was served by Hawaiian Electric's total capability of 1,756MW net, including firm power purchases. This represents a reserve margin of approximately 58% over the 2012 adjusted system net peak.

- Peak load is projected to grow at a compounded average growth rate of 1.35% through 2018 and 0.9% through 2023. Current peak projections are significantly lower than they were in Hawaiian Electric's 2012 AOS, particularly in the near term.

- Solar generation additions have reduced the daytime load on the system. As solar capacity continues to grow year over year daytime loads are projected to be reduced, and all else being equal, the average daily load profile is expected to have a more pronounced evening peak.

- Starting in 2013, Hawaiian Electric has revised its metric for forced outage rates from Equivalent Forced Outage Rate ("EFOR") to Forced Outage Rate Demand ("EFORd"), to better represent the availability of each generating unit based on it operating mode (i.e., base loaded, cycling, and peaking).

- Waiau Units 3 and 4 (with a combined rating of 92.6 MW-net), and Honolulu Units 8 and 9 (with a combined rating of 107.3 MW-net) are candidates for change in operational status, such as deactivation or decommissioning. The 2013 AOS reference case assumes the unit pairs will be removed from service at the end of 2017 and 2019.

- Under the Reference Scenario, Hawaiian Electric's generation capacity for the next seven years (2013-2019) will be sufficient to meet reasonably expected demands for service and provide reasonable reserves for emergencies.

- Depending on system conditions, Hawaiian Electric may experience anywhere from a 40 MW to a 130 MW reserve capacity shortfall by 2020.

- Hawaiian Electric is continuing to pursue the addition of approximately 50 MW of utility owned and operated, firm, renewable, dispatchable, generation on federal lands, for the purpose of ensuring that the Army's critical national security and first responder missions can be carried on. It is estimated that the security project could be in service in the 2017 timeframe, which would change the timing and amount of a reserve capacity shortfall.

- Hawaiian Electric anticipates that it will need additional firm capacity beginning in the 2019 timeframe in anticipation of the potential change in operational status of generating units at the end of 2017 and 2019. Hawaiian Electric will seek to acquire the additional firm capacity through a competitive bidding process, the scope of which will be defined in the on-going Integrated Resource Planning ("IRP") process.

1. Peak Demand and System Capability in 2012

Hawaiian Electric's 2012 system peak occurred on Tuesday, December 4, 2012, and was 1,169,000 kW-gross or 1,141,000 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 cogenerating units not been operating, the 2012 system peak would have been approximately 1,179,000 kW-gross or 1,151,000 kW-net.

Hawaiian Electric's 2012 total generating capability of 1,755,600 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.[3]

Oahu had a reserve margin of approximately 58% over the 2012 adjusted system net peak.[4]

At times during 2012, Hawaiian Electric received energy from six as-available energy producers (i.e., Chevron, Tesoro, Kahuku Wind Power, Kapolei Sustainable Energy Park, Kawailoa Wind, Kalaeloa Solar 2). 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 ten years, 2013-2022 based on Hawaiian Electric's August 2012 Sales and Peak Forecast, and includes estimated energy efficiency impacts and forecasted load management impacts.

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[2] At the time of the peak, certain units at Tesoro, Chevron, and Pearl Harbor were generating about 10,000 kW of power for use at their sites.

[3] During the 2012 calendar year, H-POWER was operated at a contracted amount of 46 MW. On May 25, 2012 in Docket No. 2012-0129 Hawaiian Electric submitted an application for approval of an Amended and Restated Power Purchase Agreement ("PPA") 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. On November 15, 2012, Hawaiian Electric filed Amendment No. 1 to the PPA. On January 17, 2013 in Decision and Order ("D&O") 30950 the Commission approved the PPA as Amended.

[4] The reserve margin calculation takes into account the approximately 38 MW of interruptible load at system peak served by Hawaiian Electric.

3. Criteria to Evaluate 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 ("DSM") programs, (b) net energy metering, and (c) customer-sited photovoltaic ("PV") installations; [§4.1]
- peak reduction benefits of load control programs; [§4.2]
- Equivalent Forced Outage Rate Demand ("EFORd") on the generating units; [§4.3]
- planned maintenance schedules for the generating units on the system; [§4.4]
- additions of firm generating capacity; [§4.5] and
- reductions of firm generating capacity. [§4.6]

The above mentioned forecasts are similar to those used in Hawaiian Electric's 2012 AOS Report, with the exception of EFORd, as described in Section 4.3. 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 was 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 EFORd's 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 the total capacity of the system in MW, 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 could be lost from service during the peak.

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

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, Senior Vice President of Operations, 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 planning uncertainty and complexity would be to revise the capacity planning guideline. 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 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.

The typical reliability standard on the mainland is 10 years per day, which is more stringent than the 6 years per day suggested by the Consumer Advocate and the 4.5 years per day in Hawaiian Electric's reliability guideline. A scenario analysis of the reserve capacity shortfall based on a higher reliability guideline threshold of 10 years per day is included in Section 5. The results of the analysis show the additional amount of firm capacity that would be needed on the Oahu grid to meet a higher, 10 years per day, reliability standard based on the assumptions provided herein.

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

4. Key Inputs to the 2013 AOS Analysis

4.1. August 2012 Sales and Peak Forecast

Hawaiian Electric developed a short-term sales and peak forecast in May 2012 ("May 2012 forecast"), which was subsequently adopted by the Company for future planning purposes. In August 2012, Hawaiian Electric updated its sales forecast due to current projections at that time. Hawaiian Electric's August 2012 sales and peak forecast was used for the purposes of this analysis.

Figure 1 illustrates Hawaiian Electric's historical system peaks and compares them to the forecast used in the 2012 and 2013 AOS analyses. The analyses contained in the 2012 AOS were based on a May 2011 sales and peak forecast.

Figure 1: Recorded Peaks and Future Year Projections

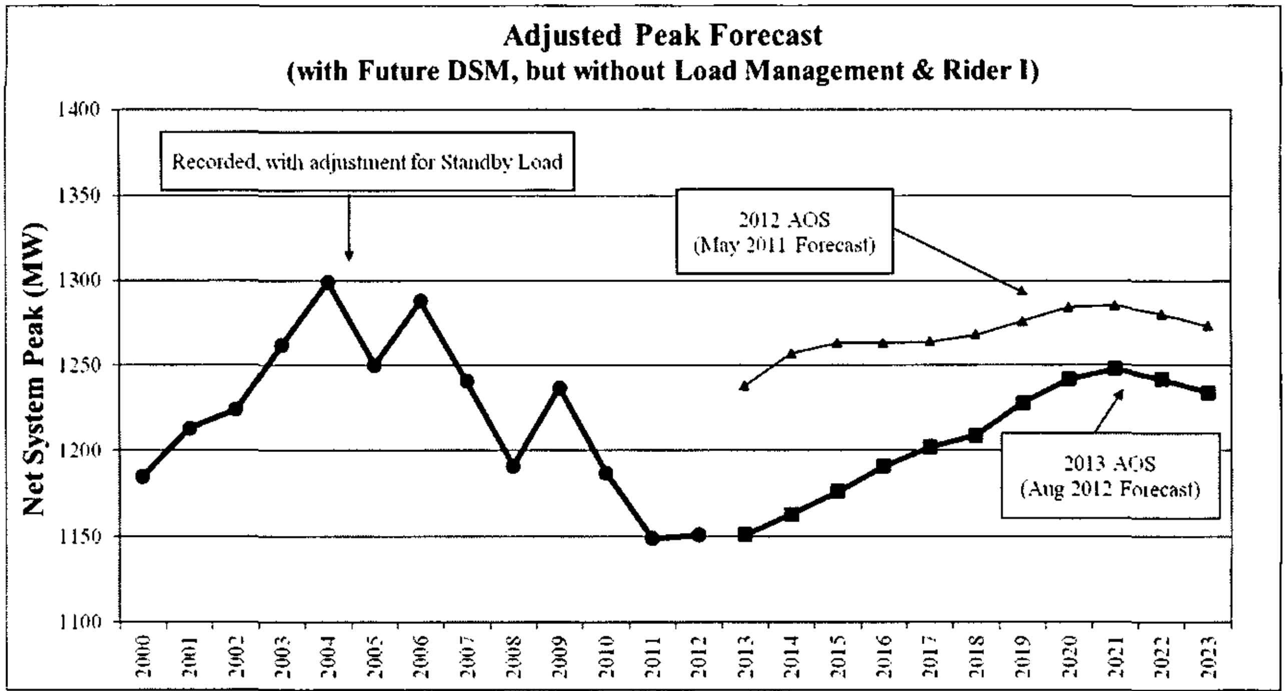

Table 2 below provides the recorded peaks from 2000 and compares the forecasts used in the 2012 AOS and this 2013 AOS. The comparison between forecasts indicate the degree to which key planning assumptions such as the peak forecast can change significantly in one year.

For both the recorded and forecast data, figures reflect an upward (stand-by) adjustment to account for the potential need to serve certain large customer loads (i.e., Chevron, Tesoro and Pearl Harbor) that are frequently served by their own internal generation. Figure 1 includes the peak reduction benefits of energy efficiency programs and naturally occurring conservation. The forecast also includes the impact of customer-sited photovoltaic ("PV") and other renewable generation system installations through the Net Energy Metering ("NEM") program, Standard Interconnection Agreements ("SIA"), and Feed-In Tariffs ("FIT") in the derivation of sales. Table 3 shows the projected MW capacities for NEM, FIT and SIA installations, and the corresponding Annual (Ramped) MWh Reductions that are assumed to reduce sales and day peaks. As solar capacity continues to grow year over year, daytime loads are projected to be reduced, and all else being equal, the average daily load profile is expected to have a more pronounced evening peak.

Table 2: 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	2012 AOS May 2011 S&P	2013 AOS Aug2012 S&P	Difference 2013-2012 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			
2010	1162	1187			
2011	1141	1149			
2012	1141	1151			
2013			1,238	1,151	-87
2014			1,257	1,163	-94
2015			1,263	1,176	-87
2016			1,263	1,191	-72
2017			1,264	1,202	-62
2018			1,268	1,209	-59
2019			1,276	1,228	-48
2020			1,284	1,242	-42
2021			1,285	1,248	-37
2022			1,280	1,242	-38
2023			1,273	1,234	-39

Table 3: SIA, NEM & FIT Projections
August 2012 Sales Forecast

Year	Forecasted MW Installations (I)		Annual (Ramped) MWh Reduction (II)
	MW	Cumulative	
2013	90	140	99,304
2014	70	210	185,367
2015	81	291	274,374
2016	67	358	380,960
2017	68	426	469,229
2018	63	489	557,622
2019	63	552	645,289
2020	63	615	732,956
2021	63	678	820,623
2022	54	731	902,062
2023	47	778	971,478

Notes:

I. Impacts to the peak demand from systems installed under SIA, NEM and FIT are assumed to affect the day peak only.
II. MWh reduction from the systems under FIT are associated with the output from the system that offsets a customer's load and not energy sold to Hawaiian Electric.

4.2. Projected Peak Reduction Benefits of Load Control Programs

Hawaiian Electric continues to administer the Commercial & Industrial Direct Load Control ("CIDLC") and Residential Direct Load Control ("RDLC") programs (collectively referred to as the "EnergyScout Programs"). In April and May 2012, respectively, Hawaiian Electric submitted application requests to the Commission for the proposed expansion of the RDLC and CIDLC programs beginning in 2013.[5] On September 28, 2012 in Order Nos. 30662 and 30663, the Commission approved continuation and extension of the RDLC and CIDLC programs through 2013, or until a

5 Refer to *Application for Approval of Expansion of the Residential Direct Load Control Program and Recovery of Program Costs*, filed April 13, 2012, in Docket No. 2012-0079, and *Application for Approval of Expansion of the Commercial and Industrial Direct Load Control Program and Recover of Program Costs*, filed on May 17, 2012 in Docket No. 2012-0118.

final decision and order is issued, pending the Commission's further consideration of the Company's request for expansion of the EnergyScout Programs.[6]

Hawaiian Electric is also continuing to implement its FastDR[7] pilot program, and is anticipating implementing its proposed Commercial and Industrial Dynamic Pricing Pilot ("CIDP Pilot") Program.[8]

For the purposes of this analysis, the expansions of the EnergyScout programs, the FastDR pilot, and the CIDP Pilot are assumed to reflect the continued contribution of these programs to Hawaiian Electric's capacity planning analysis. Hawaiian Electric estimates it had approximately 18 MW (net-to-system generation) of controlled load under its CIDLC program, and approximately 16 MW (net-to-system level) of controlled load under its RDLC program in 2012. Table 4 shows the forecast of the peak reduction benefits from its existing and future load management programs[9] predicated upon Commission approval of the expansion of these programs.

Table 4: Projected Commercial, Residential and Rider I Impacts (MW)[10]

Year	Residential	Commercial	Rider I	Total
2013	16	25	4	45
2014	19	26	4	49
2015	23	30	4	57
2016	27	32	4	64
2017	31	35	4	69
2018	33	37	4	74
2019	39	40	4	83
2020	45	42	4	91
2021	51	45	4	100
2022	56	48	4	109
2023	62	51	4	117

6 See Order No. 30662, issued on September 28, 2012, in Docket No. 2012-0079 and Order No. 30663, issued on September 28, 2012 in Docket No. 2012-0118.

7 See *Decision and Order Approving a Fast Demand Response Pilot Program and Recovery of Program Costs*, filed on November 9, 2011, in Docket No. 2010-0165.

8 See *Request for Approval of a Commercial and Industrial Dynamic Pricing Pilot Program and Recovery of Program Costs*, filed on December 29, 2011, in Docket No. 2011-0392.

9 Forecasted impacts available at system peak at the net-to-system level.

10 The values in Table 4 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, and the CIDP Pilot program has a limit of 100 hours per year, 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 10.

4.3. Hawaiian Electric Generating Unit Forced, Outages

Forced outages and de-ratings reduce generating unit availability and are accounted for as explained below.

Hawaiian Electric revised its metric for forced outage rates starting in 2013. In past AOS reports, the analysis included the Hawaiian Electric units forward-looking Equivalent Forced Outage Rate ("EFOR"). In 2012, Hawaiian Electric evaluated the Forced Outage Rate Demand ("EFORd") metric, which was recently incorporated into the IEEE-762 standard,[11] and subsequently incorporated into the North American Electric Reliability Corporation's Generating Availability Data System. EFORd is intended to better represent the probability that a unit will be unable to generate at its full rated potential at the time it is actually needed, as compared to EFOR, which represents the probability that a unit will be unable to generate over a given period of service hours (with adjustments for deratings).

For units that operate all hours of the year, EFOR and EFORd would have the same value. For units that operate only a few hours of the year, such as Hawaiian Electric's combustion turbine units, EFOR and EFORd would be significantly different. The loss of load probability is affected by using EFORd, and results in effectively increasing the generating system reliability calculation.

Using EFORd instead of EFOR increases the apparent reliability of a peaking unit because the formula contains a factor that de-emphasizes the forced outage hours during off-peak periods. For example, if a peaking unit is needed to serve a four-hour peak period during a given day but it is forced out of service after operating for only two hours, the EFORd formula weights the two-hour outage during the on-peak period more heavily than the subsequent continuing outage hours in the off-peak period. EFORd also increases the apparent reliability of cycling units but to a lesser extent because cycling units operate for longer periods than peaking units. For baseload units, which operate 24 hours a day, EFOR and EFORd are nearly identical.

For example, in 2012, Hawaiian Electric's Waiau 9 combustion turbine generating unit was started and operated for a few hours of the year, with 26 actual starts for a total of 67 run hours. Given these and other statistics needed to calculate the historical metrics, EFORd for Waiau 9 in 2012 was 25.5%. In contrast, EFOR for Waiau 9 results in 2012 was 94.1%. By using the EFORd value of 25.5% instead of the EFOR value of 94.1%, the generating system reliability is calculated to be more reliable.

11 Refer to IEEE STD-762 for additional details: http://www.nerc.com/docs/pc/gadstf/ieee762tf/762-2006.pdf.

After due consideration of the merits of EFORd, Hawaiian Electric concluded it is reasonable to use EFORd in its generating system reliability calculations. The use of EFOR appears to understate the reliability of peaking and cycling units. For example, as noted in the statistics for Waiau 9 above, the unit's EFOR was 94.1% while its EFORd was 25.54%. The unit is primarily used during peak periods (5 pm to 9 pm) to provide spinning reserve. Using an EFOR of 94.1% would indicate that the unit would be able to serve this peak only 5.9% of the time, on average. This would significantly understate the availability of the unit during on-peak periods because many of the forced outage hours occur during off-peak periods when the unit is not needed. The EFORd metric provides a more meaningful statistic that better represents the probability that a generating unit will be available to produce energy when needed.

The definition of EFORd and an example of the application of the EFORd formula is provided in Appendix 2.

Other jurisdictions on the mainland have adopted EFORd in their reliability assessments. For example, PJM Interconnection,[12] Midwestern ISO,[13] ERCOT,[14] New York ISO,[15] and ISO-New England,[16] have used EFORd in recent reserve requirements and capacity planning studies.

Tables 5 and 6 provide a comparison of recorded Hawaiian Electric EFOR and EFORd data by unit for the period 2008-2012, as well as forward looking values for used for the purposes of this analysis. The forward looking EFORd values utilized in the 2013 AOS analysis are forecasted EFORd expectations for planning purposes based on a combination of historical data, experience, and operational judgment. Table 6 also illustrates the EFORd projections for the Independent Power Producers used in the 2013 AOS analysis. The EFORd assumption generally reflects the 5-year average of the specific unit, or group of similar units. EFORd and EFOR projections are not certain, however, and actual experience may differ from the projections. Refer to Appendix 3 for specific generating unit information on EFORd.

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12 Indiana, Illinois, Ohio, Pennsylvania, New Jersey, Maryland, Delaware, Virginia, West Virginia, North Carolina, Michigan, Kentucky, Tennessee, District of Columbia.

13 Montana, North Dakota, South Dakota, Minnesota, Michigan, Wisconsin, Iowa, Illinois, Indiana, Missouri, Kentucky.

14 Texas.

15 New York.

16 Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont.

Table 5: Historical and Forward-looking EFOR

	Recorded EFOR					EFOR Rates
	2008	**2009**	**2010**	**2011**	**2012**	**2013** Forward Looking
Honolulu 8	17.8%	4.1%	33.1%	7.3%	8.3%	19.4%
Honolulu 9	11.1%	6.6%	21.9%	22.6%	60.9%	19.4%
Waiau 3	23.3%	1.4%	6.7%	33.1%	9.4%	14.8%
Waiau 4	13.7%	9.6%	1.4%	24.7%	5.7%	11.0%
Waiau 5	11.7%	4.1%	2.5%	0.8%	4.0%	4.3%
Waiau 6	1.2%	0.0%	0.3%	2.8%	15.7%	4.3%
Waiau 7	20.7%	2.4%	0.1%	7.4%	0.4%	4.6%
Waiau 8	2.9%	1.9%	1.3%	11.1%	3.7%	4.6%
Waiau 9	24.3%	6.2%	0.9%	56.6%	94.1%	29.2%
Waiau 10	14.3%	1.6%	1.6%	78.1%	14.5%	29.2%
Kahe 1	4.6%	2.3%	0.7%	2.7%	0.5%	3.8%
Kahe 2	1.6%	7.6%	8.8%	2.4%	7.2%	3.8%
Kahe 3	0.7%	3.8%	3.9%	2.2%	2.5%	4.6%
Kahe 4	4.7%	7.0%	10.3%	2.9%	2.7%	4.6%
Kahe 5	0.3%	9.0%	1.1%	5.9%	4.6%	4.2%
Kahe 6	2.1%	3.3%	1.9%	3.0%	3.4%	2.7%
CIP CT-1		22.0%	16.0%	34.8%	8.4%	20.3%
HECO	**5.6%**	**5.0%**	**4.5%**	**6.3%**	**5.0%**	**5.0%**

Table 6: Historical and Forward-looking EFORd

	Recorded EFORd					AOS EFORd Rates
	2008	**2009**	**2010**	**2011**	**2012**	**2013** Forward Looking
Honolulu 8	9.3%	1.8%	17.5%	3.4%	4.0%	8.6%
Honolulu 9	5.9%	3.9%	9.1%	6.1%	24.5%	8.6%
Waiau 3	10.5%	0.8%	3.3%	11.2%	4.4%	6.1%
Waiau 4	7.2%	5.5%	0.9%	9.0%	2.2%	4.9%
Waiau 5	9.0%	2.7%	1.6%	0.5%	1.9%	2.6%
Waiau 6	0.8%	0.0%	0.2%	2.2%	6.5%	2.6%
Waiau 7	20.7%	2.4%	0.1%	6.9%	0.4%	4.6%
Waiau 8	2.9%	1.9%	1.3%	11.2%	3.7%	4.6%
Waiau 9	8.2%	1.3%	0.6%	8.6%	25.5%	7.7%
Waiau 10	5.8%	3.6%	9.0%	9.8%	4.8%	7.7%
Kahe 1	4.5%	2.3%	0.7%	2.7%	0.5%	3.8%
Kahe 2	1.6%	7.7%	8.8%	2.4%	7.2%	3.8%
Kahe 3	0.7%	3.8%	3.8%	2.2%	2.5%	4.6%
Kahe 4	4.7%	6.9%	9.7%	2.9%	2.7%	4.6%
Kahe 5	0.3%	7.9%	1.1%	6.0%	4.6%	4.0%
Kahe 6	2.0%	2.9%	1.7%	2.9%	3.4%	2.6%
CIP CT-1		18.3%	9.9%	8.4%	3.9%	10.1%
HECO	**5.6%**	**5.0%**	**4.5%**	**6.3%**	**5.0%**	**~4.1**

H-POWER	10.0%
Kalaeloa	1.5%
AES	1.5%

4.4. Planned Maintenance Schedules For The Generating Units On The System

Planned outages and maintenance outages 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 major revisions to planned and/or maintenance outages occur, the Planned Maintenance Schedule is revised.

4.5. Additions of Capacity

4.5.1 Firm Capacity Additions

The State of Hawaii Department of Transportation, Airports Division ("DOT"), plans to install approximately 8 MW of distributed standby generation ("Airport DSG") in late 2013. Under an agreement between Hawaiian Electric and DOT ("Airport DSG Agreement"), 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. The Commission approved the Airport DSG Agreement on March 2, 2010 in Docket No. 2009-0317. This capacity was included in the adequacy of supply analysis.

On May 25, 2012 in Docket No. 2012-0129, Hawaiian Electric submitted an application for approval of an Amended and Restated Power Purchase Agreement ("PPA") 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. On November 15, 2012, Hawaiian Electric filed Amendment No. 1 to the PPA. On January 17, 2013, in Decision and Order No. ("D&O") 30950, the Commission approved the PPA as Amended. The facility is forecasted to begin commercial operation in 2013, and was included in the adequacy of supply analysis.

On December 27, 2011, in Docket No. 2011-0386, Hawaiian Electric submitted to the Commission a request for approval of a waiver from the competitive bidding framework for an approximately 50 MW of utility owned and operated, firm, renewable, dispatchable, generation security project on federal land. On August 1, 2012, in D&O No. 30552, the Commission granted, subject to conditions, Hawaiian Electric's request for a waiver from the framework for competitive bidding for the purposes of allowing discussions and negotiations to occur. It is estimated that the project could be in service in the 2017 timeframe. For the purposes of this analysis, due to the level of uncertainty surrounding the service date of this facility, this capacity was not included in the analysis.

4.5.2 Non-Firm Additions

In addition to firm generation power projects, Hawaiian Electric purchases energy on an as-available basis from six producers and anticipates adding additional renewable as-available energy projects to the Hawaiian Electric system in the near future as these facilities achieve commercial operation. As-available generating units cannot be dispatched to provide a specified level of power upon demand to serve the peak load, and power from these units is not included in the planning criteria and reliability guideline calculations. Due to the increasing amount of as-available generation on the Oahu grid and the prospects for better forecasting of as-available generation, Hawaiian Electric may consider including as-available generation in its AOS analyses in the future.

Several independent as-available producers have power purchase agreements with Hawaiian Electric and are in various stages of Commission approval, or under construction. For example:

On January 19, 2011, the Commission approved a power purchase contract with Honua Power, LLC, to purchase approximately 6.6 MW of as-available energy from a biomass gasification facility. On February 27, 2013, in D&O No. 31044, the Commission approved, subject to conditions described in the D&O, the second amendment to the power purchase contract.

On October 14, 2011, Hawaiian Electric submitted its Draft Request for Proposals for Renewable Energy and Undersea Cable System Projects Delivered to the Island of Oahu, for 200 MW or more of renewable energy. On September 28, 2012, Hawaiian Electric provided an updated draft of its Request for Proposals.

On December 21, 2011, Hawaiian Electric submitted an application for Commission approval of a PPA with Kalaeloa Renewable Energy Park, LLC, for up to 5 MW of photovoltaic power. On October 22, 2012 in D&O No. 30712, the Commission approved subject to terms and conditions, the PPA between Hawaiian Electric and Kalaleoa Renewable Energy Park, LLC.

4.6. Reductions of Firm Generating Capacity

Waiau Units 3 and 4 (with a combined rating of 92.6 MW-net), and Honolulu Units 8 and 9 (with a combined rating of 107.3 MW-net) are candidates for a change in operational status such as deactivation or decommissioning in the next 10 years. The decision on whether to continue operating, deactivate, or decommission these units would depend largely on factors such as operation and maintenance costs, environmental regulations, new and replacement capacity, and transmission infrastructure improvements. For the purposes of the 2013 AOS analysis, the Reference Scenario forecasts Waiau Units 3 and 4 to be removed from service at the end of 2017, and Honolulu Units 8 and 9 to be removed from service at the end of 2019.

4.7 Capacity from Kalaeloa Partners, L.P., Combined Cycle Unit

The existing PPA with Kalaeloa Partners, L.P. ("Kalaeloa") expires on May 23, 2016. On November 10, 2011, Hawaiian Electric submitted to the Commission a Petition for Declaratory Order regarding the Exemption of Kalaeloa Partners, LP's project from the Framework for Competitive Bidding, or in the alternative, Approval of Application for Waiver from the Framework for Competitive Bidding. On May 14, 2012, in D&O No. 30380, the Commission declared that the proposed renegotiation of the amended PPA is exempt from the competitive bidding process. Hawaiian Electric is currently in discussions with Kalaeloa to renegotiate the existing PPA so that the Kalaeloa facility can continue to provide reliable firm capacity and heat rate efficient energy production through its existing facility.

For the purposes of the 2013 AOS analysis, it is assumed that the 208 MW of capacity provided by Kalaeloa remains in service beyond May 23, 2016.

4.8 Capacity from AES Hawaii, Inc.

On August 13, 2012, Hawaiian Electric submitted to the Commission a Petition for Declaratory Order regarding the Exemption of AES Hawaii's project from the Framework for Competitive Bidding, or in the alternative, Approval of Application for Waiver from the Framework for Competitive Bidding.

For the purposes of the 2013 AOS analysis, it is assumed that the 180 MW of capacity provided by AES Hawaii remains in service beyond September 1, 2022.

4.9 Environmental Considerations

The Environmental Protection Agency has established regulations with the associated compliance dates as follows:

- Reciprocating Internal Combustion Engines National Emissions Standards for Hazardous Air Pollutants ("RICE NESHAP") – May 2013.
- Mercury and Air Toxics Standards ("MATS") – Mid-2015 with potential for two, 1-year extensions on compliance deadline.
- 1-Hour SO_2 National Ambient Air Quality Standards ("NAAQS") – Compliance date in the 2022 timeframe.

The RICE NESHAPS compliance plan is underway and on schedule to achieve full compliance by the May 2013 deadline. Based on a review of the final MATS rule effective April 16, 2012, Hawaiian Electric is considering pursuing a MATS compliance strategy based on switching to lower emissions fuels. The use of lower emissions fuels will provide for MATS compliance at lower overall costs, avoid the reduction in operational flexibility imposed by emissions control equipment, achieve timely compliance with the MATS rule and provide flexibility for optimizing the combined compliance strategies for MATS and the tightening of the National Ambient Air Quality Standards. However, due to the high costs for the lower emissions fuels, Hawaiian Electric is evaluating several alternatives for lower emissions fuels with the objective of reducing costs for compliance. The current MATS compliance plan indicates compliance by April 16, 2016, which will require Hawaiian Electric to pursue a 1-year compliance extension from the Hawaii Department of Health.

Switching Hawaiian Electric's generation from oil to natural gas is the basis of Hawaiian Electric's compliance plan for the new 1-hour SO_2 NAAQS. Recent guidance from the EPA indicates that the likely compliance deadline for Hawaiian Electric will be in the 2022 timeframe which is consistent with the current schedule for bringing bulk liquefied natural gas shipments to Oahu.

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:

- Higher load forecast (60 MW increase in peak load);
- Waiau 3 and 4, and Honolulu 8 and 9 generating units remain in service
- Increased stringency of Hawaiian Electric's generating system reliability guideline from 4.5 years per day to 10 years per day.

A scenario using a lower load forecast was not performed in the analysis. However, should lower loads occur in the future, it may provide more certainty regarding decisions to deactivate or decommission existing generation units.

5.1.1 Higher Load Forecast

The Higher Load Scenario uses 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 programs, or energy efficiency 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. Table 7 summarizes the Higher Load Scenario.

Table 7: Higher Load Scenario

Year	2013 AOS Aug2012 S&P Forecast (MW)	60 MW higher Aug2012 S&P Forecast (MW)	Difference (MW)
2013	1,151	1,211	60
2014	1,163	1,223	60
2015	1,176	1,236	60
2016	1,191	1,251	60
2017	1,202	1,262	60
2018	1,209	1,269	60
2019	1,228	1,288	60
2020	1,242	1,302	60
2021	1,248	1,308	60
2022	1,242	1,302	60

5.1.2 Waiau 3 and 4; Honolulu 8 and 9

The scenario of Waiau Units 3 and 4 and Honolulu Units 8 and 9 remaining in service examines the generating system reliability if these units are not removed from service at the end of 2017, and 2019, respectively.

5.1.3 Revised System Reliability Guideline

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. The results of this high level evaluation are shown in Section 5.2.

5.2 Results of Analysis

Table 8 shows the capacity, in MW, in excess of the amount needed to satisfy Rule 1 and Rule 2 of the capacity planning criteria. The analysis shows that Rule 1 and Rule 2 are satisfied for the Reference Scenario for each year through 2017 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 4; and (2) continued acquisition of third-party energy efficiency. However, as previously explained, Rule 1 and Rule 2 results are deterministic and do not incorporate unit specific EFORd rates in their calculation.

Table 8: Rule 1 and Rule 2 Analysis
Excess Capacity Available

Year	Rule 1 Results (MW)	Rule 2 Results (MW)
2013	262	222
2014	266	226
2015	297	257
2016	303	263
2017	287	247

The LOLP for the Reference and Planning Scenarios were calculated using a production simulation model for each year through 2022 under reference and variable sets of assumptions described in Section 4.

For the years 2013 to 2019, the generating system's 4.5 years per day reliability guideline is projected to be met in the Reference Scenario and Higher Load Scenario. The scenario using a higher generating system reliability of 10 years per day is also projected to be met in this timeframe. For the years 2020-2022, the generating system reliability is projected to be less than 4.5 years per day in the Reference Scenario and Higher Load Scenario and less than 10 years per day in the higher generating system reliability scenario.

Table 9 shows the results of the Generation System Reliability analysis. The system reliability in the scenarios shown varies depending on the firm generating units available, and the planned maintenance schedules.

Table 9: *Generation System Reliability Guideline (years/day)*

Generation System Reliability (years/day)				
Year	Base Case	Higher Load (Add 60 MW)	No Retirements	10 yrs/day reliability scenario
2013	142.9	32.3	142.9	142.9
2014	166.7	35.7	166.7	166.7
2015	166.7	35.7	166.7	166.7
2016	166.7	37.0	166.7	166.7
2017	142.9	31.3	142.9	142.9
2018	24.4	6.5	200.0	24.4
2019	21.3	5.6	90.9	21.3
2020	2.2	0.7	52.6	2.2
2021	1.3	0.4	125.0	1.3
2022	2.8	0.8	142.9	2.8

Table 10 shows the reserve capacity surpluses or shortfalls corresponding to the calculated reliability shown in Table 9. 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. 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. For example in the Reference Scenario for 2020, the number -40 would indicate that about 40 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.

Table 10: Reserve Capacity Shortfall for Reference and Planning Scenarios (MW)

Year	Reference Scenario	Alternate Scenarios		
		Higher Load (Add 60 MW)	No Retirements	10 yrs/day reliability scenario
2013	140	80	140	100
2014	140	80	140	110
2015	140	80	140	110
2016	150	90	150	110
2017	140	80	140	100
2018	70	10	160	30
2019	70	10	130	30
2020	-40	-100	110	-80
2021	-70	-130	140	-100
2022	-30	-90	140	-60

(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 greater projected capacity shortfall in the years 2020-2022 in contrast to the 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.

Table 10 further projects that for the years 2020 to 2022, approximately 60 MW to 100 MW of firm capacity would have to be added to the Hawaiian Electric system to achieve a higher reliability guideline of 10 years/day in the near term. The 30 to 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.

6. Acquisition of Additional Firm Capacity

6.1 Competitive Bidding is the Required Acquisition Mechanism

On December 8, 2006, the Framework for Competitive Bidding ("CB Framework") was adopted by the Commission in Decision and Order No. 23121, in Docket No. 03-0372, pursuant to HRS §§ 269-7 and 269-15 and Hawaii Administrative

Rules § 6-61-71. The Commission's CB Framework states that "[c]ompetitive bidding, unless the Commission finds it to be unsuitable, is established as the required mechanism for acquiring a future generation resource or a block of generation resources, whether or not such resource has been identified in a utility's IRP."[17]

As indicated above, Hawaiian Electric will need additional firm capacity beginning in the 2019 timeframe in anticipation of the potential change in operational status or deactivation of Waiau Units 3 and 4 at the end of 2017 and Honolulu Units 8 and 9 at the end of 2019. Hawaiian Electric will seek to acquire the additional firm capacity through a competitive bidding process.

In addition, as indicated in Section 4.5, Hawaiian Electric is continuing to pursue the addition of approximately 50 MW of utility owned and operated, firm, renewable, dispatchable, generation security project on federal lands, for the purpose of ensuring that the Army's critical national security and first responder missions can be carried on. It is estimated that the project could be in service in the 2017 timeframe, which would change the timing and amount of the reserve capacity shortfall.

6.2 Scope of Request For Proposals ("RFP") for Additional Firm Capacity

Section II.B.1. of the CB Framework states "An electric utility's IRP shall specify the proposed scope of the RFP for any specific generation resource or block of generation resources that the IRP states will be subject to competitive bidding." The Integrated Resource Planning ("IRP") process for Hawaiian Electric, Hawaii Electric Light Company, Inc. and Maui Electric Company, Limited is currently in progress in Docket No. 2012-0036. The scope of Hawaiian Electric's RFP will be defined in the IRP filing targeted for June 2013.

7. Conclusions

Under the Reference Scenario, Hawaiian Electric's generation capacity for the next seven years (2013-2019) will be sufficient to meet reasonably expected demands for service and provide reasonable reserves for emergencies, with accommodations for environmental compliance options.[18] Hawaiian Electric will need additional firm capacity in the 2019 timeframe, and will seek to acquire the additional capacity through a competitive bidding process.

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17 CB Framework, Section II.A.3. on page 3.

18 As a result of the higher reserve margins currently available and the lower forecasted peak loads, Hawaiian Electric is evaluating the operational status of its generating units, including consideration to "deactivate" selected units, and plans to implement changes once the evaluation is completed in order to achieve generation operating efficiencies. While these efficiencies should result in cost savings, they should not affect the adequacy of supply analyses.

The scenario analysis indicates that depending on system conditions, Hawaiian Electric may experience anywhere from a 10 MW reserve capacity surplus under the Higher Load Scenario to a 70 MW reserve capacity surplus in the Reference Scenario in the 2018-2019 timeframe. By 2020, Hawaiian Electric may experience anywhere from a 40 MW to 130 MW reserve capacity shortfall under these scenarios. A portion of potential reserve capacity shortfalls may be addressed through mitigation measures such as the acquisition of additional energy efficiency and load management resources over the near-term (if approved by the Commission), or adjustments to Hawaiian Electric's planned maintenance schedules, depending on the circumstances.

Hawaiian Electric must, therefore, be proactive, anticipating the what-ifs, and cannot count on the Reference Scenario occurring. Hawaiian Electric will continue its portfolio approach to meet its obligation to serve, which includes increased renewable energy contributions, demand-side management programs and the pursuit of firm capacity renewable supply side options. Hawaiian Electric also recognizes that the environment for resource planning has increased in complexity and uncertainty.

Very truly yours,

for Patsy H. Nanbu
Vice President
Regulatory Affairs

Attachments

c: Division of Consumer Advocacy (with Attachments)

Table A1:
Projected Reserve Margins

Year	System Capability at Annual Peak Load (net kW) [A] (I)	System Peak (net kW) [D] (II)	Interruptible Load (net kW) [E] (III)	Reserve Margin (%) [A-(D-E)] / (D-E)
2012	1,755,600	1,151,000	37,658	58%
2013	1,790,600	1,151,000	45,246	62%
2014	1,790,600	1,163,000	49,277	61%
2015	1,790,600	1,176,000	56,629	60%
2016	1,790,600	1,191,000	63,527	59%
2017	1,790,600	1,202,000	69,489	58%
2018	1,698,000	1,209,000	74,471	50%
2019	1,698,000	1,228,000	82,854	48%
2020	1,590,700	1,242,000	91,233	38%
2021	1,590,700	1,248,000	99,899	39%
2022	1,590,700	1,242,000	108,565	40%

Notes:

I. System Capability includes:
- Hawaiian Electric central station units at total normal capability is 1,321,600 kW-net or 1,383,000 kW-gross.
- Firm power purchase contracts with a combined net total of 434,000 kW in 2012 from Kalaeloa (208,000 kW), AES Hawaii (180,000 kW), and H-POWER (46,000 kW).
- Expected expansion of H-POWER in 2013 (+27,000 kW)
- Expected addition of Airport DSG in 2013 (8,000 kW)
- Kalaeloa assumed to continue in service after 2016
- AES Hawaii assumed to continue in service after 2022
- Waiau Units 3 and 4 are removed from service in 2017 (-92,600 kW)
- Honolulu Units 8 and 9 are removed from service in 2020 (-107,300 kW)

II. System Peaks
- The 2013-2022 annual forecasted system peaks are based on Hawaiian Electric's August 2012 Sales and Peak Forecast.
- The forecasted System Peaks for 2013-2022 include the estimated peak reduction benefits of third-party energy efficiency DSM programs.
- The peak for 2013-2022 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.

III. Interruptible Load:

- Interruptible Load impacts are at the net-to system level, and are approximate impacts at the system peak.

Equivalent Demand Forced Outage Rate Definition and Formula

As defined in IEEE Std-762-2006 [19], Section 3.8:

Equivalent Demand Forced Outage Rate ($EFOR_d$): A measure of the probability that a generating unit will not be available due to forced outages or forced deratings when there is demand on the unit to generate.

$EFOR_d$ is defined in the NERC GADS Data Reporting Instructions[20], Appendix F as:

$$EFORd = \frac{[FOHd + (EFDHd)]}{[SH + FOHd]} \times 100\%$$

where

FOHd = f x FOH
EFDHd = (EFDH – EFDHRS) if reserve shutdown events reported, or
= (fp x EFDH) if no reserve shutdown events reported – an approximation.
fp = (SH/AH)

$$f = \left(\frac{1}{r} + \frac{1}{T}\right) / \left(\frac{1}{r} + \frac{1}{T} + \frac{1}{D}\right)$$

r=Average Forced outage deration = (FOH) / (# of FO occurrences)
D=Average demand time = (SH) / (# of unit actual starts)
T=Average reserve shutdown time = (RSH) / (# of unit attempted starts)

An example of the application of the EFORd formula to Hawaiian Electric's Waiau 9 generating unit in 2012 is shown below:

	Service Hours	Reserve Shutdown Hours	Available Hours				Equivalent Forced Derated Hours	Forced Outage Hours	
Capacity	SH	RSH	AH	Actual Starts	Attempted Starts	Failed Starts	EFDH	FOH	FO Events
53	67	7002.14	7069	26	27	1	0.00	1,067.26	5

=1/ (1067/5)	=1/(7002/27)	=1/(67/26)		=0.021397 *1067	=67/7069	=0.009416* 0		=(22.84/(67+22.84)) *100	=(1067/(1067+67)) *100
1/r	1/T	1/D	f	fxFOH	fp	fp x EFDH	EFORd x MW	**EFORd**	**EFOR**
0.004685	0.003856	0.390625	0.021397	22.83591142	0.009416	0	1,353.87	**25.54**	**94.1**

19 http://www.nerc.com/docs/pc/gadstf/ieee762tf/762-2006.pdf
20 http://www.nerc.com/page.php?cid=4|43|45

Hawaiian Electric Equivalent Forced Outage Rate ("EFORd") Discussion

It is extremely difficult to predict unit-specific EFORd 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 2013 AOS analysis and the rationale for them are described in the following paragraphs.

1. <u>Honolulu Units 8 and 9</u>

In the 2012 AOS, the forward looking EFOR of 15.2% included the actual average of 5 years for both H8 and H9. The actual EFOR for 2012 for Honolulu Units 8 & 9 were 8.3% and 60.9%, respectively, and averaged 34.6% for the two units. For the 2013 AOS analysis, it was decided to utilize the EFORd formula and the average of the actual EFORd for both units for the past 5 years. This approach recognizes that these units will be dispatched and operated similarly in 2013 as they were in recent years. As a result, an EFORd of 8.6% is recommended for the 2013 AOS forward looking EFORd for both Honolulu Units 8 and 9.

2. <u>Waiau Units 3 and 4</u>

In the 2012 AOS, the forward looking EFOR for Waiau Unit 3 was 16.8%. The actual EFOR for 2012 for Waiau Unit 3 was 9.4%. The actual EFOR was lower than the forecast. For the 2013 AOS analysis, it was decided to use the EFORd formula and the average of the actual EFORd rates for the past 5 years. This approach recognizes that Waiau Unit 3 will be dispatched and operated similarly in 2013 as it was in recent years. Thus, for Waiau Unit 3, an EFORd of 6.1% is recommended for the 2013 AOS forward looking EFORd.

In the 2012 AOS, the forward looking EFOR for Waiau Unit 4 was 11.5%. The actual EFOR for 2012 for Waiau Unit 4 was 5.7%. The actual EFOR was significantly lower than the forecast. For the 2013 AOS analysis, it was decided to use the EFORd formula and utilize the average of the actual EFORd of the unit for the recent 5 years. This approach recognizes that Waiau Unit 4 will be dispatched and operated similarly in 2013 as it was in recent years. Thus, for Waiau Unit 4, an EFORd of 4.9% is recommended for the 2013 AOS forward looking EFORd.

3. Waiau Units 5 and 6

In the 2012 AOS, the forward looking EFORs for Waiau Units 5 and 6 were 3.9% based on the average actual EFORs for both units for the recent 5 years. The actual EFOR for 2012 for Waiau Units 5 and 6 were 4.0% and 15.7%, respectively. For both units, actual EFORs were above forecast. For the 2013 AOS analysis, it was decided to use the EFORd formula and the average of the actual EFORd rates for the past 5 years. This approach also recognizes that the units will be dispatched and operated similarly in 2013 as they were in recent years. As a result, an EFORd of 2.6% is recommended for the 2013 AOS forward looking EFORd 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 2012 AOS, the forward looking EFOR rate of 5.3% was used for these four units. The actual EFOR for 2012 for Waiau 7, Waiau 8, Kahe 3, and Kahe 4 were 0.4%, 3.7%, 2.5%, 2.7%, respectively, with an average of 2.3%. For the 2013 AOS analysis, it was decided to use the EFORd formula and the average of the actual EFORd rates for the four units for the past 5 years. This approach also recognizes that these units will be dispatched and operated similarly in 2013 as they were in recent years. As a result, an EFORd of 4.6% is recommended for the 2013 AOS forward looking EFORd for Waiau Units 7 and 8, and Kahe Units 3 and 4.

5. Waiau Units 9 and 10

In the 2012 AOS, the forward looking EFORs for Waiau Units 9 and 10 were 20.3% based on the average of the actual EFORs for both units for the recent 5 years. The actual EFOR in 2012 for Waiau Units 9 and 10 were 94.1% and 14.5%, respectively, and averaged 54.3% for the two units. The actual EFOR were significantly higher than the forecast. For the 2013 AOS analysis, it was decided to use the EFORd formula and the average of the actual EFORd rates for both units for the past 5 years. This approach also recognizes that these units will be dispatched and operated similarly in 2013 as they were in recent years. As a result, an EFORd of 7.7% is recommended for the 2013 AOS forward looking EFORd for Waiau 9 and 10.

7. Kahe Units 1 and 2

In the 2012 AOS, the forward looking EFORs for Kahe Units 1 and 2 were 3.9% based on the average of the actual EFORs for both units for the recent 5 years. The actual EFOR in 2012 for Kahe Unit 1 and 2 were 0.5% and 7.2%, respectively, and averaged 3.9% for both units. For the 2013 AOS analysis, it was decided to use the EFORd formula and average of the actual EFORd rates for both units for the past 5 years. This approach also recognizes that these units will be dispatched and operated similarly in 2013 as they were in recent years. As a result, an EFORd of 3.8% is recommended for the 2013 AOS forward looking EFORd for Kahe 1 and 2.

8. Kahe Unit 5

In the 2012 AOS, the forward looking EFOR for Kahe Unit 5 was 3.8% based on the average of the actual EFOR for the recent 5 years. The actual EFOR of 4.6% was higher than the forecast. For the 2013 AOS analysis, it was decided to use the EFORd formula and the average of the actual EFORd rate for the past 5 years. This approach recognizes that this unit will be dispatched and operated similarly in 2013 as it was in recent years. As a result, an EFORd of 4.0% is recommended for the 2013 AOS forward looking EFORd for Kahe 5.

9. Kahe Unit 6

In the 2012 AOS, the forward looking EFOR for Kahe Unit 6 was 2.1% based on the average of Kahe Unit 6 actual EFOR for the recent 5 years. The actual EFOR for 2012 for Kahe Unit 6 was 3.4%. For the 2013 AOS analysis, it was decided to use the EFORd formula and the average of the actual EFORd rate for the past 5 years. This approach also recognizes that Kahe Unit 6 will be dispatched and operated similarly in 2013 as it was in recent years. As a result, an EFORd of 2.6% is recommended for the 2013 AOS forward looking EFORd for Kahe Unit 6.

10. CIP CT-1

On August 3, 2009, CIP CT-1 was placed in service (e.g. tied into the electrical grid and producing power). The actual EFOR for 2009, 2010, 2011, and 2012 was 22.0%, 16.0%, 34.8%, and 8.4%, respectively, with an average of 20.3% over the four years. For the 2013 AOS analysis, it was decided to use the EFORd formula and the average of the actual EFORd rate for the past 4 years. This approach recognizes that this unit will be dispatched and operated similarly in 2013 as it was in recent years. As a result, an EFORd of 10.1% is recommended for the 2013 AOS forward looking EFORd for CIP CT-1.