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

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February 27, 2007

William A. Bonnet
Vice President
Government & Community Affairs

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PUBLIC UTILITIES COMMISSION

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.

In accordance with paragraph 5.3a. of General Order No. 7, the following information is respectfully submitted[1].

I. Executive Summary

On March 6, 2006, HECO filed its annual Adequacy of Supply report to the Commission ("2006 AOS") in which HECO concluded that until sufficient generating capacity could be added to the system, HECO would experience a higher risk of generation-related customer outages, and reserve capacity shortfalls that were more frequent and longer in duration. Under the Reference Scenario, the 2006 AOS expected a reserve capacity shortfall[2] of 170 MW to 200 MW in the 2006-2009 period (without including the addition of the Campbell Industrial Park combustion turbine in 2009).

HECO's latest estimates for this 2007 AOS place the reserve capacity shortfall for the Reference Scenario at approximately 70 MW in the 2007-2008 period (including the impact of 30 MW of temporary leased, distributed generating units at HECO sites to mitigate the shortfall,

1 HECO's Adequacy of Supply ("AOS") Report is due within 30 days after the end of the year. On January 26, 2007, HECO requested an extension of time, to no later than March 30, 2007, to file the Report. The extension of time was needed to allow HECO to better assess and incorporate the impact of its most recent generation availability experience (calendar year 2006) to determine the estimated reserve margin capacity shortfall for the period covered by this letter. The Commission granted HECO's request by letter dated February 1, 2007.

2 "Reserve capacity shortfall" is defined as the amount of additional firm generating capacity or equivalent reductions in load from load management and energy efficiency demand-side management ("DSM") programs and/or combined heat and power ("CHP") installations needed to restore the generating system reliability above HECO's reliability guideline.

pending the installation of new long-term capacity). Under this Reference Scenario, HECO also estimates that the reserve capacity shortfall would be in the range of 20 to 40 MW for years 2009-2012, if the nominal 110 MW Campbell Industrial Park combustion turbine is installed in mid-2009, and the temporary, utility-sited distributed generation units are not included[3].

While the decrease in the projected reserve capacity shortfall is due to a combination of factors, the primary reason for the reduction in reserve capacity shortfall between the 2006 AOS and the 2007 AOS is the reduction in the peak load forecast. Figure ES-1 illustrates the May 2005 peak forecast used in the 2006 AOS, the August 2006 peak forecast used in the 2007 AOS, a High Load scenario used in the 2007 AOS, and recorded system peaks. Recognizing the difficulties in forecasting system peaks even three or four years into the future, and understanding that higher peaks will translate into larger reserve capacity shortfalls, HECO performed a High Load scenario analysis with peaks that are higher than the August 2006 forecast (but lower than the peaks forecast in May 2005).

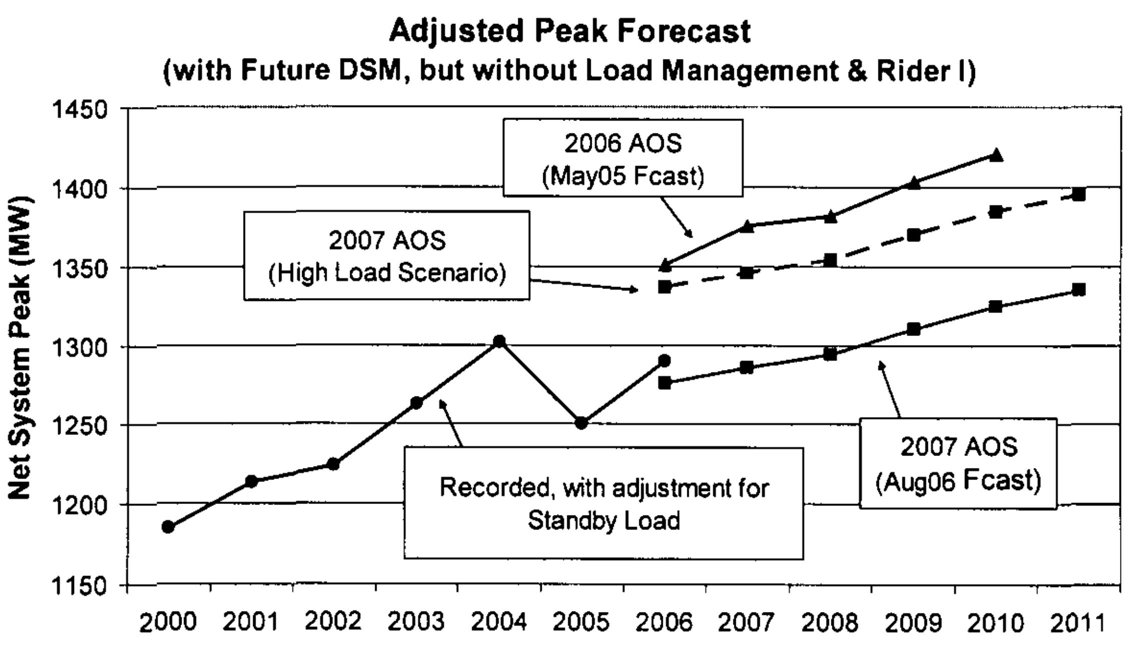

Figure ES-1: Recorded Peaks and Future Year Projections

In addition to the High Load scenario analysis, HECO performed sensitivity analyses for scenarios with different estimates for unit availability. One sensitivity scenario assumed an

[3] On September 28, 2006, HECO filed Rebuttal Testimony in the Campbell Industrial Park Generating Station and Transmission Additions Project (Docket No. 05-0145), in which HECO's reference scenario reduced the estimate of the reserve capacity shortfall to approximately 90 MW in the 2007–2008 period.

additional two-month outage of a 90 MW unit, as a proxy for real-life, unplanned outages that have occurred in the past, and may occur again in the future. For example, HECO Waiau Unit 8 experienced a forced outage in October 2005 due to a feedwater heater failure that also damaged the turbine. Forced outage repairs were completed in February 2006. Forward-looking EFOR assessments and Planned Maintenance Schedules do not fully capture this type of unplanned, prolonged unavailability, and therefore it is prudent to evaluate this scenario. Another sensitivity analysis used 5-year average EFORs for HECO generating units, which resulted in lower projected EFORs assumed for most of HECO's baseload units. HECO does not expect generating unit EFORs to converge toward a 5-year mathematical average; however, this sensitivity does allow HECO to evaluate the reduction in reserve capacity shortfall due to this change in assumed EFORs.

The reserve capacity shortfalls associated with these scenarios are shown in Table ES-1, and assume that the Campbell Industrial Park combustion turbine is installed in mid-2009. Capacity from the temporary, HECO-sited distributed generators is not included in the estimates beginning in 2010 in order to identify the true reserve capacity situation following the installation of the combustion turbine, absent capacity from temporary mitigation measures. Reserve capacity shortfall is the amount of additional firm generating capacity needed to restore the generating system Loss of Load Probability to greater than the 4.5 years per day reliability guideline. For example, the number "-50" would indicate that 50 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 ES-1:
Reserve Capacity Shortfall for Reference
and Single-Sensitivity Scenarios, MW
Nominal 110MW CT installed in Mid-2009

Year	Reference Scenario	Alternate Scenario (Higher Load)	Alternate Scenario (Two-Month 90 MW Outage)	Alternate Scenario (5-Yr Avg EFOR)
2007	-70	-130	-90	-60
2008	-70	-130	-90	-60
2009	-40	-100	-50	-30
2010	-40	-100	-50	-40
2011	-20	-80	-40	-10
2012	-20	-80	-50	-20

HECO also evaluated the impact of compound assumption changes, combining the impacts of better EFOR (5-year average) with a higher load. In another compound scenario, HECO combined the higher load scenario with the two-month outage of a 90 MW unit. The reserve capacity shortfalls associated with these compound scenarios are shown in Table ES-2, again assuming that the Campbell Industrial Park combustion turbine is installed in mid-2009, but without counting the capacity from the temporary, HECO-sited distributed generators beginning in 2010.

Table ES-2:
Reserve Capacity Shortfall for
Reference and Compound Scenarios, MW
Nominal 110MW CT installed in Mid-2009

Year	Reference Scenario	Alternate Compound Scenario (60 MW Higher Load with 5-Yr Avg EFOR)	Alternate Compound Scenario (60 MW Higher Load with Two-Month 90 MW Outage)
2007	-70	-120	-150
2008	-70	-120	-150
2009	-40	-90	-110
2010	-40	-100	-110
2011	-20	-70	-100
2012	-20	-80	-110

The single and compound sensitivity scenarios indicate that the magnitude of the reserve capacity shortfall is highly dependent on the load forecast. Generally, the reserve capacity shortfall appears to increase in a roughly MW-for-MW fashion for increases in the load forecast (which could come about through faster-than-anticipated organic load growth, less load-reducing impacts from energy efficiency DSM or load management, or a combination of these components).

Until sufficient generating capacity can be added to the system, HECO will experience a higher risk of generation-related customer outages, and reserve capacity shortfalls that are more frequent and longer in duration. HECO does not foresee this situation improving in the near-term.

HECO has made progress toward the installation of the combustion turbine at Campbell Industrial Park and is optimistic that the nominal 110 MW increment of firm capacity can be added to the system by mid-2009. However, HECO also assessed the reserve capacity shortfall under the scenario where the combustion turbine is not installed, in Appendix 6.

HECO has taken a number of steps to mitigate the effects of reserve capacity shortfalls, such as installing distributed generators (DG) at substations or other sites, implementing additional load management and other demand reduction measures, and pursuing efforts to improve the availability of generating units. HECO cannot, however, completely eliminate reserve capacity shortfalls in the near-term. HECO will operate at lower-than-established reliability levels and take steps to mitigate the reserve capacity shortfall situation until the next generating unit is installed.

After the planned mid-2009 addition of the Campbell Industrial Park generating unit, and in recognition of the uncertainty underlying key forecasts, HECO anticipates the potential for continued reserve capacity shortfalls which could range between 20 MW to 110 MW in the 2009 to 2012 period. Any plan to install additional firm capacity is required to proceed under the guidance of the Competitive Bidding Framework issued by the Commission on December 8, 2006 in D&O 23121.

II. Adequacy of Supply

1. Peak Demand and System Capability in 2006

HECO's 2006 system peak occurred on Monday, August 28, 2006 and was 1,315,000 kW-gross or 1,266,000 kW-net based on net HECO generation, net purchased power generation, the peak reduction benefits of energy efficiency demand-side management programs implemented beginning in mid-1996, and with several cogenerators[4] operating at the time. Had these cogenerating units not been operating, the 2006 system peak would have been approximately 1,338,700 kW-gross or 1,289,700 kW-net.

HECO's total generating capability of 1,657,400 kW-net at the time of the 2006 system peak included 434,000 kW-net of firm power purchased from (1) Kalaeloa Partners, L.P. ("Kalaeloa"), (2) AES Hawaii, Inc., and (3) H-POWER. Oahu had a reserve margin of approximately 30% over the 2006 system net peak.[5] Subsequent to the 2006 system peak, approximately 9.8 MW of temporary, distributed generation was installed at two HECO sites on November 8, and December 20, 2006. Another 4.9 MW of temporary, HECO-sited distributed generation is being installed, and startup testing is scheduled to begin by the end of the first quarter of 2007. This will bring the total to 29.5 MW of temporary, HECO-sited, distributed generation.

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

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[4] At the time of the peak, certain units at Tesoro, Chevron and Pearl Harbor were generating an estimated 23,700 kW of power for use at their sites.

[5] The reserve margin calculation includes 17,400 kW of interruptible loads served by HECO.

2. Estimated Reserve Margins

Appendix 1 shows the expected reserve margin over the next three years, based on HECO's August 2006 Sales and Peak Forecast, and HECO's latest estimates of acquired DSM impacts for 2006, forecasted enhanced energy efficiency DSM impacts, forecasted load management DSM impacts, and forecasted non-utility CHP impacts.

3. Relevant Events Since the 2006 Adequacy of Supply Report:

On March 6, 2006, HECO filed its annual Adequacy of Supply report with the Commission ("2006 AOS") in which HECO concluded that until sufficient generating capacity could be added to the system, HECO would experience a higher risk of generation-related customer outages, and reserve capacity shortfalls that were more frequent and longer in duration. Under the Reference Scenario, the 2006 AOS expected a reserve capacity shortfall of 170 to 200 MW in the 2006–2009 period (without including the addition of the Campbell Industrial Park combustion turbine in 2009). Appendix 5 of the 2006 AOS described the uncertainties in HECO's capacity planning, including actual daily load versus forecasted loads, non-dispatchable as-available energy, actual energy efficiency DSM impacts versus forecasted impacts, actual load management DSM impacts versus forecasted impacts, actual outage schedule versus forecasted outage schedule, and assumed Equivalent Forced Outage Rates ("EFORs"). Recognizing the uncertainties in planning assumptions, Section 4.3.2 and Appendix 6 of the 2006 AOS provided the results of sensitivity analyses, which illustrated how the capacity shortfall could change under various scenarios. As described below, some of the circumstances that occurred in 2006 were similar to scenarios tested in the 2006 AOS sensitivity analysis. For example, recognizing the uncertainty in capacity planning assumptions, the 2006 AOS provided sensitivity results under a lower load scenario and also under a lower EFOR scenario. In 2006, HECO did experience lower peaks than forecast, and generally, somewhat lower EFORs for its generating units. As illustrated in the 2006 AOS (Section 4.3.2 and Appendix 6), a reduction of either of these items will tend to reduce the magnitude of the reserve capacity shortfall. This 2007 AOS also makes use of sensitivity analyses, recognizing that the Reference Scenario is one of many possible futures.

Since HECO filed its 2006 AOS, there have been changes in certain planning assumptions, and events have occurred that will affect its assessment of the adequacy of supply on Oahu. These include (1) the development of a new short-term sales and peak forecast in August of 2006, (2) reassessment of forward-looking generating unit availabilities[6], (3) approval in the Energy Efficiency Docket (Docket No. 05-0069) of HECO's proposed energy efficiency DSM programs by the Commission, and the establishment of January 2009 as the target date for the transition of the energy efficiency DSM programs to a non-utility administrator, (4) filing of an application to amend the Commercial and Industrial Direct Load Control ("CIDLC") Program,

[6] See Section 3.3 for a discussion of generating unit availabilities.

and approval by the Commission of a request to add control of residential central air conditioning to the Residential Direct Load Control ("RDLC")Program[7], and (5) progress made in HECO's efforts to install firm generation in Campbell Industrial Park.

3.1. August 2006 Peak Forecast

HECO developed a new short-term sales and peak forecast in August 2006 ("August 2006 forecast"), which was subsequently adopted for planning purposes. This forecast superseded the May 2005 short-term sales and peak forecast used in the 2006 AOS.

The near-term outlook for the local economy used as the basis for the August 2006 forecast did not change substantially from the outlook used for the May 2005 update. Hawaii's economy in 2006 was largely performing to expectations for continued growth, although somewhat more slowly than 2005's banner year. The construction industry continued to be strong and tourism, despite some early weakness, was expected to recover in the second half of 2006. Unfortunately, inflation remained relatively high and was expected to persist at or above 3.0% through 2008. Hawaii's economy was expected to continue to grow in the short-term despite higher inflation, although at a slower rate than that experienced in recent years.

While continued local economic growth was expected to support growth in electricity sales, growth in the residential sector was expected to moderate somewhat after strong increases over the last few years. Residential customers may be affected by eroding disposable income as interest rates rise from historical lows and housing and energy costs rise. Commercial sector growth was also expected to moderate as the construction and tourism industries stabilize after peaking in recent years.

A comparison of the May 2005 peak forecast and the August 2006 peak forecast is shown in Table 1 below.

[7] On February 13, 2007, in the Energy Efficiency Docket D&O No. 23258, the Commission ordered that load management programs (e.g., the CIDLC and RDLC Programs) continue to be administered by the utilities.

Table 1:
Comparison of Forecasted Peak Loads
(Without impacts of 2006 and thereafter Energy Efficiency DSM and Load Management DSM, Utility CHP and Non-utility CHP)

Year	May 2005 Forecast System Peak (Net MW)	August 2006 Forecast System Peak[8] (Net MW)	Decrease in Peak Forecast[9] (MW)
2006	1,356	1,281	-75
2007	1,390	1,300	-90
2008	1,408	1,317	-91
2009	1,440	1,342	-98
2010	1,468	1,364	-104
2011	N/A	1,381	N/A
2012	N/A	1,397	N/A

The August 2006 peak forecast is lower than the May 2005 peak forecast largely as a result of lower forecasted sales. While the economy has remained strong, both residential and commercial sales have been below recent forecast expectations. Weather appeared to be a factor in 2005–2006 sales performance, with cooler, less humid weather lowering sales after a very hot, humid 2004. In addition, double digit increases in electricity prices beginning in mid-2005 appear to have dampened residential use. The May 2005 forecast projected sales to grow by 2.6% in 2006 over forecasted growth of 0.9% in 2005. However, actual sales decreased by 0.1% in 2005, and at the time the August 2006 forecast was issued, actual 2006 sales were 0.9% below 2005 sales. These lower than previously anticipated sales levels were reflected in the August 2006 sales forecast. The August 2006 forecast expected sales to decline 0.9% in 2006, and resume moderate growth on an average of 1.1% per year for 2007–2011. Ko Olina development, several new large condominiums, and military construction were expected to contribute to commercial sector growth over the forecast horizon.

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[8] The August 2006 Sales and Peak Forecast covers the period 2006 –2011. The estimate for 2012 peak was extrapolated from the 2011 peak, using the escalation factors from the February 2004 Long Term Sales and Peak Forecast.

[9] Decrease in Peak Forecast may not add, due to rounding.

3.1.1. 2006 System Peak

HECO's 2006 system peak of 1,315 MW-gross or 1,266 MW-net occurred on August 28, 2006. The 2006 annual peak was 42 MW-gross or 36 MW-net higher than the system peak of 1,273 MW-gross or 1,230 MW-net which occurred on September 14, 2005. During the time of the peak, several cogenerators were running and either delivering energy (on an as-available basis) to the HECO system or partially offsetting their on-site loads. If these units had not been running, HECO's peak would have been approximately 1,339 MW-gross or 1,290 MW-net. This 2006 adjusted peak was approximately 55 MW-net lower than the peak projected in the May 2005 forecast, but was approximately 12 MW-net higher than the 2006 peak projection in the August 2006 forecast.

Forecast peaks are derived on a weather normalized basis, thus forecast peaks do not represent an "upper bound" of what actual peaks may be. HECO's generation system needs to be able to serve the actual peak, irrespective of the weather situation.

Although the system peak in 2006 fell short of the May 2005 forecast value, and the 2004 peak remains the highest yet recorded on the HECO system, HECO's system peak increased in 2006 over 2005. It is not unusual that a new system peak would not occur every year. However, the fact that Hawaiian Electric has actually experienced demand at the level seen in 2004 demonstrates that the potential exists for at least that level of demand. In other words, appliances, machinery, and other equipment sufficient to produce the 2004 peak level of demand do exist, and are connected to our grid.

It is likely that more equipment and appliances were added in 2005 and 2006. In addition to growth in the commercial sector, in the last two years a large number of homes on Oahu have likely purchased window air conditioners, big screen TV's, video game units, set top DVR boxes, home computers and printers, MP3 players, and many other devices that use electricity. Given the proper confluence of weather, electric appliances, and economic events, HECO will undoubtedly continue to see higher levels of demand than have been recorded in past years.

Figure 1 illustrates HECO's historical system peaks and compares them to forecasts used in the 2006 AOS reference case and 2007 AOS reference case. For the 2007 AOS, a higher load scenario was also analyzed to evaluate the reserve capacity shortfall under situations where peaks are higher than forecast. In part, this sensitivity scenario was evaluated because of the large reduction in estimated peak between the May 2005 peak forecast (2006 AOS) and the August 2006 peak forecast (2007 AOS), and because the 2006 recorded peak exceeded the peak forecast for 2006. 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 (Chevron, Tesoro and Pearl Harbor) that are frequently served by their own internal generation.

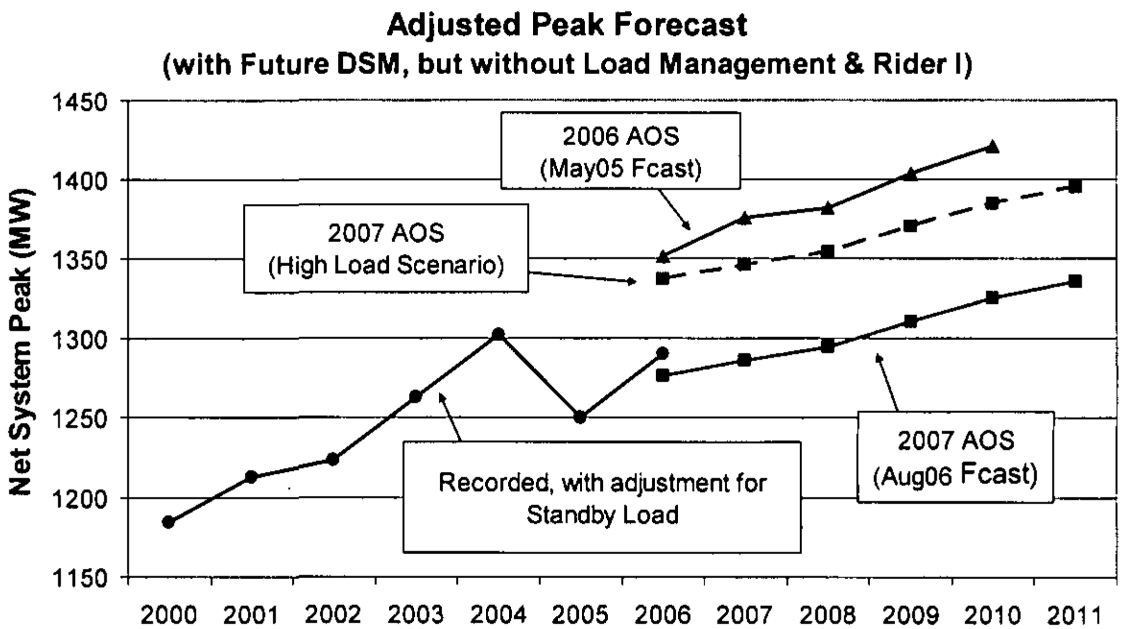

Figure 1: Recorded Peaks and Future Year Projections

As described in the 2006 AOS, rising demand over time – even if at a slower pace than previously forecast – will have the effect of reducing the reserve margin (i.e., the reserve capacity, which is the difference between the total installed capacity less the peak demand). The declining reserve margin will continue to reduce the flexibility HECO has in scheduling outages for maintenance of the generating units, and responding to unanticipated generating unit forced outages or deratings. This is because HECO must try to maintain an amount of spinning reserve necessary to cover for the unexpected loss of the largest unit. The total system capacity less the capacity of the largest unit less the system peak leaves the amount of capacity that can be taken off the system for maintenance. As the peaks increase, the amount of capacity that can be taken off the system for maintenance decreases.

3.2. Forward-looking EFOR

As explained in Section 4, HECO's capacity planning criteria are applied to determine the adequacy of supply and whether or not there is enough generating capacity on the system. HECO's capacity planning criteria consists of two rules and one reliability guideline. The reserve capacity shortfalls calculated herein are determined by the application of the reliability guideline, which involves a Loss of Load Probability ("LOLP") calculation. The outputs of the LOLP calculation are driven by the input assumptions. The key input assumptions include the load to be served, the amount of firm capacity on the system, and the availabilities of the generating units. The EFOR of a generating unit is one of the key determinants of the availability of the unit.

EFOR, or equivalent forced outage rate, is the rate at which forced outages and forced derates occur. EFOR is a subset of generating unit availability and accounts for unanticipated shutdowns caused by forced outages and generating unit deratings caused by equipment problems that allow operation of the generating unit, but at a lower level of output. An example of a generating unit derating's impact on EFOR is if a unit is limited to 90% of full power because of an equipment malfunction, its EFOR (without any forced outages) would be 10% for the duration of the derating.

EFOR is a parameter used in traditional long-term planning and integrated resource planning ("IRP") to determine when and how much capacity is needed to provide established levels of generation-related electric service as determined by HECO's reliability planning guideline. For traditional long-term planning, utilities may average the historical individual unit EFORs by similar unit types and over an extended time period (for example, 5 or 10 years). This method may provide the approximate reliability of each type of generating unit over the long-term. However, past experience is not always an accurate indicator of future performance. EFORs may vary as operating conditions change.

HECO's composite generating unit EFOR has historically compared favorably to the industry average for similar types and sizes of units. As an isolated island utility without interconnections, HECO has had to strive for lower EFORs compared to mainland utilities because HECO cannot rely on neighboring utilities for reserve capacity.

Table 2 provides recorded HECO EFOR data by unit for the period 2000 to 2006. The Forward-Looking EFOR values are utilized in the Reference Scenario of the 2007 AOS, and are based on a combination of historical data, experience, and operational judgment. Additional information on EFOR is discussed in Appendix 7. As explained therein, the Forward-Looking EFOR assumption generally reflects the 3-year average of the specific unit, or group of similar units. Generally, these values are lower than those assumed in the 2006 AOS. This assessment reflects the general – but not universal -- EFOR reduction observed in

2006 (in comparison to 2004 and 2005). However, EFOR projections are uncertain, and actual experience may differ from the projections made.

The reserve capacity shortfall has been growing in recent years as the annual peak demand has been increasing. A consequence of this pattern has been increased reliance on HECO's cycling and peaking units[10], and in particular, the needs to cycle these units off and on more frequently and to operate these units more hours per year. The more arduous duty cycles on these units results in cyclic thermal stresses and accelerated wear on auxiliary equipment and critical components, and consequently, the potential for increased EFOR rates.

The ages of the units also played a large role in the higher EFORs in recent years. Generating units are made up of very complex systems and equipment that wear and tear at different rates as they age. Older mechanical and electrical equipment are prone to break down more frequently than newer equipment.

The EFOR values in the row titled "HECO" represent a HECO-system composite EFOR that takes into account the size and operating hours on each unit.

[10] The cycling units are Waiau Units 3 to 6 and Honolulu Units 8 and 9. The peaking units are Waiau Units 9 and 10, which are combustion turbines.

Table 2: Historical and Forward-looking EFORs

	2000	2001	2002	2003	2004	2005	2006	5 Year Average 2002-2006	Forward-Looking EFOR Base	AOS 2006 EFOR Base
H8	7.2%	10.4%	3.6%	13.0%	23.7%	1.7%	3.1%	9.0%	11.3%	12.8%
H9	1.4%	3.0%	3.1%	20.0%	1.0%	12.0%	26.1%	12.4%	11.3%	12.8%
W3	2.0%	1.9%	6.5%	10.9%	24.7%	42.2%	24.0%	21.7%	11.3%	33.5%
W4	3.0%	14.8%	5.1%	3.4%	13.4%	5.0%	27.2%	10.8%	11.3%	12.8%
W5	3.6%	0.8%	2.2%	4.1%	1.0%	1.0%	1.7%	2.0%	2.6%	2.9%
W6	3.8%	3.9%	0.6%	2.8%	0.3%	2.6%	9.2%	3.1%	2.6%	2.9%
W7	0.7%	1.6%	1.8%	0.7%	1.2%	0.6%	1.1%	1.1%	6.6%	7.7%
W8	5.3%	1.5%	0.1%	0.0%	7.7%	23.5%	18.5%	10.0%	6.6%	7.7%
W9	65.7%	4.1%	49.9%	6.9%	63.2%	69.2%	14.7%	40.8%	12.7%	10.0%
W10	13.4%	5.0%	13.6%	36.0%	4.4%	7.4%	26.3%	17.5%	12.7%	10.0%
K1	1.2%	0.7%	2.3%	1.2%	2.6%	5.4%	1.6%	2.6%	3.2%	4.3%
K2	1.7%	3.1%	1.0%	2.2%	2.9%	2.0%	0.9%	1.8%	3.2%	4.3%
K3	0.3%	3.9%	0.1%	3.5%	8.8%	8.3%	2.1%	4.5%	6.6%	7.7%
K4	5.7%	0.9%	3.6%	1.3%	1.4%	4.9%	1.4%	2.5%	6.6%	7.7%
K5	1.7%	0.4%	1.0%	1.1%	7.6%	3.1%	3.1%	3.2%	4.6%	5.5%
K6	0.9%	0.4%	0.5%	1.9%	3.3%	5.9%	2.8%	2.9%	4.0%	4.9%
HECO	**2.4%**	**1.6%**	**1.8%**	**2.4%**	**~6.2%**	**~9.25%**	**~5.3%**	**~ 5.4%**	**~ 5.4%**	**~ 6.8%**
H-POWER									10.0%	10.0%
Kalaeloa									1.5%	1.0%
AES									1.0%	1.0%

Table 2 also illustrates the EFOR projections for Independent Power Producers. There have been no recent changes to the EFOR assumptions used for H-POWER and AES. However, recent experience and interaction with Kalaeloa indicate that an increased EFOR assumption – from 1.0% to 1.5% -- is appropriate. Currently Kalaeloa has been experiencing increased outage time related to water or steam leaks from heat recovery steam generators (HRSG). This issue was summarized in a September 15, 2006 letter from HECO to Kalaeloa (see Docket No. 2006-0386, HECO-WP-501). Kalaeloa is taking steps to address this problem and it is projected that as a result, EFOR will not increase substantially above the 1.5% level experienced in the most recent Contract Year (June 2005 through May 2006). However, the 1.5% level is above the historical average level of about 1.0% EFOR experienced in the earlier years of plant operation.

3.3. <u>HECO Generating Unit Planned Outages and Maintenance Outages</u>

Each generating unit has two possible states: either it is available (i.e., it is operating or on stand-by, ready to serve load) or unavailable. When a unit is available, it can be fully available (i.e., it is able to operate at its full capability) or partially available (i.e., it is derated or able to operate only at less that its full capability).

A unit may be unavailable for three reasons: (a) it is on planned outage (i.e., on scheduled overhaul); (b) it is on a maintenance outage (i.e., out of service on a scheduled basis to repair a problem on the unit); or (c) it is on forced outage (i.e., unexpectedly forced out of service).

One measure of generating unit availability is the Equivalent Availability Factor ("EAF"). It can generally be thought of as the percent of the time a unit is available to serve demand, taking into account periods of time when the unit is only partially available.

HECO's composite generating unit EAF has historically compared favorably to the industry average for similar types and sizes of units. As an isolated island utility without interconnections, HECO has had to maintain a higher EAF than mainland utilities because HECO cannot rely on neighboring utilities for reserve capacity.

Forced outages and deratings reduce generating unit availability and are accounted for in the EFOR statistic. Planned outages and maintenance outages also reduce generating unit availabilities. As reserve margins continue to shrink, it becomes more challenging to take units out of service for planned or maintenance outages or to provide maintenance scheduling flexibility.

The scheduling of planned overhaul and maintenance outages is dynamic in nature. When extensions to planned outages occur, or problems are discovered such that an outage is needed to address it, or forced outages occur, the Planned Maintenance Schedule must be revised. Also, as peak demand increases, reserve capacity decreases, and the amount of capacity that can be taken off the system for maintenance decreases. This reduces the flexibility in rearranging the Planned Maintenance Schedule. The dynamic nature of scheduling outages was discussed in HECO's 2007 Rate Case [DT-6 at 20] where three changes to the Planned Maintenance Schedules occurred from February 14, 2006, to November 21, 2006.

Notwithstanding the dynamic nature of maintenance scheduling, for the 2007 AOS, emphasis was placed on developing an assumption for planned outages and maintenance outages in which the unavailable MWh due to these two types of outages were levelized over the forward-looking period 2007-2012. First, HECO completed an estimate of 2007 planned maintenance in preparation for its 2007 test year rate case, and the resulting Planned Maintenance Schedule was used in the rate case production simulation (direct testimony). Then, for this 2007 AOS, it was determined that the 2007 Planned Maintenance Schedule assumed in the 2007 test year rate case direct testimony was a reasonable best-estimate for the type and quantity of planned outages. Therefore, the unavailable MWh from the Planned Maintenance Schedule were used as a benchmark for levelizing unavailable MWh for years 2008 and beyond. In the 2006 AOS, HECO explained that planned maintenance schedules identified year-ahead outage requirements (and unavailable MWh) more completely than in the period two to four years into the future, and therefore, the 2006 AOS also employed a levelizing technique in an effort to improve future-year analytical results.

3.4. Load Management DSM, Energy Efficiency DSM, Rider I, and CHP Impacts

The load reducing impact acquired from HECO's existing energy efficiency DSM, load management DSM, and Rider I in 2006 was approximately 24 MW[11]. This recorded load reducing impact was consistent with the projections for 2006 in the 2006 AOS report for the impacts of HECO's proposed load management DSM and the continuation of existing energy efficiency DSM. However, the overall 2006 impact resulted from an over-performance of the energy efficiency programs offset by under-performance in Commercial and Industrial Direct Load Control Program. The 2006 AOS report did not project any 2006 impacts for CHP, and none were acquired. Further, the 2006 AOS projected that combined impacts from load management DSM, Rider I, energy efficiency DSM, and CHP would be approximately 79 MW by 2009. The projection of the combined impacts for the 2007 AOS has been reduced to approximately 73 MW by 2009, as shown in Table 3, below. This reduction in MW impact is primarily due to the slight under-performance of the CIDLC Program in its first two years of implementation and a reduced forecast of CHP installations.

[11] For look-ahead planning purposes, the 2006 AOS and 2007 AOS both assume that HECO's system peak will occur in the month of October. The 2006 system peak was unusual in that it was a day peak (rather than evening peak), and it occurred in August. It is estimated that the total load reduction available to HECO in August 2006 -- from load management, Rider I, and energy efficiency – was approximately 19 MW (less than the corresponding assumption for October 2006, since HECO had approximately 2 months less to acquire the peak-reducing impacts).

Table 3:
Previous and Current Projections of
Load Management DSM, Rider I, Energy Efficiency DSM, and CHP[12] (MW)

	Load Management		Rider I		Energy Efficiency DSM		CHP		**Total Load Reduction**		
Year	2006 AOS	2007 AOS	2006 AOS	2007 AOS	2006 AOS	2007 AOS	2006 AOS	2007 AOS	**2006 AOS**	**2007 AOS**	**Diff**
2006	15	13	5	5	4	5	0	0	**24**	**23**	**-2**
2007	22	19	5	5	13	14	1	0	**41**	**38**	**-3**
2008	30	28	5	5	23	22	4	1	**62**	**56**	**-5**
2009	37	36	5	5	32	30	5	2	**79**	**73**	**-6**
2010	42	42	5	5	41	37	7	2	**94**	**86**	**-8**
2011	43	45	5	5	49	43	9	3	**105**	**96**	**-10**
2012	43	45	5	5	58	48	10	3	**115**	**101**	**-14**

On December 29, 2006 HECO submitted to the Commission an Amendment to the CIDLC Program Application requesting a number of modifications to the program intended to correct this under-performance. Implementation of these modifications will, in time, lead to greater load reductions in the CIDLC program, but in the near term the under-performance is not anticipated to be made up before 2009. The CIDLC Program impacts included in Table 3 assume that approval of the program modifications is received in early 2007 for implementation by mid-2007. The application is currently pending at the Commission.

Larger differences between the 2006 and 2007 AOS projections for energy efficiency DSM program impacts through 2012 are primarily due to a change in the assumption regarding the demand savings from certain DSM measures beyond the service lives of the measure. As further detailed in Appendix 2, the 2006 AOS assumption was that savings from the replacement of the original measure after the measure service life was attained could be considered a result of the DSM programs. The 2007 AOS assumption is that the savings beyond the measure service life is included in the sales and peak forecast as naturally

12 To allow equivalent-basis comparison to 2007 AOS projections, 2006 AOS figures are reduced by 2005 Acquired impacts. The 2006 AOS did not present data for year 2011-2012, but it is being included here for comparative purposes. Rider I is not considered a load management program, but is assumed to reduce the peak for planning purposes. Rider I planning assumptions have not changed between the 2006 AOS and the 2007 AOS. For capacity planning purposes, until it gains more experience with the nature of interruptible loads, HECO limits the modeled penetration of its interruptible loads (Load Management + Rider I) to 50 MW. Totals may not add, due to rounding.

occurring conservation. The energy efficiency DSM program impact assumptions identified in Table 3 assumed that a Decision and Order in the Energy Efficiency Docket approving HECO's proposed energy efficiency DSM programs would be issued early in 2007 and implemented by mid-year. HECO's Energy Efficiency Docket proposal consisted of enhancements to its existing programs[13] and a new DSM program, (Residential Low Income Program). On February 13, 2007, the Commission, in Decision and Order No. 23258, approved HECO's proposed DSM programs and the Residential Customer Energy Awareness ("RCEA") Program, initially proposed by HECO in its 2005 test year rate case (Docket No. 04-0113). The Decision and Order confirms the validity of the assumed implementation schedule underlying the energy efficiency program impacts in Table 3.

Decision and Order No. 23258 filed February 13, 2007 in Docket No. 05-0069 stated that "All of the HECO Companies' Energy Efficiency DSM programs shall transition from the HECO Companies to the Non-Utility Market Structure, by January 2009, unless otherwise ordered by the commission. The HECO Companies' Load Management programs shall be excluded from the third-party administrator's area of responsibility."

Please refer to Appendix 2 for additional information regarding HECO's load management DSM programs and enhanced energy efficiency DSM programs.

The 2007 AOS forecast for CHP reflects non-utility installations only, and at a very modest level. This comes as a result of (1) new rules issued by the U.S. Environmental Protection Agency ("EPA") which will require more stringent emission controls for stationary diesel engines in the near future, (2) limitations on the ability of HECO to provide customer-sited DG projects on a regulated utility basis, and (3) other uncertainties concerning customer-sited DG. The impacts for CHP are small relative to load management and energy efficiency DSM. The actual amount of non-utility CHP that will be installed in the future is uncertain.

As illustrated in Table 3, the forecast for total load reduction from load management, Rider I, Energy Efficiency DSM, and CHP decreased from the 2006 AOS to the 2007 AOS. The reduction is relatively small in the years 2007–2010, but increases steadily through 2012. Absent any changes in the unadjusted load forecast, this would increase the expected load to be served. However, when combined with the large reduction in unadjusted peaks (illustrated in Table 1), the net result is that the 2007 AOS Reference Scenario forecasts a reduction in the hourly load that must be served (relative to the 2006 AOS Reference Scenario).

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[13] HECO's existing energy efficiency programs consist of the Commercial and Industrial ("C&I") Energy Efficiency ("CIEE"), C&I New Construction ("CINC"), C&I Customized Rebate ("CICR"), Residential Efficient Water Heating ("REWH"), Residential New Construction ("RNC"), and Interim Energy Solutions for the Home ("ESH") Programs.

3.5. Next Generating Unit Addition

With the anticipation of adding a nominal 110 MW simple-cycle combustion turbine in 2009, HECO began the process of preliminary engineering work for this project in 2002 and began efforts to obtain the Covered Source Permit ("air permit") in January 2003. HECO submitted an initial application for the air permit with the State of Hawaii Department of Health ("DOH") in October 2003. The air permit contains provisions to use alternate fuels such as ethanol and biodiesel. In December 2004, HECO submitted an amendment to its initial air permit application, in part as a contingency plan to allow for the possibility that a second simple-cycle combustion turbine may be needed sooner than projected (for example, if the first combustion turbine, energy efficiency DSM and load management do not fully satisfy system demands). HECO continues with efforts to permit, design, and install its next generating unit and a 2-mile long 138 kV transmission line between the AES substation and CEIP substation. Since the filing of the 2006 AOS in March 2006, these efforts include:

- On July 18, 2006, the Honolulu City Council adopted a resolution to amend the Public Infrastructure Map to include the proposed new generating facility.
- The Final Environmental Impact Statement (FEIS) was accepted by the Department of Planning and Permitting on August 10, 2006[14]. Announcement of the FEIS availability was made in the August 23, 2006 *Environmental Notice.*
- A Public Utilities Commission evidentiary hearing for the community benefits package was held on November 29, 2006. Opening Briefs were filed on January 8, 2007 and Reply briefs were filed on January 22, 2007.
- A draft air permit was released by the DOH in November 2006, and a public hearing was held in December 2006. DOH is currently reviewing and addressing the comments received.
- A Public Utilities Commission evidentiary hearing for the project was held the week of December 11, 2006. Opening Briefs are to be filed on March 2, 2007, and Reply Briefs are to be filed on March 16, 2007.
- Continuing detailed engineering design to support long lead time "ministerial permits," such as the building permit and grubbing and grading permit.

Given the long lead time of the permitting, engineering, equipment procurement and construction activities, it appears that 2009 is still the earliest that installation of the planned simple-cycle combustion turbine can be expected to be completed.

[14] Since the unit addition is planned to be greater than 5 MW, an Environmental Impact Statement is required by HRS Chapter 343.

4. HECO Capacity Planning

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

4.1. HECO's Capacity Planning Criteria

HECO's capacity planning criteria consist of two rules and one reliability guideline. As noted in Section 3.3 (Forward-looking EFOR), the reserve capacity shortfalls calculated herein are determined by the application of the reliability guideline, where the key inputs to the application of the reliability guideline are the EFORs of each generating unit.

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 HECO will not build reserve capacity to serve interruptible loads, interruptible load programs such as HECO's current Rider I and recently approved RDLC and CIDLC programs 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, in MW, that would be available for interruption at that time, subtract the capacity, in MW, of the unit or units that are unavailable due to planned maintenance, subtract the capacity, in MW, of the largest available unit, and determine whether the result is greater than or less than the system peak, in MW, 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.

4.2. <u>HECO's Reliability Guideline: Loss of Load Probability</u>

The application of HECO's generating system reliability guideline does take into account the probabilities that generating units could be unexpectedly lost from service. The EFORs of the generating units are key inputs to the LOLP calculation in the application of the guideline.

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 HECO's generating system reliability guideline.

HECO has a reliability guideline threshold of 4.5 years per day. HECO 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. Please refer to Appendix 3 of the 2005 AOS for additional information related to HECO's reliability guideline.

LOLP is a measure of the probability on a given day of not having sufficient generation available to serve the system load, due to forced outages of one or multiple generating units (owned by HECO or IPPs). LOLP is computed using a day-by-day computer simulation that takes into account projected system daily peak loads to be served by central station generation, scheduled maintenance, and unit forced outage rates (expressed as equivalent forced outage rate, or EFOR). Energy efficiency DSM programs, interruptible load management DSM programs, and customer-sited CHP resources also have an effect of reducing the daily peak load that has to be served, so they affect the LOLP calculation as well.

While LOLP provides an indication of the probability that the peak demand may or may not be served, it does not provide a measure of the expected duration of outages due to insufficient generation, the magnitude (in MW) of the outage, or the projected number of unserved kilowatthours (kWh) or customers due to insufficient generation.

In addition, probabilistic results are a mathematical expectation that may differ from observed results. For example, the probability that a tossed coin will land on "tails" is 50%. However, this is no guarantee that a coin tossed 10 times will result in 5 tails. Similarly, a system with an expected LOLP of 4.5 years per day could experience two generation shortfall incidents in a single year (an observed LOLP = 0.5), or it could experience one incident in five years (an observed LOLP = 5.0), or it could experience one incident in ten years (an observed LOLP = 10.0). The fact that an observable generation shortfall incident did not occur precisely at the expected interval should not lead one to conclude that the system has become more or less reliable than calculated, it merely confirms that random events like forced outages – even when characterized as mathematical probabilities – are still random.

Other reasons for the variance between mathematical expectation and observable generation shortfall incidents include actual conditions, such as actual load being lower than projected load, or the degree to which critical situations are managed to address the shortfall. For example, in 2006, HECO issued public calls for conservation on January 10, June 1, and June 2 when reserve margins were expected to be especially thin approaching the evening peak demand period. Another call for public conservation was also made on February 1, 2007. HECO's recent calls for extra conservation helped to reduce the electrical load on the system, however, the impacts of this community response cannot be assumed for capacity planning purposes. The consumer is under no obligation to undertake emergency conservation measures on a routine basis or when asked by the utility (the utility encourages all customers to practice conservation as a general habit). This reduction in load would be an example of events that may occur, but are not "counted on" when calculating the mathematical expectation for insufficient generation events.

In general, the application of HECO's reliability guideline results in a need for more generating capacity on the system compared to that required by the HECO Rule 1 or HECO Rule 2 planning criteria. The reliability guideline is probabilistic - it takes into consideration that forced outages from one or more generating units may result in not having sufficient generation capacity to meet the peak load demand. HECO Rule 1 and HECO Rule 2 criteria are deterministic – they only take into consideration that the forced outage from the largest available generating unit may result in not having sufficient capacity to meet the peak load demand.

Whether or not there are actual outages due to insufficient generation as projected by the HECO reliability guideline will depend on factors that impact (1) the actual system load to be served by central station generation, (2) the actual scheduled maintenance of generating units, and (3) the actual EFORs for such units. The actual system load to be served by central station generation will be affected by (1) actual daily loads (versus forecasted loads and load profiles), (2) non-dispatchable as-available energy contributions, and (3) actual energy efficiency DSM and load management DSM peak impacts (versus forecasted impacts). (See Appendix 5 for a detailed discussion of uncertainties in HECO capacity planning).

4.3. Analysis Results

4.3.1. Reference Scenario

4.3.1.1. Generating System Reliability Analysis

Table 4 provides the LOLP calculated using a production simulation model for each year through 2012 under a reference set of assumptions including: (1) continued acquisition of residential and commercial load management impacts, including modifications to these programs to add residential air-conditioning load control and commercial and industrial demand load response elements; (2) implementation of its Interim DSM Proposals in July 2006 and its enhanced energy efficiency DSM programs beginning in mid-2007, (3) the inclusion of approximately 29.5 MW of temporary, HECO-sited distributed generation through 2009 (reflecting installations in 2005, 2006, and 2007), and (4) the addition of the CIP simple-cycle combustion turbine in June 2009.

In addition, the results in Table 4 are based upon the use of forward-looking EFORs for all existing generating units, both HECO-owned and IPP. The analysis reflected in Table 4 projects that generating system reliability will be less than the 4.5

years per day reliability guideline in 2007 and continuing through 2012. Under these projections, a generation-related customer outage is likely to occur more frequently than that provided for in the reliability guideline.

As explained above, these results assume that HECO is able to install its simple-cycle combustion turbine in the 2009 timeframe. This differs from the 2005 AOS and 2006 AOS analyses, which did not include installation of the combustion turbine as a reference case assumption. While HECO expects that the new generating unit will be installed, Appendix 6 provides analytical results for a scenario that does not have the CIP combustion turbine installed. The Reference Scenario analysis does not include capacity from the temporary distributed generation units at HECO sites after the Campbell Industrial Park combustion turbine is added in mid-2009. This was done to more accurately reflect the true reserve capacity situation at this time, without considering contributions from temporary mitigation measures such as the distributed generators. The distributed generation units could be left in service beyond 2009, but they were not designed as long-term generating resources. HECO has the option to continue to operate the distributed generators as a mitigation measure if there continues to be a reserve capacity shortfall after the combustion turbine is added.

Table 4:
Generation System Reliability
(Reference Load Management DSM,
Energy Efficiency DSM, and EFOR)
HECO Reliability Guideline: 4.5 years/day

Year	Generation System Reliability (years/day)
2007	1.1
2008	1.1
2009	2.1
2010	2.0
2011	3.2
2012	3.3

Table 5 shows the reserve capacity shortfall corresponding to the calculated reliability shown in Table 4. Reserve capacity shortfall is the approximate amount of additional firm generating capacity needed to restore the generating system LOLP to be greater than the 4.5 years per day reliability guideline. For example, the number "-50" would indicate that 50 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 5:
Reserve Capacity Shortfall
(Reference Load Management DSM,
Energy Efficiency DSM, CHP, and EFOR)

Year	Reserve Capacity Shortfall (MW)
2007	-70
2008	-70
2009	-40
2010	-40
2011	-20
2012	-20

4.3.1.2. HECO Rule 1 and Rule 2 Analysis

Table 6 shows that HECO's Rule 1 and Rule 2 criteria do not forecast a reserve capacity shortfall for the period 2007-2012. 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
(Reference Load Management DSM,
Energy Efficiency DSM, and CHP)

Year	Rule 1 Results (MW)	Rule 2 Results (MW)
2007	88	48
2008	56	16
2009	83	43
2010	108	68
2011	94	54
2012	152	112

4.3.2. Sensitivity Analysis

The results of HECO's Reference Scenario analysis reflect one of many possible futures, as the calculation of reserve capacity shortfall is dependent on uncertain assumptions (the uncertainty of planning assumptions are described in Appendix 5). To evaluate the ramifications of differing assumptions, HECO performed analyses based on scenarios that illustrate the relationship between certain key inputs, or combination of inputs, and the resulting reserve capacity shortfall. Descriptions of the various sensitivity scenarios are provided in the paragraphs below.

As discussed in Section 3.4, the timing and magnitude of the combined peak reduction benefits from HECO's proposed enhanced energy efficiency DSM programs and the load management DSM programs are uncertain. Further, HECO has no assurances that the peaks estimated in the August 2006 Sales and Peak forecasts will occur precisely as anticipated, notwithstanding that HECO believes this latest forecast is the most representative of likely sales and peak load. Therefore, HECO assessed a scenario where organic load growth is higher than forecast, and/or peak reductions from energy efficiency DSM and load management DSM are less than anticipated.

The alternative higher load scenario uses a very simplistic assumption: adjusted peaks are higher by 60 MW in comparison to the Reference Scenario. Such a scenario is possible, for example, if (1) customer acceptance and/or awareness is less than expected in the case of the residential and commercial and industrial load management programs, or HECO's enhanced energy efficiency DSM programs; (2) electricity use is higher than that projected by the August 2006 Sales and Peak forecast; or (3) a combination of these factors occurs to some degree in the future.

While an increase of 60 MW in adjusted peak load may appear large at first, Figure 1 illustrates that this Higher Load Scenario (for the 2007 AOS) is still lower than the May 2005 Sales and Peak forecast utilized in the 2006 AOS, the best-available forecast in use by HECO a year ago. Moreover, the actual 2006 system peak load exceeded the August 2006 Sales and Peak forecast by approximately 12 MW. While growth in sales on the HECO system has been relatively flat from 2004 through 2006, system peak demand as recently as 2004 was 1,281 MW-net, which was a marked increase of approximately 39 MW above the peak demand in 2003 (1,242 MW-net), showing that a potential for a high peak demand for electricity, beyond that forecast in any given year, exists on the system[15].

In addition, the uncertainty in achieving energy efficiency DSM and load management peak reduction benefits targeted in the Reference Scenario increases the further out into the future such projections are made. Table 3 indicates that the Total Load Reduction from load management, Rider I, energy efficiency DSM, and CHP is forecast to be approximately 38 MW in 2007, but grows to approximately 101 MW by 2012. If, for example, 75% of the forecast Total Load Reduction is achieved[16] in 2007, that would translate to a Total Load Reduction of approximately 29 MW instead of the 38 MW forecast in the Reference Scenario. In this example, the shortfall in Total Load Reduction would further increase to approximately 25 MW by 2012 (75% of 101 MW is approximately 76 MW).

Decision and Order No. 23258 filed February 13, 2007 in Docket No. 05-0069 stated that "All of the HECO Companies' Energy Efficiency DSM programs shall transition from the HECO Companies to the Non-Utility Market Structure, by January 2009, unless otherwise ordered by the commission. The HECO Companies' Load Management programs shall be excluded from the third-party administrator's area of responsibility." HECO has not quantified the potential impact of this D&O on the forecast for energy efficiency in the years beyond 2009; however, transition to a third-party administrator in 2009 creates even greater uncertainty in the Energy Efficiency DSM program impact assumptions used in the Reference Scenario.

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15 Factors such as periods of unusually hot or humid weather can contribute to unanticipated spikes in peak load demand, as occurred in 2004.

16 HECO can pursue and facilitate, but does not have total control over, securing regulatory approval of load reducing programs and measures, or customer adoption of such measures once regulatory approval is gained.

In view of these considerations, HECO determined that analysis of a Higher Load Scenario was prudent. Table 7 below compares the peaks used in the Reference Scenario with the peaks used in the Higher Load Scenario.

Table 7:
Comparison of the Peaks: Reference versus
Higher Load Sensitivity
(Peaks reduced by Future Energy Efficiency DSM, Load
Management, Non-Utility CHP, and Rider I)

	Adjusted System Peak (Net MW)		
Year	Reference	Higher Load	Difference
2007	1262	1322	60
2008	1261	1321	60
2009	1269	1329	60
2010	1278	1338	60
2011	1285	1345	60
2012	1296	1356	60

HECO performed a sensitivity analysis assuming 5-year average EFORs for HECO generating units, which resulted in lower projected EFORs assumed for most of HECO's baseload units. This average is designed to include a blend of two "better" years (2002 & 2003), two "worse" years (2004 & 2005), and a year that falls in between (2006). The unit-specific EFOR values, including the 5-year average EFOR values, were provided in Table 2. HECO does not expect future EFOR to converge towards a 5-year mathematical average; however, this sensitivity scenario allows HECO to evaluate the reduction in reserve capacity shortfall due to a moderate reduction in EFOR.

HECO also performed a sensitivity analysis assuming a higher EFOR, based on the extended-duration outage of a generating unit, to analyze the impacts of such an event. For example, HECO Waiau Unit 8 experienced a forced outage in October, 2005 due to a feedwater heater failure that also damaged the turbine. Forced outage repairs were completed in February, 2006, which largely accounted for a Waiau Unit 8 EFOR of 23.5% in 2005 and 18.5% in 2006 (as shown in Table 2). However, the forward-looking EFOR that HECO is using for Waiau Unit 8 in the Reference Scenario is approximately 6.6% in the years 2007 and beyond, which is based on actual EFORs for similar units (including Waiau Unit 7, Waiau Unit 8, Kahe Unit 3, and Kahe Unit 4), as well as 3-year averages (2004-2006). The scenario analysis allows HECO to consider the impact of a much higher EFOR for a generation unit in any given year (refer to Appendix 7 for an explanation of the forward-looking, unit specific EFORs estimated in the Reference Scenario). Similarly, although HECO believes that a reasonable forward-looking EFOR estimate for Waiau Unit 9 is approximately 12.7%, this unit did in fact experience a forced outage that straddled both 2004 and 2005. Consequently, recorded EFOR rates recorded for Waiau Unit 9 were 63.2% in 2004, and 69.2% in 2005.

While the reference case, forward-looking EFORs are HECO's best-estimate for its generating units, on average over time, actual experience should be considered. If an unplanned, extended duration outage of a HECO generating unit occurred in the past, it could certainly occur in the future[17], and it is important to understand the consequences on system reliability.

Accordingly, depending on the year, HECO used either Kahe 3 or Kahe 4 as the proxy unit, simulating an additional period of unavailability lasting two months, beginning in June of each year. Either Kahe 3 or Kahe 4 was selected because these units 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.

Table 8 and Figure 2 shows the reserve capacity shortfalls for the Reference scenario, alternate higher load scenario, alternate two-month outage scenario, and the alternate 5-year average EFOR scenario.

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[17] Practically speaking, HECO cannot predict exactly which specific utility unit or IPP unit will experience extended-duration unavailability, nor can it precisely predict when it will occur, or how long it will last. Still, HECO has developed a reasonable proxy scenario for the purposes of examining the sensitivity of this key factor and its related impact on the reserve capacity shortfall.

Table 8:
Reserve Capacity Shortfall for Reference
and Single-Sensitivity Scenarios, MW

Year	Reference Scenario	Alternate Scenario (Higher Load)	Alternate Scenario (Two-Month 90 MW Outage)	Alternate Scenario (5-Yr Avg EFOR)
2007	-70	-130	-90	-60
2008	-70	-130	-90	-60
2009	-40	-100	-50	-30
2010	-40	-100	-50	-40
2011	-20	-80	-40	-10
2012	-20	-80	-50	-20

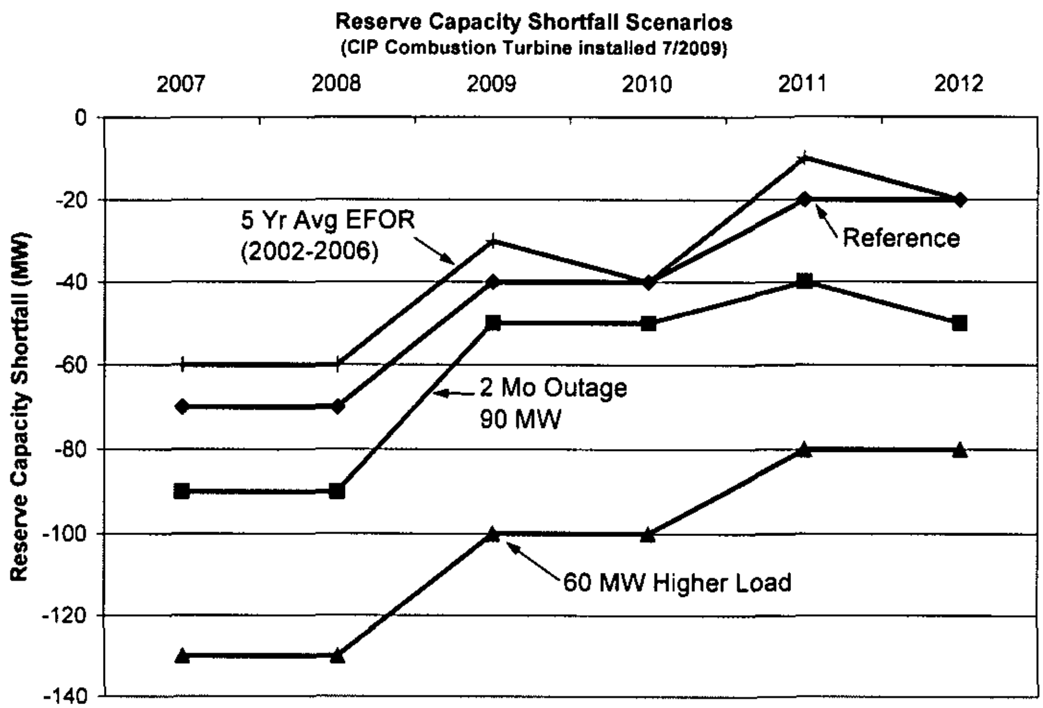

Figure 2: Reserve Capacity Shortfall for Reference and Single-Sensitivity Scenarios

A few observations from these sensitivity results are worth noting:

First, the reserve capacity shortfall calculation is very sensitive to the load forecast. In the case of the Higher Load Scenario, a nominal 60 MW increase in forecasted load resulted in 60 MW being added to the reserve capacity shortfall. Yet, as Figure 1 illustrates, the Higher Load Scenario used in this sensitivity analysis is actually lower than the May 2005 forecast utilized in the 2006 AOS. Expectations regarding future loads can change quickly. As will be explained later, however, HECO may not be able to respond quickly to increases in demand, which illustrates the importance of using sensitivity analysis as a planning tool.

Second, the Two-Month 90 MW Outage Scenario appears to add approximately 20 MW to the reserve capacity shortfall. The moderate increase in reserve capacity shortfall is a function of when (in the year) the 90 MW is unavailable. As explained previously, HECO elected to perform this sensitivity using neither the "best" nor "worst" time of the year to make the 90 MW unavailable. In a real life situation, however, it is not likely that HECO will have control over when an extended-duration outage of a HECO or IPP unit occurs, and therefore, the analytical results of this scenario should not be misinterpreted as the "typical" impact on system reliability.

Third, the 5-Year Average EFOR assumption illustrates that a moderate reduction in reserve capacity shortfall, approximately 10 MW or so, may be achieved with a moderate reduction in EFOR. As previously explained, however, actual generating unit EFOR in any given year may deviate substantially from a multi-year historical average. Still, the results of this sensitivity analysis are useful in gauging the impact that reduced EFOR could have on system reliability.

In addition to the single-assumption-change scenarios described above, HECO also evaluated the impact of combined assumption changes, with the results illustrated in Table 9, below. For the first compound scenario, HECO combined the impacts of 5-year average EFOR with a higher load (+60 MW). For the second compound scenario, HECO combined higher loads with the two months outage of a 90 MW unit. This compound scenario was evaluated under the rationale that higher loads foster operating and maintenance conditions that may increase the potential for unit unavailability over and above the Reference Scenario. As expected, since both assumption changes will negatively impact system reliability, the combination of these two factors results in a pronounced increase in reserve capacity shortfall over the Reference Scenario.

Table 9:
Reserve Capacity Shortfall for Reference and Compound-Sensitivity Scenarios, MW

Year	Reference Scenario	Alternate Compound Scenario (60 MW Higher Load with Lower EFOR)	Alternate Compound Scenario (60 MW Higher Load with Two-Month 90 MW Outage)
2007	-70	-120	-150
2008	-70	-120	-150
2009	-40	-90	-110
2010	-40	-100	-110
2011	-20	-70	-100
2012	-20	-80	-110

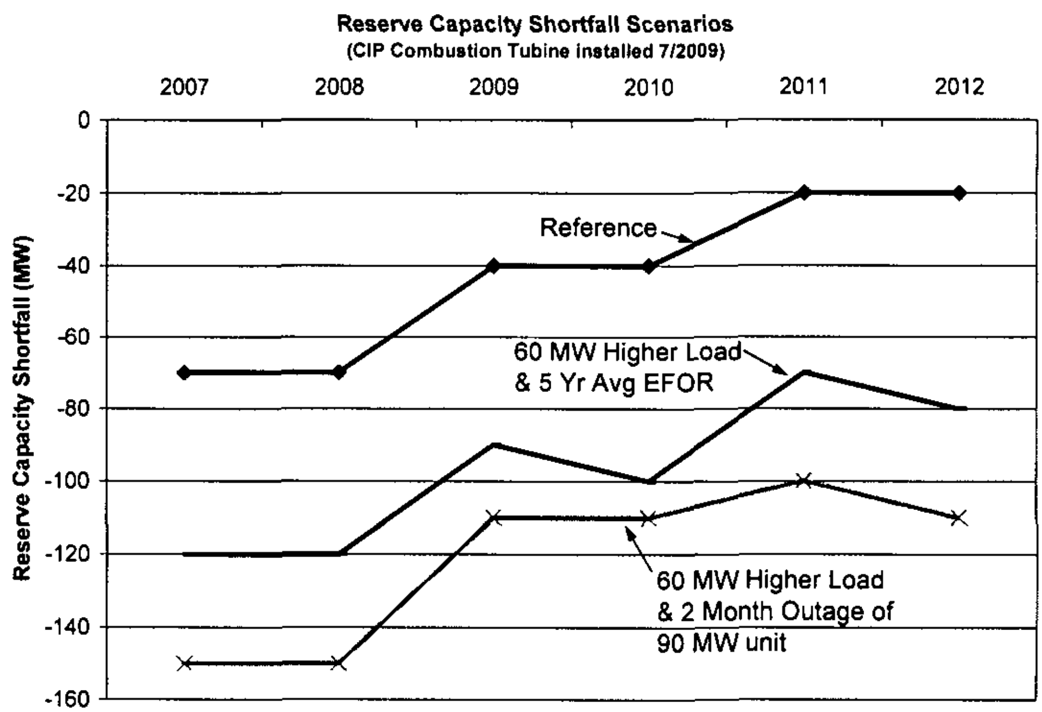

Figure 3: Reserve Capacity Shortfall for Reference and Compound-Sensitivity Scenarios

(See Appendix 6 for additional quantifiable results for the Alternate Scenarios).

Tables 4 through 9 show that, even with the installation of the combustion turbine at Campbell Industrial Park in mid-2009, a pronounced reduction in the forecast system peaks, significant impacts from energy efficiency DSM and load management, and improvements in generating unit availability, a reserve capacity shortfall ranging from 20 MW to 110 MW is projected for the 2009–2012 period, assuming that the 30 MW of temporary mitigation DG units at HECO sites are not counted.

The sensitivity scenarios indicate that the magnitude of the reserve capacity shortfall is highly dependent on the load forecast. Generally, the reserve capacity shortfall appears to increase in a roughly MW-for-MW fashion for increases in the load forecast (which could come about though faster-than-anticipated organic load growth, less load-reducing impacts from energy efficiency DSM or load management, or a combination of these components). This conclusion is important because changes to the load forecast can be quick and pronounced. It is difficult enough to forecast system peaks over the next two or three years, but the uncertainty is even greater for periods four to five years out (2011 - 2012 period). Unfortunately, permanent supply-side options of sizable scale that can effectively address the reserve capacity shortfall can take many years to implement.

For example, in its December 2002 IRP-2 Evaluation report, HECO estimated that a new generating unit would not be needed on the HECO system until 2009. However, in 2003, the Hawaii economy began to bounce back from the post-9/11 concerns, and by the filing of its March 2004 AOS report, HECO estimated that the new generating unit would be needed in 2006, an advance of three years, primarily due to a higher forecast for peak demand. Even though HECO began preliminary engineering work for this project in 2002 and submitted an initial air permit application with the State of Hawaii Department of Health in October 2003, the earliest feasible date for installation of the Campbell Industrial Park combustion turbine remains in 2009. Increased urgency could not shave three years off the project implementation schedule.

HECO has been able to effectively implement a host of mitigation measures to manage -- as best as practicable under the circumstances -- the rapid emergence of the generating reserve capacity shortfall condition. However, such measures have not entirely arrested the reserve capacity shortfall condition as HECO works toward installation of the Campbell Industrial Park combustion turbine in 2009. And while easing of the peak load forecast and moderate EFOR improvement over the past year have reduced the magnitude of the projected reserve capacity shortfall in coming years, the analysis performed for this 2007 AOS indicates that the reserve capacity shortfall –

following the installation of the Campbell Industrial Park combustion turbine – is expected to range from 20 MW to 110 MW in the period 2009 - 2012.

4.4. HECO IRP-3

HECO filed its third major integrated resource plan (IRP-3) on October 28, 2005, and tentatively plans to file an update to its IRP-3 in the May 2007 timeframe. At this time, it is estimated that HECO will file its fourth major IRP (IRP-4) in the June 2008 timeframe.

4.5. Reserve Capacity Shortfalls and Generation Shortfalls

Quantifying the risk of generation-related customer outages is difficult. Many factors cannot be quantified. (See Appendix 5 for a discussion of factors that affect the calculation of reserve capacity shortfalls and factors that affect generation shortfalls).

HECO has sufficient firm generating capacity on its system to meet the forecasted load. HECO may not, at times, have sufficient capacity to cover for the loss of the largest unit or for multiple generating unit outages. For example, on the night of May 31, 2006, a generator owned and operated by Kalaeloa partners was taken off line for emergency maintenance resulting in an unexpected reduction of approximately 118 MW of available generating capacity. At this point, however, HECO still had adequate reserve capacity of approximately 180 MW above the projected peak load to be served the following day. On June 1, 2006, Kalaeloa's second generator tripped offline and two smaller HECO generators subsequently tripped. This caused an imbalance between power demand and supply, creating instability on the island's electric system. HECO turned off power to approximately 37,000 customers in various parts of the island at about 2:12 p.m. to stabilize the electric system, avoid more extensive outages for Oahu customers and prevent damage to the overall system. HECO was able to bring back two of its generators and power was restored to about 17,000 customers around 5 p.m. and to all remaining customers by 6:09 p.m.

Until sufficient capacity can be added to the system, the likelihood of generation-related customer outages exists. The risk of generation-related customer outages is also dependent on the success of implementing various demand-side programs, including the residential and commercial load management DSM programs, the interim and enhanced energy efficiency DSM programs, and the load management program modifications, and the level of customer participation in these programs. In addition, the risk of generation-related customer outages is dependent on the ability of HECO and its IPP partners to maintain the availability of existing generating resources.

Several mitigation measures have been identified to best manage the increased reliability risk brought on by the shortfall in reserve capacity while the process to add a simple-cycle combustion turbine in 2009 continues. However, the interim mitigation measures do not provide the same level of reliability as a large increment of firm capacity and are not designed to be permanent resources.

5. Action Plan and Mitigation Measures

Appendix 4 of the 2006 AOS provided extensive Action Plan and Mitigation Measures, including efforts to (1) pursue accelerated installation of the next generating unit, (2) sustain operational staff to allow for 24 hours a day, 7 days a week operation of all generating units, (3) pursue the staffing plan for night maintenance, (4) continue to reschedule maintenance of generating units when feasible, (5) continue to work with independent power producer partners to increase availability, (6) pursue initiatives that improve EFOR for HECO generating units, (7) evaluate filing of a request to commit funds in excess of \$2.5 million for a 2nd CT at Campbell Industrial Park, (8) evaluate additional DG opportunities, (9) expand peak-shifting strategies, (10) move forward on renewable proposals submitted to HECO and RHI, (11) support sea water air conditioning, (12) implement PV, and (13) prepare for potential outages. A review of these items is presented in Appendix 3.

The 2007 AOS Reference Scenario analysis projects reserve capacity shortfalls in the range of 70 MW until the Campbell Industrial Park combustion turbine can be added in mid-2009. HECO will continue to pursue the Action Plan and Mitigation measures described in the 2006 AOS because the list of activities is comprehensive, and significant new opportunities – over and above those already identified – have not emerged over the last year. HECO remains optimistic that the progress made with regard to the Campbell Industrial Park project over the last year will continue. A description of the 2007 AOS Action Plan and Mitigation Measures is provided in Appendix 4.

6. Conclusion

HECO anticipates reserve capacity shortfalls in 2007 and projects these shortfalls to continue at least until 2009, which is the earliest that HECO expects to be able to permit, acquire, install and place into commercial operation its next central station generating unit.

Approximately 70 MW of additional peak load reduction measures and/or firm generating capacity would be needed in 2007 and 2008 in order to maintain generating system reliability at or above HECO's reliability guideline. This is in addition to (1) the projected successful implementation of the residential and commercial load management DSM programs for which HECO has already obtained approval, and (2) approval for, and successful implementation of, the

Interim DSM Proposals in July 2006 and the enhanced energy efficiency DSM programs and load management program modifications beginning in 2007.

Until sufficient generating capacity can be added to the system, HECO will experience a higher risk of generation-related customer outages, and more frequent, longer duration reserve capacity shortfalls. The actual risk of generation-related customer outages depends, among other factors, on (1) the actual peaks experienced by the system, (2) success in implementing the energy efficiency DSM and load management programs, and customer participation in these programs, (3) the ability of HECO and its IPP partners to minimize unplanned or extended outages of existing generating units, and (4) the extent to which mitigation measures can be implemented. If actual peaks, due to weather impacts or other factors, are higher than forecasted, or if generating units experience higher forced outage rates, and/or more and longer maintenance outages, the risk of generation-related customer outages will increase.

HECO has made progress toward the installation of the combustion turbine at Campbell Industrial Park and is optimistic that this firm capacity can be added to the system by mid-2009. However, HECO also assessed the reserve capacity shortfall under the scenario where the combustion turbine is not installed, in Appendix 6.

Timely installation of the combustion turbine is important to HECO, and efforts are being made to facilitate this project. However, HECO must also address the reserve capacity shortfall that is expected following its installation, and the risk that it will be greater than that in the Reference Scenario. A pronounced reduction in the load forecast (Aug06 for 2007 AOS versus May05 for2006 AOS), continued load-reducing impacts from energy efficiency DSM and load management, moderate EFOR improvement, and the installation of a nominal 110 MW of firm generation, will reduce -- but not eliminate -- the reserve capacity shortfall in the years 2009 - 2012. Further, sensitivity analysis indicates that there are many possible futures, reflecting the uncertainty inherent in projections made for time frames that are three to five years distant (estimates made in 2007 for 2010-2012) . The assessment takes on a much different tone when real possibilities are evaluated, such as higher loads (and/or less load-reducing impacts of energy efficiency DSM and load management), or unit unavailability that is over and above that forecast in the Reference Scenario. The sensitivity results indicate that a variety of conditions could result in a pronounced reserve capacity shortfall.

HECO will continue its portfolio approach to meet its obligation to serve, which includes energy efficiency DSM and load management programs, use of temporary distributed generation as a mitigation measure, use of distributed generation (with more permanent design features) as a long-term resource, and pursuit of central-station supply side options. However, HECO must also recognize that the environment for resource planning has increased in complexity and uncertainty. For example, HECO had previously assumed that significant numbers of CHP systems could be installed on Oahu (in large measure through a HECO CHP program), and its IRP-3 filed in October 2005 anticipated impacts of up to 50 MW in the period 2006 - 2025. .

HECO is not expecting meaningful installations for CHP. HECO must therefore be proactive, anticipating the what-ifs, and cannot bank on the Reference Scenario occurring.

One potential means to address the ever increasing planning uncertainty and complexity is to revise the capacity planning guideline. For example, if the existing Loss of Load Probability of 4.5 years per day does not provide an adequate cushion to respond to quickly-changing assumptions, many of which the utility has little or no sole control over, then the utility could plan for a higher reserve margin. Such an approach would not eliminate quickly-changing assumptions, but it would add a measure of conservatism in recognition that the uncertainties undoubtedly exist. In response to questions raised by the Consumer Advocate in Docket No. 05-0145 (Campbell Industrial Park Generating Station and Transmission Additions Project), HECO has performed a high-level evaluation of the impact of a more stringent reliability guideline in Appendix 8.

Generally, project development times have increased, in part due to new regulatory procedures such as competitive bidding. For example, major discretionary permitting and approval activities for the Campbell Industrial Park project were initiated in 2003. While significant progress has been made to date, the Covered Source Permit and the PUC project approval are critical path items for the project to be placed in service by mid-2009. In the future, the implementation of competitive bidding for new increments of capacity will require additional steps to be completed prior to submitting the PUC application, such as development of an RFP, time for bidders to respond, evaluation of bids, and potential contract negotiation.

As a result, capacity-addition projects will need to be initiated earlier, even when there is less certainty of assumptions further out in the future, in order for HECO to be in a position to meet its obligation to serve when the need for more capacity in fact materializes. It is this growing uncertainty of what the future holds and the increasing time required by processes to add capacity that drives the very need to take affirmative action to pursue new firm capacity additions even sooner. The simple rationale behind this approach is that the risks are not symmetrical. While HECO 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 to accelerate resource plans if unanticipated changes in key drivers demand that firm capacity is needed sooner than anticipated.

For utilities in mainland jurisdictions, short-term power purchases may be available on very short notice, to bridge gaps between existing resources and customer demand. For example, a utility may be able to import additional power quickly in response to unanticipated weather (causing higher than forecast loads) or the catastrophic failure of one of its own generators. HECO does not have access to power markets.

After the planned mid-2009 addition of the Campbell Industrial Park generating unit, and in recognition of the uncertainty underlying key forecasts, HECO anticipates the potential for continued reserve capacity shortfalls which could range between 20 MW to 110 MW in the 2009 to 2012 period. Any plan to install additional firm capacity is required to proceed under the guidance of the Competitive Bidding Framework issued by the Commission on December 8, 2006 in D&O 23121.

Very truly yours,

Attachments

cc: Division of Consumer Advocacy

Table A1:
Projected Reserve Margins with and without Future DSM

		Without Future DSM (Includes Acquired DSM(I))			With Future DSM (Includes Acquired DSM(I))		
Year	System Capability at Annual Peak Load (net kW) [A] (II)	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)
Recorded 2006	1,657,400	1,289,700	17,400	30%	N/A	17,400	N/A
Future 2007	1,673,800	1,294,200	19,500	31%	1,285,800	24,200	33%
2008	1,673,800	1,310,200	19,500	30%	1,293,900	33,200	33%
2009	1,786,800	1,334,200	19,500	36%	1,310,300	40,800	41%

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 2007-2009 include the actual peak reduction benefits acquired in 1996-2005 and also include the peak reduction benefits acquired in 2006 of approximately 5,600 net-kW (net of free riders) by year end.
- Without this 2006 peak reduction benefit, the recorded system net peak of 1,289,700 kW in 2006, which includes 25,000 kW of stand-by load, and 3,200 kW of energy efficiency DSM, would have been 1,292,900 kW.

II. System Capability includes:
- HECO central station units at a total normal capability of 1,208,600 kW-net or 1,263,000 kW-gross.
- Temporary, HECO-sited distributed generating units with a total capability of 14,800 kW-net. An additional 9,800 kW-net of temporary utility-sited distributed generating units were installed in 2006, but were installed after the 2006 system peak and therefore was not included in the 2006 System Capability.

- Firm power purchase contracts have 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 2007-2009 annual forecasted system peaks are based on HECO's August 2006 Sales and Peak Forecast.
- Forecasted system peaks include the peak reducing impacts of future non-utility CHP impacts.
- The peak for 2007 includes 26,000 kW of stand-by load for the following cogenerators:

Tesoro	20.0
Chevron	4.0
Pearl Harbor	2.0
	26.0 MW

  For 2008 and 2009, an additional 2,000 kW is estimated for Chevron's stand-by load. As a result, the total stand-by load beginning in 2008 will be 28,000 kW.
- The HECO annual forecasted system peak is expected to occur in the month of October.

IV. Interruptible Load[18] (Without Future Peak Reduction Benefits of DSM Programs):

- By the end of 2006, HECO had acquired approximately 14,300 kW of Load Management DSM peak reduction benefits from the RDLC and CIDLC Programs. Approximately 12,200 kW of Load Management peak reduction benefits had been acquired by the 2006 system peak.
- Interruptible Load include 5,200 kW of the peak reduction benefits from Rider I customer contracts.

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

- The 2007-2009 annual forecasted system peaks are based on HECO's August 2006 Sales and Peak Forecast.
- The forecasted System Peaks for 2007-2009 include the peak reduction benefits of HECO's energy efficiency DSM programs (acquired and future).
- Forecasted system peaks include the peak reducing impacts of future non-utility CHP impacts.

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[18] The Interruptible Load impacts are at the system level (based on a T&D loss factor of 4.864%) and are coincident with the expected system peak month.

- The peak for 2007 includes 26,000 kW of stand-by load for the following cogenerators:

Tesoro	20.0
Chevron	4.0
Pearl Harbor	2.0
	26.0 MW

  For 2008 and 2009, an additional 2,000 kW is estimated for Chevron's stand-by load. As a result, the total stand-by load beginning in 2008 will be 28,000 kW.
- The HECO annual forecasted system peak is expected to occur in the month of October.

VI. Interruptible Load[19] (With Future Peak Reduction Benefits of DSM Programs):

- Interruptible Load includes 5,200 kW of the peak reduction benefits from Rider I customer contracts.
- Approval for the Residential Direct Load Control program ("RDLC") was obtained in Docket No. 03-0166. Approval for the Commercial & Industrial Direct Load Control ("CIDLC") program was obtained in Docket No. 03-0415. Future peak-reduction benefits incorporate the impact of modifications to the RDLC Program to include residential central air-conditioning load control, approved by the Commission on December 29, 2006, and modifications to the CIDLC Program filed on December 29, 2006, a decision on which is pending at the Commission.

[19] The Interruptible Load impacts are at the system level (based on a T&D loss factor of 4.864%) and are coincident with the expected system peak month.

Appendix 2:

Additional Detail Regarding Relevant Events
Since the March 6, 2006 Adequacy of Supply Report

1. Load Management DSM Programs

As explained in Section 3.4, a combination of factors has led to revisions in the timing of expected load management DSM impacts. Table A2-1 compares the 2006 AOS assumptions for residential and commercial load management DSM impacts with the 2007 AOS assumptions.

Table A2-1:
Previous & Current Projections of Load Management Impacts

Year	RDLC			CIDLC		
	2006 Projections (MW)	2007 Projections (MW)	Difference[20]	2006 Projections (MW)	2007 Projections[21] (MW)	Difference[22]
2006	9	9	0	6	4	-3
2007	13	13	0	9	6	-3
2008	17	16	0	14	12	-3
2009	17	18	0	20	18	-2
2010	17	18	0	25	24	-1
2011	17	18	0	26	27	1
2012	17	18	0	26	27	1

Participation in the Residential Direct Load Control (RDLC), for which approval was obtained in Docket No. 03-0166, continues to be good and expected impacts are consistent with those identified in the 2006 AOS Report. A request by HECO to add residential central air-conditioning load control to the program was approved by the Commission on December 29, 2006, in Decision and Order No. 23181.

The Commercial & Industrial Direct Load Control Program (CIDLC) Programs, for which approval was obtained in Docket No. 03-0415, continues to under-perform compared to original expectations. The lower customer participation in the Commercial & Industrial Direct

[20] Differences may not add due to rounding
[21] 2012 CIDLC impacts in the 2007 AOS were revised to limit the total interruptibles to 50 MW maximum (18 RDLC + 27 CIDLC + 5 Rider I = 50).
[22] Differences may not add due to rounding

Load Control program could result from factors such as the challenges of responding to an immediate load reduction brought about by activation of the under-frequency relay, as currently required. Thus, HECO has found it necessary to adjust the mechanics and promotion of these programs to achieve the planned results. On December 29, 2006, HECO submitted to the Commission and Amendment to the CIDLC Program Application requesting a number of modifications to the program intended to correct this under-performance. Implementation of these modifications will in time lead to greater load reductions in the CIDLC program, but it will not be seen before 2009. The CIDLC Program modifications remain under review by the Commission.

One of the modifications is to offer an option that does not require an under-frequency relay. Another modification is to offer a Voluntary Load Curtailment (VLC) option which provides customers the ability to participate in the program, but with no firm commitment of load. Because the MW impacts obtained from either of these options are may not be available during times of need, they are not quantified for the purposes of deferring supply-side options, but they can enhance system reliability in situations in which short-term generation shortfalls are anticipated. With these options more customers are expected to participate in the program. However, customers who might have participated under the original (more-stringent) CIDLC program may initially choose one of these options instead, which reduces the quantified load management impacts shown in Table A2-1 (through 2010). On the other hand, HECO expects that, with experience under these two options, customers will recognize that they can cope with service interruptions and will switch to the more-stringent CIDLC program options that are quantified for the purposes of deferring supply-side options, in order to receive the higher incentives. As shown in Table A2-1, this is expected to result in increased load management impacts in 2011 and beyond. This estimated migration from less-stringent to more-stringent CIDLC offerings is a forecast of customer choice, and contains elements of uncertainty.

2. Enhanced Energy Efficiency Demand-Side Management (DSM)

On February 13, 2007, in the Energy Efficiency Docket (Docket No. 05-0069) the Commission issued Decision and Order No. 23258, approving HECO's proposed energy efficiency DSM programs, including the RCEA Program. HECO's proposal in the Energy Efficiency Docket consisted of the enhancement of existing DSM programs[23] and the addition of a new program, the Residential Low Income ("RLI") Program. The RCEA Program was proposed by HECO in its 2005 test year rate case, Docket No. 04-0113. The Commission also ordered that the energy efficiency programs transition to a non-utility administrator by January

[23] HECO's existing energy efficiency programs consist of the Commercial and Industrial ("C&I") Energy Efficiency ("CIEE"), C&I New Construction ("CINC"), C&I Customized Rebate ("CICR"), Residential Efficient Water Heating ("REWH"), Residential New Construction ("RNC"), and Interim Energy Solutions for the Home ("ESH") Programs.

2009. The impact of the transition is further discussed below.

Table A2-2 compares the 2006 AOS assumptions for energy efficiency DSM impacts with the 2007 AOS assumptions. The forecast of energy efficiency DSM impacts in the years through 2009 remains approximately the same and reflects a slight lag in the implementation of enhancements to existing programs and the new program requested in the Energy Efficiency Docket. The issuance of D&O No. 23258 on February 13, 2007, is consistent with the lag in the program implementation schedule (i.e., Commission approval of the DSM programs in early 2007 and program implementation in mid-2007) assumed in the 2007 AOS.

The difference between 2006 AOS and 2007 AOS impact projections beyond 2009, however, is primarily due to the treatment of market transformation effects. In the 2006 AOS report, certain energy efficiency measures that were installed as a result of a DSM program were assumed to produce savings beyond the life of the measure because customers would either chose to reinstall the same energy efficient measure instead of the original inefficient device, or because the original inefficient device was simply no longer available due to market transformation. In this 2007 AOS report, it is also assumed that market transformation will lead customers to continue to install certain efficient measures after the useful life of a DSM measure. However, it is assumed that this effect is captured in the peak and sales forecast as part of naturally occurring conservation. This effect would also take into account periodic changes in building codes such as the recent adoption of the model energy code here in Hawaii.

Table A2-2:
Prior & Current Projections of Energy Efficiency DSM

Year	2006 Projections[24] (MW)	2007 Projections (MW)	Difference[25]
2006	4	5	1
2007	13	14	1
2008	23	22	0
2009	32	30	-2
2010	41	37	-3
2011	49	43	-6
2012	58	48	-10

[24] To allow equivalent-basis comparison to 2007 AOS projections, 20006 AOS figures are reduced by 2005 Acquired impacts. The 2006 AOS did not present data for year 2011 and 2012, but it is being included here for comparative purposes.

[25] Differences may not add due to rounding

Even with this change in accounting for market transformation and savings after the end of certain DSM measure service lives, uncertainties associated with obtaining the peak reduction impacts from the energy efficiency DSM programs still exist. These uncertainties include lower customer participation in the programs due to factors such as inadequate awareness about their energy options. If customer participation in these programs is lower than estimated, impacts from these DSM programs will be delayed and will be lower than estimated, ultimately resulting in higher peak loads.

Prior to the recent approval of HECO's DSM energy efficiency programs on February 13, 2007, HECO had attempted to accelerate the enhanced DSM programs as much as it could, while still complying with mandated regulatory and planning processes. The programs were developed in the on-going IRP-3 process. The entire process of developing the changes to HECO's portfolio of programs began in 2003 with the initiation of a DSM potential study in July 2003 and the organization of a DSM Technical Committee under IRP auspices in December 2003. The DSM Technical Committee provided valuable input into the design of the DSM programs. The last meeting of the Committee was held on April 21, 2004 and culminated in the portfolio of 10 DSM programs (including the two load management programs). They were fully documented and filed with HECO's rate case filed in November 2004, as required by HECO's Commission-approved stipulations with the Consumer Advocate (for the C&I DSM programs) and with the Consumer Advocate and other parties (for the Residential DSM programs). The Commission must approve the modifications to these existing programs and the new DSM programs before the modifications and new programs are implemented. Prior to 2005, HECO also had taken steps to accelerate the acquisition of demand reductions through its energy efficiency programs existing at the time (REWH, RNC, CIEE, CINC, and CICR), as explained in the response to CA-IR-567 in Docket No. 04-0113.

By Order 21698, issued March 16, 2005, the Commission separated HECO's request for approval and/or modification of demand-side and load management programs and recovery of program costs and DSM utility incentives (the "Proposed DSM Programs") from the Rate Case Docket, and opened Docket No. 05-0069 (the "Energy Efficiency Docket").

Since the bifurcation did not result in an accelerated schedule for the complete DSM proposal, HECO proposed a schedule that would permit it to submit the Interim DSM proposals. Following HECO's informal submission of its Interim DSM Program modifications to the parties on October 11, 2005, HECO filed a letter with the Commission on December 5, 2005 requesting modifications to HECO's existing energy efficiency programs and also approval of a new interim DSM program, collectively referred to as HECO's "Interim DSM Proposals". The "Interim DSM Proposal" was approved by the Commission on April 26, 2006 in Decision and Order No. 22420. The approval and implementation of the Interim DSM Proposal has already resulted in increased peak reduction benefits in 2006, as can be seen in Table A2-2 above. The Commission approved HECO's proposed energy efficiency DSM programs on February 13, 2007.

Along with its approval of the portfolio of energy efficiency DSM programs in D&O No. 23258, the Commission also ordered that the programs transition to a non-utility administrator by January 2009[26]. The Commission intends to open another docket to examine the selection of the non-utility administrator and refine the details of the new market structure. It is HECO's intention to assist in the transition in order that it occurs as smoothly as possible. Thus, while HECO's estimate of energy efficiency program impacts was developed under the assumption that HECO was the program administrator throughout the AOS report horizon, the Company has not made any adjustments to the projections as the result of the Commission's order. Still, in HECO's Opening Brief in Docket No. 05-0069 at page 167, HECO pointed out that during a period of transition, duplicate costs may be unavoidable and delays in the acquisition of DSM impacts, which HECO depends on to meet a substantial portion of its future capacity needs, could occur.

3. Distributed Generation and Combined Heat and Power (CHP)

Firm DG resources can provide generating capacity if dispatchable by the utility, or can reduce peak loads if operated by customers. HECO has been including forecasted firm DG resources, namely CHP, in its Adequacy of Supply ("AOS") evaluations for the past few years. HECO is also evaluating other firm DG resource opportunities besides CHP, as described in Appendix 3. The updated short-term CHP forecast (dated July 27, 2006) used for this 2007 AOS report projects that the peak reduction impacts of CHP installations will be lower than the impacts projected for the 2006 AOS report.[27] This comes as a result of (1) new rules issued by the U.S. Environmental Protection Agency ("EPA") which will require more stringent emission controls for stationary diesel engines in the near future, (2) limitations as to the ability of HECO to provide customer-sited DG projects on a regulated utility basis, and (3) other uncertainties concerning customer-sited DG.

New EPA Requirements

On July 11, 2005, the EPA issued interim New Source Performance Standards ("NSPS") requiring lower nitrogen oxides ("NOx") emission levels for stationary diesel engines manufactured after April 1, 2006. On July 11, 2006 the EPA issued the final NSPS for stationary diesel engines, specifying the lower NOx emission requirements to take effect in January 2011. The NSPS also requires the use of lower sulfur diesel fuel, with the most stringent requirements

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[26] The Commission also ordered that load management programs (e.g., RDLC and CIDLC Programs) remain under utility administration.

[27] For example, in the 2006 AOS report, the peak reduction impact of CHP in the year 2008 was forecasted to be 4 MW. In this 2007 AOS report, the peak reduction impact of CHP in the year 2008 is forecast to be 1 MW.

taking effect in late 2010 for units built after April 1, 2006. Based on HECO's understanding, the new NSPS could significantly increase the costs of future DG installations. This would especially impact the feasibility of future customer DG installations, including CHP.

Limitations on Utility DG at Customer Sites

In October 2003, the PUC opened a DG Investigative Docket No. 03-0371 to determine DG's potential benefits to and impact on Hawaii's electric distribution systems and markets and to develop policies and a framework for DG projects deployed in Hawaii.

On January 27, 2006, the Commission issued Decision and Order No. 22248 ("D&O 22248") in its DG Investigative Docket. In D&O 22248, the PUC indicated that its policy is to promote the development of a market structure that assures DG is available at the lowest feasible cost, DG that is economical and reliable has an opportunity to come to fruition and DG that is not cost-effective does not enter the system. To help ensure that only cost-effective DG is installed by customers, the Commission determined that other customers should not be required to subsidize those who install DG. Thus, D&O 22248 requires that costs incurred by the electric utilities to accommodate DG, including costs of interconnection and of providing standby and backup services, should be borne by the DG customer.

With regard to DG ownership, D&O 22248 affirmed the ability of the electric utilities to procure and operate DG for utility purposes at utility sites. The PUC also indicated its desire to promote the development of a competitive market for customer-sited DG. In weighing the general advantages and disadvantages of allowing a utility to provide DG services on a customer's site, the PUC found that the "disadvantages outweigh the advantages." However, the PUC also found that the utility "is the most informed potential provider of DG" and it would not be in the public interest to exclude the electric utilities from providing DG services at this early stage of DG market development.

Therefore, D&O 22248 allows the utility to provide DG services on a customer-owned site as a regulated service when (1) the DG resolves a legitimate system need, (2) the DG is the lowest cost alternative to meet that need, and (3) it can be shown that, in an open and competitive process acceptable to the PUC, the customer operator was unable to find another entity ready and able to supply the proposed DG service at a price and quality comparable to the utility's offering.

On March 1, 2006, HECO (along with HELCO and MECO, collectively, the "Companies") filed a Motion for Clarification and/or Partial Reconsideration ("DG Motion"), requesting that the PUC clarify how the three conditions under which electric utilities are allowed to provide regulated DG services at customer-owned sites will be administered, in order to better determine the impacts the conditions may have on the Companies' DG plans. On April 6, 2006, the PUC issued Order No. 22375 on the DG Motion and provided clarification to the conditions under which electric utilities are allowed to provide regulated DG services (e.g., utilities can use a portfolio perspective—a DG project aggregated with other DG systems and other supply-side and demand-side options—to support a finding that utility-owned customer-sited DG projects fulfill a legitimate system need, and the economic standard of "least cost" in the order means "lowest reasonable cost" consistent with the standard in the IRP framework), and affirmed that the electric utility has the responsibility to demonstrate that it meets all applicable criteria included in D&O 22248 in its application for PUC approval to proceed with a specific DG project.

Prior to opening of the investigative DG proceeding, in October 2003 the Companies filed an application for approval of CHP tariffs, under which they would own, operate and maintain customer-sited, packaged CHP systems (and certain ancillary equipment) pursuant to standard form contracts with eligible commercial customers. This CHP tariff application, considered in Docket No. 03-0366, was suspended by the PUC in March 2004 until, at a minimum, the matters in Docket No. 03-0371 were adequately addressed.

By letter dated November 2, 2006, the PUC requested that the Companies state their intentions with regard to pursuing the CHP tariff application, given the PUC criteria for allowing regulated utility-owned DG stated in D&O 22248, as clarified by Order No. 22375. On December 29, 2006, the Companies withdrew their CHP tariff application, based on the determination that it would be difficult to implement CHP projects on a programmatic basis given the criteria of D&O 22248, as clarified. The Companies will continue to consider CHP projects on a case-by-case basis, and if a decision is made to pursue the implementation of a CHP project, then an application would be filed requesting PUC approval of such CHP project.

D&O 22248 also required the Companies to file tariffs, establish reliability and safety requirements for DG, establish a non-discriminatory DG interconnection policy, develop a standardized interconnection agreement to streamline the DG application review process, establish standby rates based on unbundled costs associated with providing each service (i.e., generation, distribution, transmission and ancillary services), and establish detailed affiliate requirements should the utility choose to sell DG through an affiliate. The Companies filed their proposed modifications to existing DG interconnection tariffs and their proposed unbundled standby rates for PUC approval in the third quarter of 2006. By Order No. 23171, dated December 28, 2006, the PUC opened a new proceeding, Docket No. 2006-0497, to investigate the Companies' proposed DG interconnection tariff modifications and standby rate tariffs. The PUC has scheduled public hearings beginning in February 2007.

<u>Other Uncertainties Associated with Customer DG</u>

There is a significant degree of uncertainty in forecasting the customer DG market. On a macro-scale, the economic viability of CHP is highly sensitive to fuel and electricity prices. The energy efficiency benefits of a CHP system may not translate to overall cost savings for a customer if the CHP fuel cost (for diesel fuel oil, propane or synthetic natural gas) is significantly higher than the cost of fuel used to generate grid electricity. Furthermore, prospective CHP projects are subject to customer desire and support, which can be extremely variable. Also site-specific factors add uncertainty, as they may affect the feasibility of moving forward with a project even when the desire for CHP is strong. Finally, it should be noted that until Docket No. 2006-0497 is completed, the impacts, if any, of new DG interconnection and standby rate tariffs on customer DG development will be difficult to determine.

Based on the above events and uncertainties, a revised 20-year forecast for CHP was developed that reflects that CHP penetration is expected to be more limited compared to previous forecasts. No new CHP systems were commissioned on Oahu in 2006. HECO had anticipated one non-utility CHP system to be placed in service in 2006, but now expects that system to be started up in 2007. No HECO CHP is forecasted.

Appendix 3:

Review of 2006 AOS Action Plan and Mitigation Measures

The 2006 AOS described Action Plan and Mitigation Measures that HECO would employ in order to provide reliable service (refer to Section II.5, pages 37-38). HECO's action plan and mitigation measures are not intended to be a single plan of action. Instead, HECO's action plan and mitigation measures are meant to be part of a process to continuously re-evaluate, re-assess, and modify the appropriate actions and measures that should be planned for in response to changing circumstances. This Appendix reviews the status of these items.

Action Plan

1. Pursue Accelerated Installation of Next Generating Unit

Status: On-going

This project is still in the Permits and Approvals stage. The Covered Source Permit and the PUC approval are the critical path items for this part of the project.

The Hawaii Department of Health (DoH) issued a draft permit for public comment and held a public hearing in December 2006 and is currently addressing the comments that were received. Once responses to the comments are finalized, the next step is for the DoH to forward the draft permit, comments, and responses to the Environmental Protection Agency for review. The schedule for this permit is currently controlled by these two agencies and there is little, if anything, that HECO can do at this point to accelerate the process.

All the deadlines for testimonies, information requests, and responses were met by HECO and the other parties involved in the project docket, culminating in an evidentiary hearing in December 2006 as originally scheduled. Opening briefs are due on March 2, 2007 and Reply Briefs will be due on March 16, 2007. Following submittal of these briefs, the only remaining step is for the Commission to issue a Decision and Order.

2. Sustain Operational Staff to Allow for 24 hours a day, 7 days a week Operation of all Generating Units.

Status: On-going

To meet generation system demands, additional staffing was added at Waiau units 3 and 4 and Honolulu 8 and 9 to return those units to 24/7 operation beginning March 21, 2005 and June 27, 2005, respectively. When HECO does not have a full complement of qualified operators the only alternative is to rely on the existing operators to work overtime. Accordingly, a high priority has been placed on hiring and training of new operators to fill vacancies in the work force.

Over the past few years in the labor market in Hawaii, it has become increasingly difficult to attract and retain qualified employees as statewide unemployment rates have decreased. HECO has continued its professional approach to attract, qualify, hire and retain qualified employees. To address the needs of the more difficult employment market, however, HECO has expanded its efforts in several ways to meet the need to fill the vacancies in the Power Supply Process Area, including:

- Increased the number of dedicated Workforce Staffing and Development (WSD) consultants from one to two and a half people,
- Increased the number of Operator Trainee (entry position) classes from 2 times per year to 4 times per year,
- Organized and conducted the first HECO Power Supply Job Fair at the Waiau Power Plant on September 30, 2006,
- Increased participation with U.S. Military job fairs and placement consultants,
- Increased job advertisements and active recruitment for mainland candidates,
- Increased coordination with Hawaii's community colleges, including possible development of a technical curriculum at Leeward Community College,
- Increased the use of the internet for attracting and processing applications,
- Reassessing the implementation of a HECO-specific apprentice program for selected trades and crafts.

In spite of these difficulties, HECO continues to maintain sufficient staffing levels to sustain 24/7 operation of all generating units.

3. Pursue Staffing Plan for Night Maintenance

Status: "Night Maintenance" strategy has been revised

Since March 2006, based -- in part -- on the EPRI Solutions Inc. review of HECO's Power Supply operations, maintenance, and outage management programs, HECO has concluded it can more effectively perform all the required maintenance, day and night, by bolstering its existing Station and Travel Maintenance Crews instead of creating a new night maintenance crew. Thus, the 20 maintenance positions that had been assigned to the night maintenance have been re-allocated among the existing Travel and Station Maintenance Crews. Any and all maintenance personnel will be scheduled to work night shifts as necessary to perform critical station and overhaul work.

As stated in the 2006 AOS, "Planned outages and maintenance outages also reduce generating unit availabilities." Bolstering the existing Travel and Station Maintenance Crews will also enable consideration of working more hours per day (i.e., multiple crews) on critical path activities during overhauls. Accordingly, durations of planned and maintenance outages are expected to be shorter in the future with a full complement of maintenance personnel.

4. Continue to Reschedule Maintenance of Generating Units when Feasible

Status: On-going

The flexibility HECO has in rearranging the generating unit maintenance schedule decreases as reserve capacity decreases. However, current assessments of generating unit and system conditions (e.g., anticipated load) are used to adjust maintenance schedules, when feasible.

5. Continue to Work with IPP Partners to Increase Availability

Status: On-going

The firm capacity IPPs provide a substantial portion of HECO's energy and capacity. Thus, it is important that these IPPs have high availability. As an example, HECO is continuing to work with Kalaeloa to encourage and monitor their efforts to pursue both short term and long term solutions to the various root causes of the ongoing HRSG leak issues. In the 2007 scheduled maintenance inspection for CT2, Kalaeloa will replace tube bundles in the High Pressure/Low

Temperature (HP/LT) section of the HRSG and remove, inspect, clean and return to service tube bundles in the High Pressure/High Temperature (HP/HT) economizer. These two areas have been the primary sections where the leaks have occurred. A similar protocol is planned for the CT1 scheduled maintenance inspection in 2008. Both HECO and Kalaeloa anticipate that the leak issues with the HRSG's are technically challenging and will need diligent efforts going forward to avoid a notable deterioration in Kalaeloa plant availability and performance. In some cases the additional work scope during the Kalaeloa scheduled outages as well as the repair work during leak events has necessitated flexibility in making changes to other scheduled outage events on the HECO system. This flexibility is required of HECO units, other IPPs, as well as Kalaeloa.

6. Evaluate Opportunities for Purchase of Additional Firm Capacity and Energy

Status: On-going

No firm IPP capacity has been added since the 2006 AOS. Although there have been expressions of interest from IPP developers, no firm capacity IPP proposals were received in 2006. HECO is aware of the City & County of Honolulu's request for proposals for processing additional municipal waste and producing electrical energy. HECO will enter into negotiations for a power purchase contract with the successful bidder to the request for proposals. When a firm capacity IPP proposal is received, HECO will take into consideration the full scope of all relevant issues, which includes among others maintaining or improving the reliability of Oahu's isolated electrical system, avoiding potential impacts arising from purchased power that may be detrimental to the financial integrity of the utility, impacts to the environment and neighboring communities, and the cost impact to ratepayers. Such factors were considered in the recent success found in the contracting for an additional 28 MW of firm capacity and energy from Kalaeloa Partners, L.P., which was approved by the Commission on May 13, 2005. The full set of benefits and obligations of PPA Amendments No. 5 and No. 6 became effective on September 28, 2005.

It should be noted that the time to add firm capacity in Hawaii is typically substantial, due to the time required to do air permitting, the need for an EA or EIS for fossil-fired generation greater than 5 MW, the need for land use permits and approvals at many sites, and the time required for other regulatory approval proceedings. (HECO does not have the option of "importing" power from other jurisdictions.)

HECO has also engaged in substantive discussions with AES Hawaii regarding its desired sale to HECO of up to 9 MW of additional firm capacity and/or energy. As was the case with the recent Kalaeloa PPA Amendments, any modification to the current power purchase arrangement with AES Hawaii will require an amendment to the existing AES Hawaii PPA and related Commission approval. Any amendment to the PPA, however, will trigger a review under accounting standards EITF No. 01-8 and SFAS No. 13, as to capital lease treatment of the supply arrangement. With regard to the AES proposal, HECO remains concerned with the negative impact to HECO and its ratepayers of treating the AES Hawaii PPA as a capital lease. HECO also remains concerned that a PPA amendment might trigger the consolidation of AES Hawaii on HECO's books under another accounting standard, FIN 46R. Moreover, HECO's spinning reserve and quick load pickup (QLPU) requirements are based on AES Hawaii's committed capacity of 180 MW, the largest single electrical generator on the HECO system. Any increase in AES Hawaii's output above 180 MW would impact HECO spinning reserve and QLPU requirements, and the resulting system operational and reliability impacts, as well as the increase in costs to customers has to be considered.

These substantial hurdles must be overcome before any amendment of the AES Hawaii PPA to purchase up to 9 MW of additional firm capacity and/or energy could prove to be in the public interest and just and reasonable from the ratepayer perspective. HECO must take all cost impacts into account, including those arising out of new accounting standards and/or interpretations. Nonetheless, HECO remains interested in purchasing additional capacity and/or energy from AES Hawaii if the financial, operational and contractual issues can be addressed. Unfortunately, at this time, that does not appear to be the case.

7. Pursue Initiatives that Improve the EFOR of HECO Generating Units

Status: On-going

Unplanned deratings and/or unit trips are difficult to predict, and are related to how hard HECO's aging units are operated, and the amount of reserve margin available to perform repairs while minimizing risk to the system. When problems are detected, corrective action is taken as soon as possible once the root cause is identified. In the case of unplanned deratings, corrective action may be delayed depending on expected system demand, available reserve margin, outage priorities on other units, and parts/materials availability.

HECO's 2006 EFOR performance of 5.3% is better than the 6.8% forecast in the 2006 AOS and represents a turnaround from the higher level experienced in 2005. Restoring the reserve margin by adding generation (as addressed in Docket No. 05-0145) and managing load (as addressed in the Energy Efficiency and Load Management dockets) will help improve the EFOR of HECO generating units, by providing HECO with more flexibility to schedule and perform maintenance on our aging generation assets. Just as importantly, HECO needs to be able to carry out its staffing and training plans so the staffing assets necessary are in place to effectively perform reliability programs and initiatives.

8. Evaluate Filing of Request to Commit Funds in Excess of \$2.5 million for 2nd CT at Campbell Industrial Park Site

Status: On-going

After the planned mid-2009 addition of the Campbell Industrial Park generating unit, and in recognition of the uncertainty underlying key forecasts, HECO anticipates the potential for continued reserve capacity shortfalls which could range between 20 MW to 110 MW in the 2009 to 2012 period. Any plan to install additional firm capacity is required to proceed under the guidance of the Competitive Bidding Framework issued by the Commission on December 8, 2006 in D&O 23121.

Mitigation Measures

1. Evaluate Additional DG Opportunities

Status: On-going

HECO installed 14.8 MW of temporary, leased DG capacity in 2005 at three HECO sites. In 2006, 9.8 MW of additional DG was added at two HECO sites. Construction work is in progress to add 4.9 MW more near the end of the first quarter of 2007, at which time there will be approximately 29.5 MW of temporary HECO-sited DG in operation. HECO's ability to install DG at additional company sites is limited, primarily due to technical, zoning, and space considerations.

Dispatchable Standby Generation[28]

HECO is pursuing development of dispatchable standby generation ("DSG"), wherein the utility, by contractual arrangement subject to Commission approval, is allowed to dispatch customer-owned standby generators in parallel to the HECO grid, in order to provide supplemental utility generating capacity. DSG customers would be required to execute a DSG agreement as well as an interconnection agreement, and modify their operating permits and facilities as necessary to comport with HECO's requirements to be considered firm dispatchable capacity. HECO has not executed any DSG agreements, although it is in active discussions with two potential DSG customers, the State of Hawaii Department of Transportation Airports Division ("DOT Airports") and a commercial customer on Oahu.

Department of Defense ("DOD") DG Evaluation[28]

HECO conducted a high level assessment and identified a limited number of potentially viable DG sites on Oahu military bases, based on space, location relative to HECO T&D infrastructure, and compatibility with DOD operations. HECO is evaluating the basis on which it could develop long-term HECO-owned DG at military sites to serve HECO grid purposes, while meeting DOD objectives and PUC requirements. The potential for actual DG development on DOD sites and its timing is unknown.

2. Expand Peak-Shifting Strategies

Status: On-going

HECO's rate proposals in the HECO 2007 test year rate case (and its similar rate proposals in HECO's 2005 test year rate case) will provide a time-of-use rate schedule for each of its customer classes (except for Schedule F, Street and Playground Lighting customers, which do not have significant flexibility to shift load). Should all of the proposed voluntary time-based rates be approved, the portfolio of time-of-use rates will include: TOU-R (Residential Time-of-Use Service), TOU-C (Commercial Time-of-Use Service), Rider T (Time-of-Day Rider), Rider M (Off-Peak and Curtailable Service), and Schedule U (Time-of-Use Service).

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28 For consistency with their classification in the 2006 AOS Action Plan, these items are listed under the "Mitigation Measures" in this Appendix 3. However, assuming these facilities can be designed and permitted accordingly, they will be treated as Action Items for this 2007 AOS (as opposed to temporary mitigation measures).

3. Move Forward on Renewable Proposals Submitted to HECO and RHI

Status: On-going

Two rounds of renewable energy requests for project proposals (RE RFPP) for the islands of Oahu, Maui, Molokai, Lanai, and the Big Island of Hawaii were issued between 2003 and 2005. Nearly thirty proposals were received in response to the RE RFPPs. RHI is in discussions with a number of developers for potential renewable energy projects on three different islands. Whether or not these projects are viable will depend on numerous factors, such as cost of the projects, continued availability of tax credits, technical feasibility, and developers' abilities to obtain sites, permits, project financing and/or community support. Renewable Hawaii is providing early stage project development support for selected projects on Oahu.

4. Support Sea Water Air Conditioning

Status: On-going

HECO supports efforts to establish a SWAC system on Oahu. In fact, HECO has offered its headquarters building located at 900 Richards Street as a potential site for the system. The SWAC project has the potential to provide significant levels of renewable energy on Oahu to help meet the State's RPS. HECO also believes that sea water air-conditioning, if shown to be cost effective, should be eligible for DSM program rebates under HECO's CICR Program.

The CICR Program was designed to encompass the installation of energy efficient equipment not specifically identified in any of the other prescriptive DSM programs. These include DSM measures that are not widely available in the market and where HECO does not have previous experience documenting the measure savings. The CICR Program applications typically require pre-monitoring of a facility prior to the installation of the energy efficiency measure, and post-monitoring after the device has been installed and is operational.

The CICR Program also has provisions that require an independent third party review the proposed project if the rebate is projected to be greater than $25,000. This provision enhances the validity of impact results from more complicated projects.

In the Energy Efficiency Docket D&O No. 23258, the Commission ordered that rebates for a SWAC system on Oahu be paid through the CICR Program rather than through the CIEE Program.

5. Implement PV

Status: On-going

Photovoltaic ("PV") systems do not meet firm capacity needs, but do provide energy and value to the utility in terms of meeting renewable portfolio standards requirements. HECO has evaluated development of PV at HECO's Ward Avenue facility. Based on its findings, HECO is currently developing a request for proposals for installation and operation of an approximate 155 kW (dc) PV system to be installed on the rooftop of the Archer Substation. HECO would purchase the energy from the PV system developer. HECO determined that this arrangement enables the most cost-effective development of PV, given the availability of federal renewable energy investment tax credits to non-utility parties. The timing of the installation is forecast as December 2007, but will depend on the acquisition of required permits and regulatory approvals.

Recent developments at the federal level may contribute to increased installations of PV systems by HECO's customers. The federal government recently increased the tax credit incentives for PV systems. Beginning January 1, 2006, the federal tax credit for commercial PV systems increased from 10% to 30% and there is a new 30% credit up to $2,000 for residential PV systems. The 30% federal tax credit expiration was recently extended by one year to December 31, 2008, after which it would revert back to 10%. While State tax credits for PV systems so far remain unchanged, the changes in federal incentives may stimulate market response to PV systems. HECO anticipates that some customers may install PV systems during the forecast period, however the amount and timing of such installations is indeterminate.

As for utility involvement in customer-sited PV, initial development and ownership of PV systems is generally not cost-effective for the electric utility, since regulated electric utilities are not eligible for federal renewable energy investment tax credits.

6. Preparations for Potential Outages

Status: On-going

HECO created a public notification program to establish a process for informing and preparing customers for potential generation-related customer outages and to ask for voluntary conservation when a system emergency occurs in which HECO anticipates that it may not be able to meet the demand for a certain period of the day. The public notification program is a tiered process of notifying the Commission, critical federal, state and local agencies, large commercial customers and the general public depending on the various generating conditions. The worse the generating condition, the broader the notification and requests for conservation.

In 2006 and thus far in 2007, HECO has used the public notification program to ask for help through energy conservation on three occasions: January 10, 2006; June 1 & 2, 2006; and February 1, 2007.

Appendix 4:

Description of 2007 AOS Action Plan and Mitigation Measures

HECO's action plan and mitigation measures are not intended to be a single plan of action. Instead, HECO's action plans and mitigation measures are meant to be part of a process to continuously re-evaluate, re-assess, and modify the appropriate actions and measures that should be planned for in response to changing circumstances.

The 2007 AOS action plan and mitigation measures mirror those described in the 2006 AOS. Generally speaking, the list of activities provided in the 2006 AOS was comprehensive, and HECO does not believe that significant new opportunities – over and above those already identified – have emerged in the last 12 months or so. Appendix 3 provides an updated status for the 2006 AOS action plan and mitigation measures.

Action Plan

1. Pursue Accelerated Installation of Next Generating Unit

Given the critical nature of HECO's reserve capacity shortfall, all efforts are being made to pursue practical opportunities to accelerate the installation of the next generating unit. HECO has already incorporated efforts to expedite the unit installation, and therefore, opportunities to compress the schedule even further are limited. HECO remains optimistic that the progress made with regard to the Campbell Industrial Park project over the last year will continue (Refer to Appendix 3).

2. Implement Enhancements to Existing DSM Programs and New Programs Approved by the Commission

With the approval of HECO's proposed enhancements and new programs on February 13, 2007, HECO has already begun developing program infrastructure and marketing materials in order to implement the changes as quickly as possible.

3. Sustain Operational Staff to Allow for 24 hours a day, 7 days a week Operation of all Generating Units.

Refer to Appendix 3 for a description of HECO's on-going efforts.

4. Continue to Reschedule Maintenance of Generating Units when Feasible

Refer to Appendix 3 for a description of HECO's on-going efforts.

5. Continue to Work with IPP Partners to Increase Availability

Refer to Appendix 3 for a description of HECO's on-going efforts.

6. Evaluate Opportunities for Purchase of Additional Firm Capacity and Energy

HECO continues to explore opportunities to purchase additional firm capacity and energy from independent power producers, taking into consideration the full scope of all relevant issues, which includes among others maintaining or improving the reliability of Oahu's isolated electrical system, avoiding potential impacts arising from purchased power that may be detrimental to the financial integrity of the utility, impacts to the environment and neighboring communities, and the cost impact to ratepayers (refer to Appendix 3).

7. Pursue Initiatives that Improve the EFOR of HECO Generating Units

A discussion of HECO generating unit EFOR is provided in Appendix 7. Included in this discussion are actions that HECO has taken or identified in effort to improve the EFOR rate of its generating units.

8. Evaluate options for pursuing additional firm capacity

Any plan to install additional firm capacity is required to proceed under the guidance of the Competitive Bidding Framework issued by the Commission on December 8, 2006 in D&O 23121.

9. Evaluate Long-Term Distributed Generation Resource Opportunities[29]

HECO will continue to evaluate opportunities to secure long-term, firm, distributed generation resources. Please refer to Appendix 3 for a description of HECO's efforts to evaluate dispatchable standby generation and distributed generation opportunities at Oahu military bases.

[29] Assuming these facilities can be designed and permitted accordingly, they will be treated as Action Items for this 2007 AOS (as opposed to temporary mitigation measures).

Mitigation Measures

1. Evaluate Additional Temporary DG Mitigation Opportunities

HECO has been using temporary DG to mitigate the effects of the reserve capacity shortfall. Please refer to Appendix 3 for a status update and updated outlook for DG.

2. Expand Peak-Shifting Strategies

While actual generation shortfall incidents are not restricted to peak load conditions, reducing the system peak by shifting a portion of the load will generally improve system reliability, everything else being equal. Please refer to Appendix 3 for a description of the rate proposals made in HECO 2007 and 2005 test year rate cases.

3. Move Forward on Renewable Proposals Submitted to HECO and RHI

Renewable Hawaii, Inc. ("RHI"), a non-regulated subsidiary of HECO. Please refer to Appendix 3 for a description of recent RHI activity.

4. Support Sea Water Air Conditioning

Seawater Air Conditioning (SWAC) is a renewable energy technology that is emerging as a possible energy option for reducing the electricity requirement for air conditioning for commercial customers. Please refer to Appendix 3 for a description of recent activity in this area.

5. Implement PV

Photovoltaic ("PV") systems do not meet firm capacity needs, but do provide energy and value to the utility in terms of meeting renewable portfolio standards requirements. Please refer to Appendix 3 for an updated status regarding PV implementation.

6. Preparations for Potential Outages

Please refer to Appendix 3 for information on HECO's public notification program.

Appendix 5:

Uncertainties in HECO Capacity Planning

Any planning activity relies on certain assumptions. For example, when individuals plan for retirement, they may forecast future revenues, expenses, length of retirement, and many other items. Each of these planning assumptions contains an element of uncertainty. Similarly, when HECO performs its capacity planning, it employs assumptions about the future that may turn out to be different from actual results. Described below are some of the key uncertainties related to HECO's capacity planning.

Actual Daily Load versus Forecasted Loads

As mentioned in Section 3, factors such as the schedule for implementing large commercial and residential development projects, the time of year, weather variables (such as rainfall, cloud cover, humidity, winds, and temperature) and their load impacts, and changes in residential and commercial use affect the actual daily load.

HECO does not forecast its load to be an "upper bound" of what future loads could be. HECO's actual load may be higher than the forecasted load.

Non Dispatchable As-available Energy

Resources in this category include the energy provided under as-available energy contracts, such as those between HECO and the Tesoro and Chevron refineries. A key characteristic of non-dispatchable as-available resources is their unpredictable variability. Because energy providers are not under contract to provide specific amounts of capacity or energy at scheduled times, the amount of capacity they will provide at a given time cannot be quantified.

Because a portion of Tesoro, Chevron and Pearl Harbor's load is served by their as-available generators at the time of the system peak and because HECO would need to serve that load had their generators not been running, HECO includes this additional load in its peaks for capacity planning purposes.

Actual Energy Efficiency DSM Impacts versus Forecasted Impacts

There are risks that the Company's enhanced energy efficiency DSM programs will not achieve projected peak load reductions. Those risks include lower customer participation in the programs due to factors such as inadequate awareness about their energy options. If customer participation in these programs is lower than estimated, impacts from these DSM programs will be lower than estimated, ultimately resulting in higher peak loads.

Decision and Order No. 23258 filed February 13, 2007 in Docket No. 05-0069 stated that "All of the HECO Companies' Energy Efficiency DSM programs shall transition from the HECO Companies to the Non-Utility Market Structure, by January 2009, unless otherwise ordered by the commission. The HECO Companies' Load Management programs shall be excluded from the third-party administrator's area of responsibility." HECO has not quantified the potential impact of this D&O on the forecast for energy efficiency in the years beyond 2009, however, transition to a third-party administrator in 2009 creates uncertainty in the assumed energy efficiency peak-reduction impacts.

Actual Load Management DSM Impacts versus Forecasted Impacts:

There are risks that the Company's load management DSM programs will not achieve projected peak load reductions. There is a risk of lower customer participation in the Residential Direct Load Control program due to factors such as inadequate awareness. Lower customer participation in the Commercial & Industrial Direct Load Control program could be due to factors such as the challenges of responding to an immediate load reduction brought about by activation of the under-frequency relay, as currently required.

Actual Outage Schedule versus Forecasted Schedule

Maintenance scheduling is performed by the HECO Power Supply Operations and Maintenance Department. Maintenance scheduling can be expected to change several times over the year because of operational factors. Each year, a five-year schedule is developed to plan for generating unit outages required to complete necessary maintenance, overhauls, inspections, and capital project installations. Throughout the year, as equipment components fail such that corrective maintenance needs to be performed, additional maintenance or repair beyond what was originally planned is required, resulting in the need to revise and update outage schedules. However, revisions to the schedule are limited by constraints in manpower availability to perform the repair work, material and replacement equipment fabrication and delivery lead times, regulatory constraints which require periodic inspections within a set timeframe, and the need to have enough generation available to meet the expected load. Depending on the magnitude and timing of the additional outages required, changes in the outage schedule may result in higher risk to the system by having less than desired generation reserves available to meet HECO's spinning reserve and quick load pickup needs or to keep the LOLP above the 4.5 years per day reliability guideline. In the event planned capacity is delayed, rearranging maintenance schedules should be considered as a measure to mitigate the effects of delays in installing generation or acquiring the peak reduction benefits of energy efficiency DSM, load management DSM or CHP. However, deferring maintenance or rearranging maintenance schedules cannot avoid or permanently defer the need for additional generation under a reserve capacity shortfall situation and, despite short-term benefits, may over time increase generating unit EFOR with a resulting decrease in generation system reliability in the long run. Please refer to HECO's response to CA-IR-42 in the Rate Case Docket No. 04-0113, for an example of how the actual maintenance schedule can be substantially different from the planned maintenance schedule.

Assumed EFOR

Even with timely and prudent maintenance practices, all generating units are subject to forced outages. There is also a risk of multiple forced outages on a given day. Statistical or stochastic analysis may be appropriate for longer-term analyses; however, on a day-to-day basis, forecasting whether or not forced outages are likely to occur is very difficult to quantify.

EFOR is an indication of the probability that a generating unit will be unexpectedly forced out of service due to an unforeseen problem with the unit. Projections of EFOR for each unit are based on factors such as the historical EFOR of the unit and maintenance work that was recently done or will be done to improve the expected reliability of the unit.

A discussion of HECO generating unit EFOR is provided in Appendix 7. Included in this discussion are actions that HECO will take in effort to improve the EFOR rate of its generating units.

Appendix 6:

Additional Sensitivity Analysis of Alternate Scenarios

Section 4.3.2 provides the basic information regarding alternate scenarios to the reference case. Additional quantifiable results for these scenarios are provided in this Appendix. Explanations for HECO's generating system reliability guideline, Rule 1 and Rule 2 planning criteria can be found in Sections 4.2 and 4.1, respectively.

1. Alternate Higher Load Scenario

Table A6-1 provides the generating system reliability in years per day for this scenario. The results are significantly lower than HECO's reliability guideline of 4.5 years per day, in all years.

Table A6-1:

Generation System Reliability for the Alternate Higher Load Scenario

Year	Generation System Reliability (years/day)
2007	0.3
2008	0.3
2009	0.6
2010	0.6
2011	0.9
2012	0.9

Table A6-2 provides HECO's Rule 1 and Rule 2 analysis results for this scenario, indicating a Rule 1 reserve capacity shortfall (in 2008) and Rule 2 reserve capacity shortfalls (in 2007-2009, and 2011).

Table A6-2:
Rule 1 and Rule 2 Analysis
Alternate Higher Load Scenario

Year	Rule 1 Results (MW)	Rule 2 Results (MW)
2007	28	-12
2008	-4	-44
2009	23	-17
2010	48	8
2011	34	-6
2012	92	52

2. <u>Alternate Two-Month 90 MW Outage Scenario</u>

Table A6-3 provides the generating system reliability in years per day for this scenario. The results are significantly lower than HECO's reliability guideline of 4.5 years per day, in all years.

Table A6-3:
Generation System Reliability for the Alternate Two-Month 90 MW Outage Scenario

Year	Generation System Reliability (years/day)
2007	0.7
2008	0.7
2009	1.6
2010	1.6
2011	2.1
2012	1.8

Table A6-4 provides HECO's Rule 1 and Rule 2 analysis for this scenario, indicating Rule 2 reserve capacity shortfalls (in 2007 and 2008).

Table A6-4:
Rule 1 and Rule 2 Analysis
Alternate Two-Month 90 MW Outage Scenario

Year	Rule 1 Results (MW)	Rule 2 Results (MW)
2007	31	-9
2008	21	-19
2009	81	41
2010	104	64
2011	94	54
2012	95	55

3. Alternate 5-Year Average EFOR Scenario (lower EFOR)

Table A6-5 provides the generating system reliability in years per day for this scenario. The results are lower than HECO's reliability guideline of 4.5 years per day, in all years.

Table A6-5:
Generation System Reliability for the Alternate 5-Year Average EFOR Scenario

Year	Generation System Reliability (years/day)
2007	1.2
2008	1.2
2009	2.5
2010	2.0
2011	4.0
2012	3.5

Because HECO's Rule 1 and Rule 2 criteria are deterministic and do not take into account the reliability of each generating unit, a 5-Year Average EFOR sensitivity analysis has no impact on the results. Therefore, the Rule 1 and Rule 2 results for the Alternate 5-Year Average EFOR scenario are the same as the Reference Scenario Rule 1 and Rule 2 results (provided in Section 4.3.1.2).

4. Alternate 60 MW Higher Load with Lower EFOR Scenario

Table A6-6 provides the generating system reliability in years per day for this scenario. The results are significantly lower than HECO's reliability guideline of 4.5 years per day, in all years.

Table A6-6:
Generation System Reliability for the Alternate 60 MW Higher Load with Lower EFOR Scenario

Year	Generation System Reliability (years/day)
2007	0.3
2008	0.3
2009	0.7
2010	0.6
2011	1.1
2012	0.9

Table A6-7 provides HECO's Rule 1 and Rule 2 analysis for this scenario, indicating a Rule 1 reserve capacity shortfall (in 2008) and Rule 2 reserve capacity shortfalls (in 2007-2009, and 2011).

Table A6-7:
Rule 1 and Rule 2 Analysis
Alternate 60 MW Higher Load with Lower EFOR Scenario

Year	Rule 1 Results (MW)	Rule 2 Results (MW)
2007	28	-12
2008	-4	-44
2009	23	-17
2010	48	8
2011	34	-6
2012	92	52

5. Alternate 60 MW Higher Load with Two-Month 90 MW Outage Scenario

Table A6-8 provides the generating system reliability in years per day for this scenario. The results are significantly lower than HECO's reliability guideline of 4.5 years per day, in all years.

Table A6-8:
Generation System Reliability for the Alternate 60 MW Higher Load
with Two-Month 90 MW Outage Scenario

Year	Generation System Reliability (years/day)
2007	0.2
2008	0.2
2009	0.4
2010	0.5
2011	0.6
2012	0.5

Table A6-9 provides HECO's Rule 1 and Rule 2 analysis for this scenario indicating Rule 1 reserve capacity shortfalls (in 2007 and 2008) and Rule 2 reserve capacity shortfalls (in 2007-2009 and 2011-2012).

Table A6-9:
Rule 1 and Rule 2 Analysis
Alternate 60 MW Higher Load with
Two-Month 90 MW Outage Scenario

Year	Rule 1 Results (MW)	Rule 2 Results (MW)
2007	-29	-69
2008	-39	-79
2009	21	-19
2010	44	4
2011	34	-6
2012	35	-5

6. No Combustion Turbine Scenario

HECO estimates that the combustion turbine will be installed at Campbell Industrial Park by mid-2009, and Section 3.5 lists the recent achievements which support the reasonableness of this estimate. However, in recognition that the project can be influenced by factors beyond HECO's control, and that estimates for future commercial operation dates can be uncertain, HECO analyzed a scenario under which the new generating unit is NOT installed. For the purposes of evaluating this sensitivity, the CT is entirely absent, rather than merely delayed by a year or two. Under this No Combustion Turbine Scenario, capacity from the temporary distributed generators installed as a mitigation measure is included. Other assumptions, such as the load forecast, impacts for energy efficiency DSM and load management, generating unit EFOR, and planned maintenance schedules remain identical to the 2007 AOS Reference Scenario.

Table A6-10 provides the generating system reliability in years per day for this scenario. The results are significantly lower than HECO's reliability guideline of 4.5 years per day, in all years.

Table A6-10:
Generation System Reliability for the No Combustion Turbine Scenario

Year	Generation System Reliability (years/day)
2007	1.1
2008	1.1
2009	0.7
2010	0.6
2011	0.7
2012	0.7

Table A6-11 provides the reserve capacity shortfall corresponding to the calculated reliability shown in Table A6-10.

Table A6-11:
Reliability Guideline Reserve Capacity Shortfall for the No Combustion Turbine Scenario

Year	MW
2007	-70
2008	-70
2009	-90
2010	-100
2011	-90
2012	-90

Table A6-12 provides HECO's Rule 1 and Rule 2 analysis for this scenario indicating Rule 2 reserve capacity shortfalls (in 2009-2011).

Table A6-12:
Rule 1 and Rule 2 Analysis
for the No Combustion Turbine Scenario

Year	Rule 1 Results (MW)	Rule 2 Results (MW)
2007	88	48
2008	56	16
2009	1	-39
2010	37	-3
2011	10	-30
2012	69	29

Appendix 7:

HECO Equivalent Forced Outage Rate (EFOR) Discussion

1. Introduction

EFOR is a unit-specific measure of lost megawatt hours due to forced outages or unplanned unit deratings

- "Forced Outages" are unplanned unit shutdown caused by a number of factors, e.g., automatic or programmed protective trips, operator-initiated trips due to equipment malfunction or maintaining compliance with established permits, or operator error.

- "Deratings" are unplanned unit events caused by equipment malfunction or deterioration such that full load cannot be achieved. For example, a generating unit that can only produce 78 MW of its 90 MW normal capacity is considered derated.

2. Factors Affecting EFOR

Major factors contributing to EFOR include unit and equipment age (older units tend to have higher EFOR than newer units), operating duty (i.e., minimum load, on/off cycling, etc.), human factors, compliance with environmental restrictions, and safety. The severity of unit operating duty (running units harder) increases as the units age, because the older units, over time, become less efficient than the newer units. Another way of understanding this is that new units in a particular class, i.e., non-reheat steam units, started out as base loaded units when they were first placed on line, because they tended to be the largest and most efficient. Over time, newer, larger and more efficient units were added to the HECO system, i.e., reheat steam units, and were baseloaded, leaving the relatively less efficient non-reheat units to cycle. As a consequence of shifting mode of operation from baseload when they were new (least severe on equipment), to cycling when they were older (most severe on equipment), wear and tear on equipment increased as the units got older. HECO baseloaded reheat steam units are also being affected by the impact of daily minimum loads on their respective auxiliary equipment. The cause is attributed to the addition of IPP baseloaded capacity in the early 90's that required HECO baseload units to share the minimum load with IPP baseload units. Due to the relative differences in efficiency between the HECO reheat units and the IPP units, HECO baseload units are operated down to their respective minimum loads to meet system requirements while IPP baseloaded units operate close to their maximum output. In order to operate safely at minimum loads, HECO baseload units must cycle (on/off operation) critical auxiliaries on a daily basis.

This mode of operation increases the wear and tear on critical auxiliaries and increases the potential for breakdown and subsequent operation with a derating.

All of HECO's steam units were originally designed to operate in baseload duty, i.e., operate 24 hours a day. They were not designed to withstand the stresses of daily starting and stopping. However, as the larger, more efficient units, such as Kahe Units 1 to 6 came into service, they were placed into baseload duty, and the smaller, less efficient units, such as Waiau Units 3 to 6, were placed into cycling duty to support the daily changes in peak loads.

Critical auxiliary equipment, such as pumps and motors, on HECO's baseload units[30] also experience cycling stresses from daily on/off operation. While these units run 24 hours a day, seven days a week, they must increase their output during the high demand daytime hours and reduce their output during the low demand night-time hours. During the low demand periods, some of the critical auxiliary equipment must be turned off to support stable and reliable low load operation. As demand increases at the start of the day, they must be turned on again. This daily on/off cycling of critical auxiliary equipment causes thermal, mechanical and electrical stresses that can result in unanticipated breakdowns and unit deratings.

The ages of the units also played a large role in the higher EFORs of recent years. Generating units are made up of very complex systems and equipment that wear and tear at different rates as they age. Older mechanical and electrical equipment are prone to break down more frequently than newer equipment. Oftentimes, imminent breakdowns cannot be detected despite best efforts to regularly inspect and maintain the equipment. Also, acquiring replacement parts on older equipment become more challenging due to obsolescence, and substitute parts that are often reengineered by other than the original equipment manufacturer (OEM) require several iterations to refine the design. This can increase the amount of time a unit remains out of service, thereby increasing the EFOR statistic.

3. Unpredictable Nature of EFOR

Unplanned deratings, major component failures, and unit trips are extremely difficult to predict as evidenced by the erratic nature of observed EFOR statistics. When reliability problems occur that result in forced outages or derates, corrective actions are typically taken as soon as practical, depending on the availability of resources. In the case of unplanned deratings, corrective action may be delayed depending on expected system demand, available reserve margin, outage priorities on other units, and parts/materials availability.

[30] HECO's baseload units include Kahe Units 1 to 6 and Waiau Units 7 and 8. The Kalaeloa, AES and H-Power units are also baseload units.

4. Forward-looking EFOR Rates used in the 2007 AOS

As explained above, it is extremely difficult to predict EFOR rates, and this is especially true under operating conditions of decreasing reserve margins. 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 2007 AOS analysis and the rationale for them are described in the following paragraphs.

4.1. Honolulu Units 8 and 9

In the 2006 AOS, the forward looking EFORs for Honolulu Units 8 and 9 were 12.8% based on 2-year average of actual EFOR for Honolulu Unit 8 in 2004 and 2005. The actual EFOR for 2006 for Honolulu Units 8 & 9 were 3.1% and 26.1%, respectively, and averaged 14.6% for the two units. On average the reliability compared well with the forecast. For the 2007 AOS analysis, it was decided to expand the average period from 2 years to 3 years and to include both Honolulu 8 and 9 actual EFOR statistics in the calculation. This approach also recognizes that the units will be dispatched and operated similarly in 2007 as they were in recent years. As a result an EFOR of 11.3%, 1.5% less than that utilized for the 2006 AOS analysis, is recommended for the 2007 AOS forward looking EFOR for Honolulu Units 8 and 9.

4.2. Waiau Units 3 and 4

In the 2006 AOS, the forward looking EFORs for Waiau Units 3 and 4 were 33.5% and 12.8%, respectively. The unusually high value for Waiau Unit 3 was based on its recent history of severe reliability problems resulting in extended derates of the unit [as described in the 2006 AOS]. The actual EFOR for 2006 for Waiau Unit 3 was 24.0%. The actual EFOR statistics for 2006 illustrate a continuation of high EFOR rates that stem back to 2004. However, corrective maintenance performed during the Waiau 3 overhaul in mid-2006 produced improved reliability in the second half of the year, and it is expected to continue in 2007.

The actual EFOR for 2006 for Waiau Unit 4 was 27.2%, which was primarily attributed to problems with the cooling water circulation pumps (prior to its overhaul) and with the new generator exciter (immediately following its overhaul). Corrective maintenance on the pumps and final commissioning of the exciter have resulted in improved reliability. Thus, for Waiau Unit 4 the EFOR for 2007 is expected improve compared to the actual EFOR in 2006.

Waiau Units 3 and 4 are of similar design, size, and vintage as Honolulu Units 8 and 9, and their respective duty cycles are expected to be similar in 2007. For these reasons and because of the improved reliability expected from the corrective maintenance performed in 2006, an EFOR of 11.3%, the same as that for Honolulu Units 8 and 9, is recommended for the 2007 forward looking EFOR for Waiau Units 3 and 4.

4.3. <u>Waiau Units 5 and 6</u>

In the 2006 AOS, the forward looking EFORs for Waiau Units 5 and 6 were 2.9% based on actual EFOR for Waiau Unit 6 in 2005 and the expectation for slightly lower reliability in the year following an overhaul, owing to break-in of new equipment. The actual EFOR for 2006 for Waiau Units 5 and 6 were 1.7% and 9.2%, respectively, and averaged 5.4% for the two units. On average the reliability compared fairly well with the forecast. For the 2007 AOS analysis, it was decided to utilize an average of the actual EFORs for both units for the most recent 3 years. This approach also recognizes that the units will be dispatched and operated similarly in 2007 as they were in recent years. As a result an EFOR of 2.6%, 0.3% less than that utilized for the 2006 AOS analysis, is recommended for the 2007 AOS forward looking EFOR for Waiau Units 5 and 6

4.4. <u>Waiau Unit 7, Waiau Unit 8, Kahe Unit 3, and Kahe Unit 4</u>

These four units are of similar size, design, and vintage, and are dispatched as baseloaded units with similar duty cycles. Accordingly, in the 2006 AOS, the forward looking EFORs were the same for these four units. In 2006, the forward looking EFORs were 7.7% based on a review of the actual EFORs for these four units during 2004 and 2005, and the expectation that major maintenance work on Waiau 8 in late 2005 would correct the unusually high EFOR of 23.5% that the unit incurred in 2005. The actual EFOR for 2006 for each unit was below this value and they averaged 2.2%. For the 2007 AOS analysis, it was decided to utilize an average of actual EFORs for all four units for the most recent 3 years. This approach also recognizes that the units will be dispatched and operated similarly in 2007 as they were in recent years. As a result an EFOR of 6.6%, 1.1% less than that utilized for the 2006 AOS analysis, is recommended for the 2007 AOS forward looking EFOR for Waiau Units 7 and 8, and Kahe Units 3 and 4.

4.5. <u>Waiau Units 9 and 10</u>

In the 2006 AOS, the forward looking EFORs for Waiau Units 9 and 10 were 10.0% based on actual EFOR for Waiau Unit 10 in 2004 and 2005, and the expectation that the EFOR for Waiau Unit 9 would improve significantly from actual EFOR levels in 2004 and 2005 as a result of a major overhaul. The actual EFOR for 2006 for Waiau Units 9 and 10 were 14.7% and 26.7%, respectively, and averaged 20.7% for the two units. On average the reliability did not compare well with the forecast. For the 2007 AOS analysis, it was decided to utilize an average of the actual EFORs for Waiau Unit 10 for the most recent 3 years (12.7%). This approach also recognizes that the units are in relatively similar condition and will be dispatched and operated similarly in 2007 as

Waiau Unit 10 was recent years. As a result an EFOR of 12.7%, 2.7% higher than that utilized for the 2006 AOS analysis, is recommended for the 2007 AOS forward looking EFOR for Waiau Units 9 and 10.

4.6. Kahe Units 1 and 2

In the 2006 AOS, the forward looking EFORs for Kahe Units 1 and 2 were 4.3% based on the average of Kahe Unit 1 actual EFOR levels for 2004 and 2005, and the expectation that EFORs would move upward some from their historical averages due to their increasing age and reduced scheduling flexibility caused by tight reserve margins. The actual EFOR for 2006 for Kahe Units 1 and 2 were 2.6% and 1.8%, respectively, and averaged 2.2% for the two units. On average the reliability compared fairly well with the forecast. For the 2007 AOS analysis, it was decided to expand the average period from 2 to 3 years and to continue to use actual EFOR values from Kahe Unit 1 as the basis for both units. This approach also recognizes that the units will be dispatched and operated similarly in 2007 as they were in recent years. As a result an EFOR of 3.2%, 1.1% less than that utilized for the 2006 AOS analysis, is recommended for the 2007 AOS forward looking EFOR for Kahe Units 1 and 2.

4.7. Kahe Unit 5

In the 2006 AOS, the forward looking EFOR for Kahe Unit 5 was 5.5% based on the average of Kahe Unit 5 actual EFOR levels for 2004 and 2005. The actual EFOR for 2006 for Kahe Unit 5 was 3.1%. The actual EFOR compared fairly well with the forecast. For the 2007 AOS analysis, it was decided to expand the average period from 2 to 3 years. This approach also recognizes that Kahe Unit 5 will be dispatched and operated similarly in 2007 as it was in recent years. As a result an EFOR of 4.6%, 0.9% less than that utilized for the 2006 AOS analysis, is recommended for the 2007 AOS forward looking EFOR for Kahe Unit 5.

4.8. Kahe Unit 6

In the 2006 AOS, the forward looking EFOR for Kahe Unit 6 was 4.9% based on the average of Kahe Unit 6 actual EFOR levels for 2004 and 2005. The actual EFOR for 2006 for Kahe Unit 6 was 2.8%. The actual EFOR compared fairly well with the forecast. For the 2007 AOS analysis, it was decided to expand the average period from 2 to 3 years. This approach also recognizes that Kahe Unit 6 will be dispatched and operated similarly in 2007 as it was in recent years. As a result an EFOR of 4.0%, 0.9% less than that utilized for the 2006 AOS analysis, is recommended for the 2007 AOS forward looking EFOR for Kahe Unit 6.

5. Evaluate an Expanded Inventory of Critical Spare Parts

Availability of spare parts can impact the duration of an unplanned outage. The benefits of having a vast inventory of spare parts readily available must be balanced against the likelihood that the spare part will be needed, the carrying cost of the spare parts inventory and the criticality of the system/equipment supported by the spare parts inventory. Estimated delivery times for items that are not kept in inventory must also be considered.

As part of the ongoing Power Supply Reliability Optimization (PSRO) program, HECO has been evaluating expansion of the inventory of spare parts. A major "building block" of the PSRO program is the Maintenance Basis which specifies for all of the equipment in the power plants the scope and frequency of maintenance to be performed on that equipment. In 2006, HECO completed the development of the Maintenance Basis for the HECO power plant equipment. Integral to the Maintenance Basis is assignment of the equipment to one of nine levels of criticality based on the impacts of failure of the equipment on reliability. For the equipment assigned to the top three levels of criticality, HECO will be reassessing the spare parts inventories to identify what additional spare parts may be needed to improve the availability and reliability of that equipment and thus improve overall generation reliability.

6. HECO Generating Unit Maintenance Program Review and Evaluation

In 2006, HECO also commissioned EPRI Solutions, Inc. (ESI) to perform a review of HECO's Power Supply operations, maintenance and outage management programs. The review report, entitled *"Review of HECO's Power Supply Operations, Maintenance, and Outage Management Programs"* was filed with the Commission on October 20, 2006, along with HECO's summary of the report scope, findings, and candidate actions.

The candidate actions were divided into five groups:

1. Scheduled overhauls and outages,
2. Corrective and preventive maintenance,
3. Organization
4. Technology application and data analysis, and
5. Training.

Overall, HECO is in agreement with the findings of the ESI report and agrees that the candidate actions presented by ESI represent opportunities to improve the availability and reliability of HECO's generation. For many of the candidate actions, HECO already has in place programs and projects to address the candidate actions, or these programs and projects are in the process of being implemented.

Additional details are available in the 78 page ESI report, or in the six page HECO summary transmittal.

Appendix 8:

High-Level Evaluation of 10 Years per Day Loss of Load Probability

One potential means to address the ever increasing planning uncertainty and complexity is to revise the capacity planning guideline. As explained in Section 4.2, HECO 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 assumptions, many of which the utility has little or no sole control over, then the utility could plan for a higher reserve margin. Such an approach would not eliminate quickly-changing assumptions, 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.

HECO plans to include a tradeoff analysis in its IRP process. For the purposes of this sensitivity analysis, HECO 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 firm capacity that would be required to meet this higher reliability guideline. Table A8-1 illustrates the results of this sensitivity analysis, using the Reference Scenario.

Table A8-1:
Reserve Capacity Shortfall for 10 Years/Day LOLP,
using Reference Scenario Assumptions, MW

Year	Reference Scenario (4.5 Years/Day LOLP)	Alternate Scenario (10 Years/Day LOLP)
2007	-70	-100
2008	-70	-100
2009	-40	-70
2010	-40	-80
2011	-20	-60
2012	-20	-50

HECO has not had the opportunity to fully scrutinize and benchmark these results. A larger difference between the scenarios had been expected. For example, in year 2011, Table A8-1 indicates that 20 MW must be added to restore the Reference Scenario to the 4.5 years per day LOLP, while 60 MW would achieve a 10 years per day LOLP. This modest difference of 40 MW (60 MW – 20 MW = 40 MW) is not intuitive for the large change in LOLP, and therefore, the results should be considered preliminary until a more comprehensive analysis can be performed as a part of the IRP process.