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PUBLIC UTILITIES COMMISSION

Edward L. Reinhardt
President

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
Maui Electric Company, Limited ("MECO")

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

This Adequacy of Supply ("AOS") report will show that MECO has sufficient capacity to meet the forecasted loads on the islands of Maui, Lanai and Molokai. Although MECO may not, at times, have sufficient capacity on the Maui and Lanai systems to cover for the loss of the largest unit, MECO will implement appropriate mitigation measures to overcome the insufficient reserve capacity situation.

1.0 Maui Division

1.1 Peak Demand and System Capability in 2007

Maui's 2007 system peak occurred on November 7, 2007, and was 204,400 kW (net) or 209,300 kW (gross). The total system capability of Maui was 260.3 MW (net) at the time of the system peak, resulting in a reserve margin of approximately 27% over the 2007 system peak, as shown in Attachment 1.

1.2 Determination of Maui Division's Adequacy of Supply

1.2.1 Maui Division Capacity Planning Criteria

The following capacity planning criteria are used to determine the timing of an additional generating unit for the Maui Division:

[1] MECO's Adequacy of Supply ("AOS") report is due within 30 days after the end of the year.

New generation will be added to prevent the violation of the rule listed below where "units" mean all units and firm capacity suppliers physically connected to the system, and "available unit" means an operable unit not on scheduled maintenance.

The sum of the reserve ratings of all units minus the reserve rating of the largest available unit minus the reserve ratings of any units on maintenance must be equal to or greater than the system peak load to be supplied.

In addition, consideration will be given to maintaining a reserve margin of approximately 20 percent based on Reserve Ratings.

The primary inputs that are used to determine whether additional firm capacity should be added are the projection of peak demand, net of the peak reduction benefits of energy efficiency demand-side management ("DSM"), the reserve rating of each firm capacity generating unit that is on the system, and the planned outage schedule of the generation units. Peak demand that must be served by central-station generating units can also be reduced by the peak reduction benefits of load management programs and Distributed Generation ("DG") systems. The forecast of peak demand, the peak reduction benefits of energy efficiency DSM and load management programs, the peak reduction benefits of DG systems and Maui's total firm capacity are discussed below.

1.2.2 Other Considerations in Determining the Timing of Unit Additions

The need for new generation is not based solely on the application of the criteria previously mentioned. As capacity needs become imminent, it is essential that MECO broaden its consideration to ensure timely installation of generation capacity necessary to meet its customers' energy needs. As stated in the Capacity Planning Criteria:

The preceding rules apply to capacity planning in long-range generation expansion studies. The actual commercial operation date for the next unit to be added shall also be determined using these rules as guides, with due consideration given to short-term operating conditions, equipment procurement, construction, regulatory approvals, financial and other constraints, etc.

Other near-term considerations may include:

- the current condition and rated capacity of existing units;

- the preferred mix of generation resources to meet varying daily and seasonal demand patterns at the lowest reasonable capital and operating cost;
- the forecasted minimum demand;
- required power purchase obligations and contract terminations;
- the unpredictable output of supplemental resources;
- the uncertainties surrounding Non-Utility Generation ("NUG") resources;
- transmission system considerations; and
- system stability considerations for MECO's isolated system.

1.3 Peak Demand

1.3.1 Recorded Peak Demand

MECO's 2007 system peak of 209.3 MW (gross) or 204.4 MW (net) occurred on November 7, 2007. The 2007 annual gross peak was 1.5 MW lower than the 2006 gross system recorded peak of 210.8 MW (gross) or 206.4 MW (net) set on August 14, 2006. The following table shows the Maui historical system peak demand.

Table 1.3.1-1: Recorded System Peak Demand

Year	Recorded System Peak, MW-Net
1997	170.9
1998	172.3
1999	176.3
2000	181.2
2001	187.0
2002	189.8
2003	197.7
2004	206.5
2005	202.1
2006	206.4
2007	204.4

MECO's lower system peak in 2007 compared to 2006 can be attributed in part to more moderate and wetter weather compounded by the temporary loss of The Ritz-Carlton, Kapalua and Renaissance Wailea Beach Resort in the third quarter of 2007. This downward trend was offset by new load growth (i.e., increase in number of customers and new construction) from customers such as the Kaanapali Ocean Resorts Phase II, Pomaikai Elementary School, St. Francis Dialysis Center, and new home construction in central, south, and west Maui.

1.3.2 Projected Peak Demand

The following table shows the projected peak demand for Maui over the next eight (8) years:

Table 1.3.2-1: Maui Forecast Peak Demand (2008-2015)

Year	Forecast System Peak Demand without DSM and CHP Impacts, MW-Net	Forecast Future and Acquired DSM Impacts, MW-Net	Forecast Small Market CHP Impacts, MW-Net	Forecast Impacts of Load Management DSM, MW Net	Forecast System Peak Demand with Peak Reduction Benefits of DSM and CHP, MW-Net
2008	226.0	11.3	0.9	1.1	212.7
2009	233.1	12.2	1.3	2.7	216.8
2010	240.4	13.3	1.8	4.2	221.1
2011	244.5	14.4	1.8	5.2	223.1
2012	249.7	15.1	1.8	7.0	225.8
2013	253.4	15.7	1.8	7.8	228.1
2014	257.6	16.5	1.8	8.1	231.2
2015	262.1	17.1	1.8	8.3	234.9

Although the actual system peak demand slightly decreased from 2006 to 2007, MECO projects future system peaks to increase. The reasons for expected peak increases include the return to normal weather and various new projects such as the expansion of the Kaanapali Ocean Resorts, Maui Ocean Club's new tower, Lahaina Gateway and several residential subdivisions throughout Maui. Additionally, the Ritz-Carlton, Kapalua returned in early 2008 following the completion of the majority of the property wide renovation. As shown in Attachment 1, Table 1, the peak demand is forecasted to continue to increase.

1.3.3 Uncertainties in Projected Peak Demand

Uncertainties in projecting Maui's peak demand exist that could result in either lower or higher than expected peaks. Climate changes throughout the year could result in higher peaks if temperatures increase, which directly results in increased energy consumption (i.e., air conditioning loads). Conversely, cooler temperatures will result in a decrease in air conditioning loads, resulting in less energy consumption and lower peaks. Other climate changes, which Maui has experienced in the past, have resulted in drought conditions that affect water pumping loads. Increases or decreases in these pumping loads could also affect the Maui system peak.

Changes in forecasted peak reduction benefits from energy efficiency DSM programs could also affect the Maui system peak. As detailed in Section 1.4.1, on February 13, 2007 in the Energy Efficiency Docket (Docket No. 05-0069), the Commission issued Decision and Order No. 23258 that ordered the energy efficiency programs transition to a non-utility administrator by January 2009. It is unknown how this transition will affect the peak reducing impacts of the energy efficiency DSM programs. Lower than forecasted impacts will most likely result in higher peaks.

New development on the island of Maui in the future also adds to the uncertainty of the Maui system peak. These projects, whether known or unknown by the utility regarding project concept, may have construction completion dates and energy consumption levels that are not quantifiable until the project is near completion. Therefore, the level of impact on the system peak is relatively unknown and difficult to forecast. One such project is the biofuel refining plant that is being proposed by BlueEarth Biofuels, LLC. When first announced in February 2007, it was predicted that the first phase of the plant would be in service by 2009. Based on a more recent forecast, the plant is scheduled to be in operation sometime in the 2nd quarter of 2010. Subsequent phases 2 and 3 are predicted to be in service in the following years. Capacity impact and energy consumption of the plant have not been finalized. Therefore, the peak forecast provided in Table 1.3.2-1 does not include the future demand from the BlueEarth Biofuels facility.

Other projects that illustrate the uncertainties in the forecast include the Renaissance Wailea Beach Resort and The Ritz-Carlton, Kapalua. The forecasted demolition of the Renaissance Wailea Beach Resort did not materialize as originally expected by the end of 2006. The hotel closure was delayed multiple times and finally closed its doors on September 7, 2007. The hotel is currently planned to be replaced by a Baccarat hotel in 2010. The Ritz-Carlton, Kapalua announced in January 2007 that it would temporarily close its doors in July 2007 to undergo a property-wide renovation. The Ritz-Carlton did not provide any guidance prior to the announcement that it was considering an extensive renovation and temporary closure.

In order to evaluate the potential impact of the uncertainties that the forecast demand would have on the need for capacity, a scenario that included the Blue Earth Biofuels, LLC project was examined. This scenario evaluation is provided in Attachment 4.

1.4 Reductions in Peak Demand

1.4.1 MECO's Energy Efficiency DSM Programs

On February 13, 2007, the Commission issued Decision and Order No. 23258 in the Energy Efficiency Docket (Docket No. 05-0069) in which the Commission ordered that the energy efficiency programs transition to a non-utility administrator by January 2009. The impact of the transition is unknown at this time and there are uncertainties associated with obtaining the peak reduction impacts from a new, yet to be defined market structure. Should customer participation in the DSM programs be lower than estimated or delayed, the actual peak demand on Maui may exceed the peak forecast amounts used in this AOS filing.

On September 27, 2007, the Commission opened Docket No. 2007-0323 which will examine the selection of the non-utility administrator and refine the details of the new market structure. MECO will work with the administrator to provide a smooth transition in which customers are continuously encouraged to pursue cost effective energy efficiency improvements. The expanded set of DSM programs developed in IRP-3 were designed to aggressively acquire energy conservation resources in a cost-effective manner as MECO anticipates future resource needs. That is, there are net benefits of the DSM programs to the ratepayers when compared to the revenue requirements necessary if the DSM programs were not pursued, regardless of the administrative structure of DSM.

MECO also proposed modifications to its existing DSM programs such as increasing the incentives within the Commercial & Industrial programs and offering of compact fluorescent light incentives to residential customers beginning in 2008. A delay in receiving a decision on MECO's requests, which results in delayed or reduced impacts, could result in higher peak loads.

Unlike the Energy Efficiency DSM Programs, load management DSM programs will continue to be administered by the utilities.

1.4.2 Maui Load Management DSM Program

In MECO's previous AOS, filed with the Commission on February 27, 2007, MECO assumed that its proposed load management DSM program applications would be filed in 2007, approved in late 2007 or early 2008, with full-scale impacts realized in 2008. MECO now expects to file these program applications shortly for its residential and commercial and industrial direct load control programs, RDLC and CIDLC, respectively. The current forecast is that Commission approval will now occur in early 2008, with impacts beginning in mid to late 2008 and full-scale impacts realized in 2009.

MECO's load control programs will be similar in design to HECO's programs. Although HECO's RDLC and CIDLC programs were approved in October 2004, HECO submitted requests for modifications to increase the budget of both programs in March 2006 for additional funding of equipment and installation costs and received approval in June 2006 and November 2006 for the CIDLC and RDLC programs respectively. MECO decided it would be prudent to assess HECO's program successes and challenges before filing its own applications and will be incorporating the modifications in its load management programs, as appropriate for MECO's customer base. The following table shows the cumulative forecasted peak impacts of the load management DSM programs for years 2008-2015.

Table 1.4.2-1: Load Management DSM Program Impacts (2008-2015)

Year	Forecasted Impacts of Load Management DSM (MW-Net)
2008	1.1
2009	2.7
2010	4.2
2011	5.2
2012	7.0
2013	7.8
2014	8.1
2015	8.3

1.4.3 Net Peak Demand

The peak reduction benefits of energy efficiency DSM are reflected in the forecast of peak demand shown in Table 1.3.2-1. The load management programs are treated as a resource that can offset demand and are reflected in the calculation of reserve margins shown in Table 1 in Attachment 1.

1.4.4 Combined Heat and Power ("CHP")

Firm DG resources can provide generating capacity if they can be reliably dispatched by the utility, or can reduce peak demand served by the utility if operated by customers. MECO has been including forecasted firm DG resources, namely CHP, in its AOS evaluations for the past several years. The CHP forecast used in the present AOS filing is unchanged from the forecast used in the 2007 AOS report (which was dated January 9, 2007) for the following reasons: (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) the Commission criteria required to be met by MECO in order to provide customer-sited DG projects on a regulated utility basis, and (3) other uncertainties concerning customer-sited DG.

The cumulative forecasted impacts for the years 2008-2015, are shown in the table below. No new CHP systems were commissioned on Maui in 2007. These forecasted impacts of the proposed CHP Program on future system peaks are also indicated in Attachment 1.[2]

[2] For purposes of this report, CHP systems are reflected in the System Peak numbers (based on the net equivalent capacity of the CHP system, taking into account the electrical capacity supplied to a customer, the reduction of the customer's electrical load through waste heat application for the system, and a reduction in line losses). The load reduction impacts of CHP systems and/or DG owned by third parties are also reflected in the System Peak numbers.

Table 1.4.4-1: Small CHP Market Impacts (2008-2015)

Year	Forecasted Impacts of Small CHP Market (MW Net)
2008	0.9
2009	1.3
2010	1.8
2011	1.8
2012	1.8
2013	1.8
2014	1.8
2015	1.8

1.5 Total Firm Capacity

1.5.1 MECO Firm Capacity

1.5.1.1 Maalaea Unit 13 Restored to Service

On December 9, 2005, Maalaea Unit 13, a 12.34 MW (net) Mitsubishi diesel engine generator, suffered equipment failure causing extensive damage to the engine crankshaft, frame, and cylinder blocks. Repairs to Maalaea Unit 13 have been completed and the unit was returned to operation on July 9, 2007.

1.5.1.2 Maalaea Unit 18 Completed

On October 27, 2006, Maalaea Unit 18, a nominal 17,100 kW (net) steam turbine generator, was placed into commercial operation.[3] Maalaea Unit 18 is the third and final phase of a Dual Train Combined Cycle system that consists of two combustion turbines and the steam turbine generator totaling 56,780 kW (net).

[3] Commission approval for the purchase and installation of Maalaea Unit 18 was received in Decision & Order No. 13730, filed January 11, 1995, in Docket No. 7744.

1.5.1.3 Hana Distributed Generation

In the previous AOS report that was filed on February 27, 2007, it was stated that MECO planned to install communication and controls to the two 1,000 kW standby diesel engine generators, located at Hana Substation No. 41, to enable the units to be operated as dispatchable distributed generation. This communication and controls project commenced in 2007 and is expected to be completed in the 2nd quarter of 2008. This project will provide MECO with the means to operate the Hana generators in parallel to the system and as emergency units. These units will also have the capability to be indirectly, remotely controlled and automatically brought on line. Currently, the units are used for fully automated emergency generation and are also used as dispatched generation, although requiring manual operation. As such, the units are currently utilized as both emergency generation and dispatchable generation. As a result, the Hana units have been designated as firm capacity and their capacity is included in the total reserve rating of the Maui system capability.

1.5.1.4 Total MECO Firm Capacity

MECO will have a total of 246.3 MW-net of firm capacity with the completion of the Hana communication and controls project in 2008. A summary of MECO's firm capacity, as of December 31, 2007, is shown in Attachment 3.

1.5.2 HC&S Power Purchase Agreement ("PPA")

MECO filed a letter with the Commission in Docket No. 6616 (Hawaiian Commercial & Sugar Company ["HC&S"]), on July 25, 2007, which informed the Commission that MECO and HC&S agreed on July 2, 2007 not to issue a notice of termination of the PPA resulting in termination of the PPA prior to the end of the day on December 31, 2014.[4] This agreement was reached so that HC&S will have more certainty as to the future revenue sources supporting its sugar business, MECO will be able to rely on the continued availability of power from HC&S (a firm, non-fossil fuel power producer) beyond the end of 2011 in planning MECO's generating system and in meeting its Renewable Portfolio Standards, and both parties will have additional time in which to consider HC&S' future plans before negotiating a new, long-term PPA. For planning purposes, MECO assumes the HC&S PPA will

[4] Previous agreement between MECO and HC&S (June 28,2005) not to issue a notice of termination of the PPA resulted in the termination of the PPA prior to the end of the day on December 31, 2011. The resulting need date for new firm capacity was deferred from 2009 to 2011.

terminate at the end of 2014. However, MECO will continue to have discussions with HC&S regarding the future of their operations. This may lead to negotiations for a possible agreement not to terminate the PPA beyond 2014. If the PPA is assumed to continue in effect beyond 2014, the timing for the need for future increments of firm capacity will be affected.

1.5.3 Total Firm Capacity on Maui

The total firm generating capacity on Maui will be 262.3 MW-net, including both MECO and HC&S generation and with the completion of the Hana communication and controls project in 2008

1.5.4 As-Available Generation

Two Independent Power Producers ("IPPs") provide energy to MECO on an as-available basis. As-available generation is not counted as firm capacity.

1.5.4.1 Kaheawa Wind Power ("KWP")

On June 9, 2006, KWP, an IPP, completed construction of a 30 MW wind farm and began providing energy to the Maui system. Although the installation of this wind resource will provide the Maui system with up to 30 MW of additional energy production, the Maui system capability will not be affected because the wind resource is an as-available resource, which is not dispatchable and cannot provide given amounts of power at scheduled times.

1.5.4.2 Makila Hydro ("Makila")

On September 22, 2006, Makila, an IPP, completed construction of a 500 kW run-of-river hydro-electric facility and began providing energy to the Maui system.

As of October 15, 2006, Makila Hydro has been unable to provide energy to MECO due to equipment failure. Makila Hydro anticipates repairs to be completed by the second quarter of 2008 and resume energy production. Since it is an as-available generating unit, it does not affect Maui's firm generating capacity.

1.6 Analysis of MECO's Need for Additional Firm Capacity

Based on the forecast provided in Section 1.3.2 above (including the peak reduction benefits of energy efficiency DSM), the projected peak reduction benefits of load management programs, the projected peak reduction benefits of the CHP programs, the total existing firm capacity on the MECO system, Maui Division's planned maintenance schedule dated October 17, 2007, and the application of MECO's capacity planning criteria, the projected reserve capacity shortfalls are shown in Table 1.6-1 below, assuming no new firm capacity is added to the system.

Table 1.6-1: Load Service Capability Margin Shortfall and Reserve Capacity Deficit Based on 20% Reserve Margin

Year	Forecast Peak Demand, MW-net	Total Firm Capacity on MECO System, MW-net	Largest Load Service Capability Margin Shortfall (Rule 1) MW-net	Largest Reserve Capacity Deficit by 20% Minimum Reserve Margin, MW-net
2008	212.7	262.3	0.0	0.0
2009	216.8	262.3	0.0	0.0
2010	221.1	262.3	0.0	-2.8
2011	223.1	262.3	-1.4	-5.3
2012	225.8	262.3	-4.8	-8.5
2013	228.1	262.3	-6.1	-11.2
2014	231.2	262.3	-9.5	-15.0
2015	234.9	246.3	-29.0	-35.4

1.6.1 Potential Maui Load Service Capability Margin Shortfalls and Reserve Capacity Deficit Based on 20% Minimum Reserve Margin

A Load Service Capability ("LSC") margin shortfall is an indication that there is a reserve margin ("RM") shortfall. RM is the difference between system generating capability and peak demand. The term "load service capability" is a measure of MECO's ability to meet system load requirements, accounting for both planned maintenance and the loss of its largest unit. LSC margin shortfalls (which are indicated by values less than zero) are used as a planning tool to identify potential conditions of generating reserve capacity shortfalls and do not equate to either service interruptions or rolling blackouts. During periods when LSC margin values are less than zero, there is a possibility that a service interruption could occur if the largest unit is lost from service during the peak period. The calculation of reserve margin shortfalls does not take into account the availability of as-available resources, such as the Kaheawa Wind Farm and Makila Hydro. Reserve margin shortfalls do not equate to rolling blackouts. Other factors must be considered when making an assessment of the possibility that available generation will be insufficient to serve the system load (i.e., that rolling blackouts will have to be implemented). These factors include the availability of non-firm resources (such as the wind farm and the hydro facility), differences between actual and forecast peaks (which are impacted by factors such as weather), differences between monthly peaks, and normal weekday and weekend peaks, differences between actual and normal unit capabilities (due to such factors as temporary unit deratings, ambient conditions in the case of Maalaea Units 14, 16, 17 and 19, and the overall condition of the units), differences between actual and planned maintenance schedules (maintenance outages may be extended or shortened, depending on circumstances), and the risk of multiple unit outages.

For planning purposes, *projections* are used to forecast the timing of future resource additions. The following factors affect reserve margin projections:

- System Capability – Long-term projections of unit capabilities based on normal top load ratings are required in addition to the committed capacity of firm power producers with existing Power Purchase Agreements.
- Monthly Peak Forecast – The base load forecast is used.
- Planned Maintenance Schedule – MECO's normal maintenance scheduling practices are used. Maintenance scheduling is performed by the MECO Power Supply Department. Scheduling involves many different operational factors. Maintenance scheduling can be expected to be adjusted several times over the year due to changing operational factors. 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.
- Loss of Largest Unit – The basis for providing sufficient reserve margin to cover this unit while another unit is on planned maintenance.

The determination of both the LSC reserve margin shortfall and the reserve capacity deficit based on a minimum 20% reserve margin can be calculated using system capability charts, as shown in Attachment 2. The LSC reserve margin shortfall is the difference between the system peak reduced by the peak reduction benefits of DSM and CHP, and the system capability reduced by the capacity of the units on planned maintenance and the capacity of the largest available unit. The benefits of the load management impacts are then added to the difference. If the resulting value is positive, then the LSC reserve margin shortfall has not been violated and additional firm generation is not required. If the resulting value is negative, then the LSC reserve margin shortfall has been violated and firm generation will be needed to eliminate the violation. Each month has a different peak value as well as different units on planned maintenance, and thus, the LSC reserve margin shortfall is determined for each month of the year, as reflected the system capability charts.

For example, on page 2 of Attachment 2, the system capability chart for year 2011 shows a LSC reserve margin shortfall occurring in August. This was determined by first calculating the system peak in August (including the reduction of benefits of DSM and CHP), which was 228.2 MW. Next, the system capability (262.3 MW) was reduced by the units on planned maintenance (12.3 MW) and the loss of the largest available unit (28.39 MW). The resulting difference was -6.6 MW. The benefits of the load management impacts (5.2 MW) were then added to the difference, resulting in a LSC margin shortfall of -1.4 MW. This indicates that firm generating capacity is required in August 2011 to prevent a LSC margin shortfall.

Reserve capacity deficit based on a 20% minimum reserve margin is the amount of reserve capacity on the system over and above the system peak, including peak reduction benefits of energy efficiency DSM programs, load management programs, and CHP programs. Reserve margin may be expressed in MW or as a percentage of the system peak. For example, in Attachment 2, in the month of August 2011 the system peak demand is 228.2 MW and the total installed capacity is 262.3 MW. The reserve margin is 39.3 MW, or 39.3 MW / 223 MW = 17.6%. As a guideline, MECO tries to maintain at least a 20% reserve margin. An adequate reserve margin is necessary for several reasons. These include:

- the need to allow generating units to be taken out of service for routine maintenance or overhauls;
- The need to allow for the unexpected outages of generating units that occur from time to time. These unexpected outages are called forced outages;
- The need to allow for growth in demand over time. It is impractical and not economical to install a generating unit every

year to accommodate each year's growth in demand. Therefore, there needs to be sufficient generating capacity on the system to accommodate several years of demand growth; and

- The need to account for the possibility that peak demand may be higher than expected.

However, unlike a LSC margin shortfall, when the reserve margin falls below 20%, firm generating capacity is not necessarily required on the system. However, this is an indication that there may be periods of interruption under certain circumstances.

As indicated in Table 1.6-1, LSC margin shortfalls begin occurring in 2011 and increase in 2012. Therefore, the Maui Division has a need for firm generating capacity beginning in 2011.

As stated in section 1.5.2, with the new agreement in place between HC&S and MECO, MECO assumes the HC&S PPA will terminate at the end of 2014. This assumption leads to the reduction in system capacity by 16 MW beginning on January 1, 2015. As a result, firm generation will be required in 2015 to replace the loss of the HC&S capacity. However, MECO will continue to have discussions with HC&S regarding the future of their operations. This may lead to negotiations for a possible agreement not to terminate the PPA beyond 2014. If another agreement is reached, then MECO will reassess the Maui capacity situation.

1.6.2 <u>LSC Margin Shortfalls and Reserve Capacity Deficit Based on a 20% Minimum Reserve Margin for the 2008 - 2011 Timeframe</u>

No LSC margin shortfalls or reserve capacity deficit based on a 20% minimum reserve margin are expected to occur in 2008 or 2009. Although LSC margin shortfalls are not expected to occur in 2010, a reserve capacity deficit based on a 20% minimum reserve margin could occur. In 2010, Maui's RM is expected to be less than the 20% minimum reserve margin guideline. See page 1 of Attachment 2. MECO does not plan to advance the need date for firm generating capacity to 2010 based on its reserve margin being less than 20% because MECO fully expects to be able to meet demand, even with a unit on maintenance and with the largest remaining available unit forced out of service at the time of the system peak in that year (i.e., MECO will be able to satisfy LSC margin shortfalls of its capacity planning criteria). MECO may implement mitigation measures as detailed in Section 1.8, if the need arises.

In 2011, LSC margin shortfalls could occur in August, as shown in Attachment 2, page 2. In August, a LSC margin shortfall of -1.4 MW could occur when the Maalaea Unit 10 (approximately 12.3 MW) is taken out of service for planned maintenance. In addition, the 20% minimum reserve margin could be violated in August, October, November, and December, with the greatest violation occurring in August where the predicted RM is 17.66%. In 2011, with a 21.18 MW-net simple cycle combustion turbine installed on the system, there will be no LSC margin shortfalls or reserve capacity deficit based on a 20% minimum reserve margin

Between 2012 and the end of 2014, without mitigation measures or additional generation, LSC margin shortfalls are expected to exceed the shortfall levels estimated for 2011. The extent of the LSC margin shortfalls from 2012 through 2014 will be a function of the rate of load growth and the impacts of the Energy Efficiency and Load Management DSM programs. Historically, the annual load growth on the island of Maui has been between 3 to 6 MW. Installation of a large block of generating capacity in 2011 may be needed to accommodate load growth and replace the amount of capacity if DSM impacts fall short of the forecast. Therefore, MECO is continuing to take action to provide a large block of additional firm capacity in 2011 that could prevent LSC margin shortfalls between 2011 and 2014. (See Section 1.7.4, Competitive Bidding for New Generation, and 1.7.7, Parallel Plan for Firm Capacity Needed in 2011).

If, on the other hand, demand is lower than forecast, the installation of capacity could be deferred, depending on the circumstances (such as the extent to which the project has already been installed and the cost of deferral).

MECO will also explore the role that DG may play in providing capacity to prevent LSC shortfalls in 2011. Although there are uncertainties in forecast demand (as explained in Section 1.3.3) DG may be useful in overcoming LSC shortfalls and thereby defer the need for a large block of firm capacity. For example, an increment of 2 to 5 MW of DG capacity may be sufficient to defer the need for the next increment of firm capacity from 2011 to 2012. A discussion of DG is provided in Section 1.8.1.

Beyond 2014, LSC margin shortfalls will be a function of not only the rate of load growth and the impacts of Energy Efficiency and Load Management DSM programs, but also whether or not the HC&S contract is extended or renegotiated. If the HC&S contract is renegotiated, the amount of capacity that HC&S will be obligated to deliver under the contract will also affect the potential for LSC margin shortfalls. HC&S accounts for 16 MW towards Maui's system capacity. For planning purposes, the HC&S contract is assumed to terminate on December 31, 2014. (See Section 1.5.2, HC&S Power Purchase Agreement ("PPA")). Therefore, if HC&S does not provide capacity to the system, then coupled with the annual load growth and potential DSM impacts, the LSC margin shortfall in 2015 and beyond could be substantial. Installation of a large block of generating capacity may be needed to accommodate load growth and replace the possible loss of HC&S capacity. Therefore, MECO is continuing to take action to provide additional firm capacity in 2015 that could prevent LSC margin shortfalls in 2015 and beyond (See Section 1.7.8, Parallel Plan for Firm Capacity Needed in 2015). In addition, MECO plans to continue discussions with HC&S to extend the contract beyond December 31, 2014 to avoid possible LSC margin shortfalls.[5]

1.7 Satisfying MECO's Need for Additional Firm Capacity

1.7.1 MECO's Portfolio Approach to Capacity Planning

Capacity planning in Hawaii has increased in complexity in recent years because of the myriad of resources that may be available to meet consumer energy needs in an efficient and reliable manner at the lowest reasonable cost. Electric utilities must consider all feasible demand-side and supply-side resources in integrated resource planning under the Hawaii Public Utilities Commission's ("Commission") Integrated Resource Planning Framework. In addition, electric utilities in Hawaii must comply with Renewable Portfolio Standards established in Hawaii Revised Statutes, Sections 269-91 to 269-95. Moreover, MECO must comply with the requirements in the Commission's Competitive Bidding Framework, issued on December 8, 2006, in Docket No. 03-0372, to acquire new supply-side resources. Furthermore, in June 2007, the Hawaii state legislature passed Act 234, which establishes as state policy statewide greenhouse gas emissions limits at or below the statewide greenhouse gas emissions levels in 1990 to be achieved by January 1, 2020. It also establishes a greenhouse gas emissions reduction task force to prepare a work plan and regulatory scheme to achieve the statewide greenhouse gas emissions limits.

[5] In accordance with the Competitive Bidding Decision & Order No. 23121, dated December 8, 2006, in Docket No. 03-0372, the Commission adopted "exemptions applicable to qualifying facilities and non-fossil fuel producers" as proposed by the HECO Utilities. These included: (3) power purchase agreement extension for three years or less on substantially the same terms and conditions as the existing power purchase agreements and/or on more favorable terms and conditions; (4) Power purchase agreement modifications to acquire additional firm capacity or firm capacity from an existing facility, or from a facility that is modified without a major air permit; (5) Renegotiations of power purchase agreements in anticipation of their expiration, approved by the Commission.

In accordance with MECO's preferred plan developed in IRP-3, MECO will rely upon a portfolio of demand-side and supply-side resources to meet the growing demand for electricity. This portfolio will consist of energy efficiency and load management DSM resources, renewable resources, DG resources, existing and future utility firm capacity generation, existing firm capacity non-utility generation, and potential firm capacity non-utility generation.

A portfolio approach to capacity planning is necessary because of the uncertainties associated with each type of resource. For example, the economic attractiveness of energy efficiency DSM measures is a function of actual fuel prices and tax credits, which may be affected by federal legislation to extend the "sunset date", the date at which the tax credits will no longer be available. For load management DSM programs, there is uncertainty as to when regulatory approval will be received and the rate at which customers will choose to participate in the programs. Central station and distributed generation, whether utility or non-utility, are subject to the uncertainties of the permitting process. Furthermore, the actual impacts of customer-owned DG such as CHP will be dependent upon actual and projected fuel prices and customer acceptance of the technology. Renewable energy projects are subject to the uncertainty of community acceptance, as demonstrated by Hawaiian Electric Company, Inc.'s ("HECO") experience in attempting to implement a wind energy project above Kahe on Oahu in 2005. Therefore, by pursuing an array of demand-side and supply-side resources with a portfolio approach, some of the uncertainty can be mitigated because the successes of some resources can offset the lower productivity of other resources.

1.7.2 Firm Capacity Needed in 2011

In MECO's IRP-2 Report, filed on May 31, 2000 in Docket No. 99-0004, MECO indicated in its Preferred Plan that following the installation of the second dual-train combined cycle ("DTCC") consisting of Maalaea Units 17, 18 and 19, additional increments of firm capacity would be needed in 2007 and 2010. These installation dates were predicated on an ending of the MECO-HC&S PPA on December 31, 2001. The IRP-2 Preferred Plan identified these additional increments of firm capacity as 20.8 MW-net simple cycle combustion turbines. Since, due to space constraints, no additional generating units could be installed at the existing Maalaea Generating Station following the completion of the second DTCC, these increments of firm capacity would be installed at MECO's new Waena site, which was_purchased by MECO from Alexander & Baldwin on November 26, 1996 following Commission approval of the purchase in Decision and Order No. 14675, issued on May 10, 1996 in Docket No. 96-0039. . On July 7, 2000, the Maui County Council approved MECO's Change in Zoning application (to change the zoning from Agricultural to Heavy Industrial) for the Waena Generating Station and the bill was subsequently approved by the Mayor on July 13, 2000.

Based on (a) MECO's IRP-2 Preferred Plan, which identified the first unit at its Waena Generation Station as a 20.8 MW-net simple cycle combustion turbine; (b) MECO's IRP-2 Preferred Plan that indicated that the first Waena generating unit would be needed in 2007; and (c) the long lead time needed to install a new generating unit, air permitting activities for the first Waena generating unit were initiated in 2000. (Air permitting activities are the first critical path components in the schedule to install a generating unit.) A Prevention of Significant Deterioration/Covered Source ("PSD/CS") permit application (i.e., air permit application), was submitted to the State of Hawaii Department of Health ("DOH") on December 5, 2002.

MECO's IRP-2, 2004 Evaluation Report, was submitted to the Commission on April 30, 2004 in Docket No. 99-0004. The purpose of the Evaluation Report was to provide an update of the recent developments and events, including changes in forecasts, since the filing of MECO's IRP-2 plan that may or may not have significant impact on MECO's IRP plan. The report documented that:

> The HC&S PPA will remain in effect through December 31, 2007, and from year to year thereafter, subject to termination on or after the end of the day on December 31, 2007, on not less than two years prior written notice by either party.

In addition, it was also reported that Distributed Generation/Combined Heat and Power ("DG/CHP") projects were being proposed that could reduce the total system demand.

For these reasons, MECO's IRP-2, 2004 Evaluation report updated the MECO IRP-2 resource plan to reflect a 2010 installation date for the Waena Unit 1, 20.8 MW-net simple cycle combustion turbine and a 2013 installation date for the Waena Unit 2, 20.8 MW-net simple cycle combustion turbine at the new Waena Generating Station located in central Maui as determined by the Maui capacity planning criteria. However, with the uncertainty in the utility DG/CHP program, MECO would continue long lead-time planning activities for the Waena Unit 1 generating unit to maintain the flexibility of a 2007 commercial operation date and support the possibility of the earlier need-date.

On April 29, 2005, MECO submitted to the Commission its IRP-2, 2005 Evaluation Report. The purpose of the Evaluation Report was to provide an update of the recent developments and events, including changes in forecasts, since the filing of MECO's IRP-2 plan and the subsequent IRP-2, 2004 Evaluation Report that may or may not have significant impact on MECO's IRP plan. With regards to the Waena Unit 1 installation, the report stated:

> In 2009 MECO is currently planning to install Waena 1 (W1), a simple-cycle combustion turbine firing diesel fuel oil, at the new Waena Generating Station located in central Maui. Although the capacity need date for Waena 1 occurs earlier in 2008 to meet forecasted peaking/cycling demands on the Maui electrical system due to future load growth, MECO estimates that it would be unable to receive the necessary PSD/CS Permit from DOH in time to support a 2008 installation date. MECO currently estimates receiving the PSD/CS Permit in April 2007, which supports an installation date in 2009. To ensure continued system reliability in the time period from the initial capacity need date (2008) until the actual unit installation date (2009), MECO will implement mitigation measures similar to those discussed in MECO's Adequacy of Supply Letter recently filed with the PUC on March 15, 2005. MECO plans on submitting an Application to the PUC later this year for the approval to commit funds for the purchase and installation of Waena 1. This Application will provide the project description, justification, schedule, and estimated cost.
>
> Although MECO is currently planning to install Waena 1 in 2009, this date could be deferred depending on the outcome of current negotiations between HC&S and MECO concerning the existing HC&S PPA, which is due to expire at the end of 2007. If in fact, the Waena 1 capacity need date is deferred to some later date, MECO would make the appropriate changes to the Waena project schedule to correspond to that date.

Through negotiations with DOH in July 2005, MECO agreed to resubmit its air permit application with updates included in the Maalaea Unit 18 PSD/CS permit, which was approved on September 8, 2004. In compliance with this request, MECO resubmitted its air permit application in December 2005. On January 30, 2006, the DOH determined MECO's air permit application "complete" for the purposes of the Prevention of Significant Deterioration ("PSD") program, meaning that all information needed by DOH to review the application for PSD requirements was contained within the application.

As noted in Section 1.5.2, an agreement was reached between MECO and HC&S (June 28, 2005) not to issue a notice of termination of the PPA resulting in the termination of the PPA prior to the end of the day on December 31, 2011. With this non-termination agreement, the need date for new firm capacity that was intended to be supplied by the Waena Unit 1 unit was deferred from 2009 to 2011, based on forecasts for peak demand, energy efficiency DSM impacts, load management DSM impacts and CHP impacts in effect at that time.

MECO IRP-3 was filed with the Commission on April 30, 2007 in Docket No. 04-0077. In consideration of the IRP Framework, current trends in the electric utility environment, various forecasts, IRP objectives, results of the various analysis, selection and screening considerations of the Finalist Plans, and initial Advisory Group input, MECO's Preferred Integrated Resource Plan indicated that a block of firm capacity would be needed in 2011 and a second block of firm capacity would be needed in 2013. The timing of the need for the second block of capacity was based on the assumption that a 20.8 MW block of capacity would be installed in 2011 and the HC&S PPA would terminate at the end of 2011. MECO applied its capacity planning criteria to determine when additional generation capacity needed to be added to the system.

Similar to the agreement that occurred in June 2005, MECO and HC&S agreed on July 2, 2007 not to issue a notice of termination of the PPA resulting in termination of the PPA prior to the end of the day on December 31, 2014. Although this non-termination agreement had no impact on the 2011 need date for the first increment of firm capacity, it has impacted the need date of the second increment of firm capacity by deferring it from 2013 to 2015.

1.7.3 <u>Firm Capacity Needed in 2015</u>

As indicated in Section 1.5.2, with the agreement of HC&S on July 2, 2007 not to issue a notice of termination of the PPA resulting in termination of the PPA prior to the end of the day on December 31, 2014, MECO now anticipates the need for additional firm capacity (after Waena Unit 1) to be in the first quarter of 2015.

1.7.4 <u>Competitive Bidding for New Generating Capacity</u>

On December 8, 2006, the Commission issued Decision and Order ("D&O") No. 23121 in Docket No. 03-0372 pertaining to competitive bidding for new generation. This D&O contained the Commission's Competitive Bidding Framework ("CB Framework"). Section II.A.3 of the CB Framework requires that electric utilities that are subject to the CB Framework acquire new generating capacity through a competitive bidding process, unless a waiver is sought by the utility and the waiver is granted by the Commission. Although MECO has made substantial progress in obtaining the air permit for a simple cycle combustion turbine at its Waena site, MECO plans to solicit proposals, within the CB Framework, for new generating capacity in the 2011 timeframe and the 2015 timeframe via a competitive bidding process.

Section IV.B.2 of the CB Framework also states that the RFP issued by the electric utility shall identify any unique system requirements and important resource attributes of the type of capacity needed on the system. These attributes are discussed in Section 1.7.5 below.

On November 2, 2007, MECO submitted a request to the Commission to open a docket to receive filings, review approval requests, and resolve disputes, if necessary, related to MECO's proposed Request for Proposals ("RFP") for the firm capacity needs in 2011 and 2015. The November 2nd request also asked for approval of the contract with the selected Independent Observer. On December 6, 2007, the Commission issued Order No. 23872 approving MECO's requests to open a new docket (Docket No. 2007-0403) and approving the contract with the Independent Observer. The draft RFP is targeted for issuance in the second quarter of 2008.

1.7.5 <u>Attributes of Firm Capacity</u>

1.7.5.1 <u>Attributes for 2011 Increment of Capacity</u>

The attributes of the capacity needed in 2011 are described in Exhibit A of the MECO IRP-3 Stipulation between MECO and the Consumer Advocate, filed on April 30, 2007 in Docket No. 04-0077 ("MECO IRP-3 Stipulation") and are as follows:

<u>Nominal 20 MW Firm Capacity Resource in 2011</u> – Scope: Approximately 20 to 25 MW of firm generating capacity. The unit may be renewable or fossil-fueled, with a preference in resource evaluation for renewable energy. The unit must be capable of peaking or cycling duty where the unit can be started quickly (less than 30-minute startup time) and can cycle off-line at least once per day. When on-line, the unit shall be fully dispatchable from minimum to full load by the utility and shall be capable of load-following, providing frequency control and voltage support

according to standards to be determined by the utility. The unit must have black-start capability.

The attributes listed are in support of Hawaii's energy objectives, which include (per H.R.S §226-18(a)):

- Dependable, efficient, and economical statewide energy systems capable of supporting the needs of the people;
- Increased energy self-sufficiency where the ratio of indigenous to imported energy use is increased;
- Greater energy security in the face of threats to Hawaii's energy supplies and systems; and
- Reduction, avoidance, or sequestration of greenhouse gas emissions from energy supply and use.

1.7.5.2 Attributes for 2015 Increment of Capacity

The attributes of the capacity needed in 2015 are described in Exhibit A of the MECO IRP-3 Stipulation. In the MECO IRP-3 Stipulation, the need date is identified as 2013 based on the then-current planning assumption that termination the HC&S PPA could result in the loss of the HC&S capacity at the end of the day on December 31, 2011. However, as indicated above, an agreement between MECO and HC&S was reached to for HC&S to continue providing capacity at least until the end of the day on December 31, 2014. With this updated planning assumption, the need date for additional firm capacity was deferred from 2013 to 2015. The attributes needed for this increment of capacity, as stated in the MECO IRP-3 Stipulation are as follows:

Nominal 20 MW Firm Capacity Resource in 2015 – Scope: Approximately 20 to 25 MW of firm generating capacity. The unit may be renewable or fossil-fueled, with a preference in resource evaluation for renewable energy. The unit must be capable of peaking or cycling duty where the unit can be started quickly (less than 30-minute startup time) and can cycle off-line at least once per day. When on-line, the unit shall be fully dispatchable from minimum to full load by the utility and shall be capable of load-following, providing frequency control and voltage support according to standards to be determined by the utility. The unit must have black-start capability. Detailed specifications for the resource will be developed at the time the RFP is developed.

1.7.6 Appropriate Size of Capacity Blocks

As indicated above, MECO will be seeking blocks of 20 MW to 25 MW each for the 2011 and 2015 timeframes. With the anticipated load growth on the island of Maui, the need for capacity increases each year, as shown in Table 1.6-1. It is prudent to install a larger amount of capacity in 2011 to account for the load growth over the following 3 to 5 years, than to install several small increments of capacity on an annual basis for the following reasons:

- Large increment of capacity can account for unforeseen increases in forecasted demand.
- Large increment of capacity can offset energy efficiency and load management DSM impacts which may be unexpectedly lower than forecast.
- Large increment of capacity are designed to provide significant export power to the electric grid at the transmission level, as opposed to small increments of capacity (such as DG), which is sized to meet individual customer load or feed a distribution circuit.
- Larger increments of capacity provides for economies of scale, as determined in the IRP analysis.

1.7.7 Parallel Plan for Firm Capacity Needed in 2011

The Commission's CB Framework requires that new generating capacity be acquired through a competitive bidding process. As indicated earlier, MECO plans to employ a competitive bidding process to secure increments of firm capacity in the 2011 and 2015 timeframes.

Section II.D.2 of the CB Framework also requires the electric utility to develop a Parallel Plan, which would be implemented simultaneously with the selected bidder's project (assuming the winning bid is not the utility's bid). The utility's Parallel Plan would be terminated when there was reasonable assurance that the winning bidder's project will reach successful completion.

As indicated in Section VI.C. of the CB Framework, the requirement for the utility to pursue a parallel plan is triggered when the RFP process results in the selection of non-utility (third party) projects. Although an RFP for the next increment of firm capacity for the Maui system has not yet been issued as of the date of this AOS filing, because of long-lead time activities such as air permitting and engineering, MECO has and will continue to work toward the installation of a nominal 21 MW simple cycle combustion turbine at the Waena Generating Station in 2011. As indicated earlier, MECO has already made substantial progress in obtaining the air permit for such a generating unit. This project will serve as MECO's Parallel Plan.

Permitting activities for the Waena Unit 1 simple cycle combustion turbine are on-going. In August, September and October 2007, MECO submitted responses to DOH's March 2007 request for information and clarification in connection with the permit application. On December 18, 2007, MECO submitted a permit application revision to use biodiesel as the primary fuel with no. 2 fuel oil as the backup fuel. Further, MECO plans to submit an application sometime in the first half of 2008 requesting Commission approval for the Waena Unit 1 as its CB Framework Parallel Plan. In addition, preliminary engineering including site layout and configuration has commenced.

1.7.8 Parallel Plan for Firm Capacity Needed in 2015

MECO plans to commence with the parallel planning process in 2008 for the firm generating capacity acquired in the 2015 timeframe via a competitive bidding process.

1.8 Mitigation Measures for Reserve Margin Shortfalls

MECO plans to mitigate the RM shortfall in 2010, through one or more of the mitigation measures identified below, depending on the particular circumstances. These mitigation measures are as follows:

1.8.1 Maui Distributed Generation ("DG") and Dispatchable Standby Generation ("DSG")

Based on current capacity planning analysis, which was previously discussed in Section 1.6.2, MECO may need a small amount of additional generating capacity in 2010 in order to avoid a reserve capacity deficit based on a 20% minimum reserve margin shortfall, as shown in Table 1.6.1-1, that may occur prior to the installation of the planned block of capacity in 2011.[6] For these small

[6] In 2010, based on forecasts for peak demand, energy efficiency DSM impacts, load management DSM impacts and CHP impacts in effect at this time, Maui's reserve margin is anticipated to fall below the 20% minimum reserve margin guideline (18%) in its capacity planning criteria. MECO does not plan to advance the need date for firm generating capacity to 2010 based on its reserve margin being less than 20% because MECO fully expects to be able to meet

increments of capacity shortage and with sufficient lead time, DG units and DSG could be installed to mitigate or remove these RM shortfalls. DG units can be either permanent or temporary installations. If the DG units are used on a temporary basis, then these temporary DG units could mitigate the RM shortfalls until permanent capacity is installed. DSG is anticipated to be a customer-owned resource. Therefore, the DSG may not provide the identical operating characteristics and system planning value as MECO-owned DG, but it still has attractive potential economic and other benefits for both the utility and the customer.

Due to the potential benefits DG and DSG could provide to the MECO system, MECO conducted an investigation of the amount of DG practicable for development by MECO over the next several years. The investigation lead to the development of an internal report ("Maui Distributed Generation Assessment") that included: permanent or temporary DG installations, Dispatchable Standby Generation ("DSG"), operational capacity considerations, and cost considerations. The report concludes that there are four (4) potential sites for possible DG projects. These sites are located at utility-owned substations and have the potential for approximately 6.6 MW of permanent DG resources. The report also notes that there may also be opportunities for some amount of customer-owned DSG. A copy of this report was filed with the PUC on December 12, 2007

1.8.2 Optimize Unit Overhaul Schedule

MECO will optimize its unit overhaul schedule to minimize any LSC margin shortfall by matching a unit's outage with the available reserve capacity at that time.

1.8.3 Deviation from Standard Maintenance Practices

Combined-Cycle Unit Overhaul – MECO will modify its combined-cycle unit overhaul procedure to minimize the outage capacity for that unit. The exhaust bypass option of MECO's Maalaea DTCC No. 1 (Maalaea Units 14, 15, and 16) will be used to allow for the possible operation of the combustion turbine ("CT") (if needed) in simple-cycle mode while certain planned maintenance is being performed on the heat recovery steam generators and steam turbine generator (Maalaea Unit 15). While not the ideal outage method, this modified maintenance

demand, even with a unit on maintenance and with the largest remaining available unit forced out of service at the time of the system peak in that year.

procedure will allow, if the situation warrants, the possible use of an additional 20 MW from the CT.

1.8.4 Coordination with HC&S

MECO will coordinate closely with HC&S for the delivery of supplemental power, if needed, as described in the Purchase Power Agreement under Section II D.

1.8.5 Public Communications Campaign

MECO may request voluntary customer curtailment of demand during LSC margin shortfall conditions.

2.0 Lanai Division

2.1 Peak Demand and System Capability in 2008 - 2010

Lanai's 2007 system peak occurred on October 17, 2007 and was 5,460 kW (gross). Lanai had a 2007 reserve margin of approximately 72%. Attachment 1, Table 2, also shows the expected reserve margins over the next three years, based on the MECO 2008-2015 Sales and Peak Forecast dated July 2007.

2.2 Lanai Division Capacity Planning Criteria

The following criterion is used to determine the timing of an additional generating unit for the Lanai Division and the Molokai Division:

New generation will be added to prevent the violation of any one of the rules listed below where "units" mean all units and firm capacity suppliers physically connected to the system, and "available unit" means an operable unit not on scheduled maintenance.

1. *The sum of the normal top load ratings of all units must be equal to or greater than the system peak load to be supplied.*

2. *With no unit on maintenance, the sum of the reserve ratings of all units minus the reserve rating of the largest available unit must be equal to or greater than the system peak to be supplied.*

3. *With a unit on maintenance:*

a) *The sum of the reserve ratings of all units minus the reserve rating of the largest available unit must be equal to or greater than the daytime peak load to be supplied.*

b) *The sum of the reserve ratings of all units must be equal to or greater than the evening peak load to be supplied.*

2.3 Lanai Combined Heat and Power Project

On June 16, 2006, MECO executed a CHP agreement with Castle & Cooke Resorts for the installation of an 884 kW (net including electric chiller offset and auxiliary loads) CHP system at the Four Seasons Resort Lanai at Manele Bay. The CHP agreement was filed for approval by the Commission on July 14, 2006, in Docket No. 2006-0186. MECO provided additional information in support of its application to the Consumer Advocate, and the Consumer Advocate filed its final statement of position on January 18, 2007. MECO filed its response to the Consumer Advocate's statement of position on February 15, 2007, reiterating its position that the proposed MECO CHP System presents a reasonable and justifiable proposal to meet Lanai's need for additional generating capacity. On November 9, 2007, MECO and the Consumer Advocate filed a Stipulation Regarding Hearing and Commission Approval, wherein the parties recommended that the Commission approve the Lanai CHP project. On December 17, 2007, MECO filed responses to the Commission's information requests that were issued on November 15, 2007, and on January 30, 2008, MECO filed its response to a further Commission information request. Should the Commission approve the CHP agreement, MECO projects the CHP system to be placed in service in the December 2008 to January 2009 timeframe.

On December 21, 2007, the State of Hawaii Department of Heath issued to MECO the Noncovered Source Permit (NSP No. 0668-01-C) for the Manele Bay CHP project. The NSP has an issuance date of December 21, 2007 and an expiration date of December 20, 2012. Aside from Commission approval of the CHP agreement, MECO has obtained all major discretionary approvals to proceed with the project.

MECO's CHP development efforts with Castle & Cooke Resorts were initiated within the context of MECO's existing service contract ("Service Contract") with Castle & Cooke Resorts, filed with the Commission in Docket No. 03-0261. MECO has reviewed D&O 22248 in Docket No. 03-0371, as clarified by Order No. 22375, and is continuing to pursue this CHP project based on its interpretation of the D&O and the justifications to pursue CHP that were presented in Docket No. 03-0261.

The Service Contract contemplated the addition of a CHP system at the Manele Bay Hotel, whether installed by MECO or a non-utility vendor, at a date closer to the projected need date for additional firm capacity on Lanai. The need date for additional firm capacity is projected to be June 2008, under the base planning scenario for Lanai. In this base planning scenario, the aggregate capacity of Miki Basin EMD units 1-6 was reduced from 6,000 kW to 5,000 kW on December 31, 2006, because a condition assessment performed by an outside consultant indicated that it would be appropriate, for capacity planning purposes, to rely on less than their full rated capacity based on the ages and condition of the units (See Attachment 1, Table 2, Note VI.). With the addition of the CHP system at Manele Bay projected to have an in service date in the December 2008 to January 2009 timeframe, MECO is aware that Lanai may experience a LSC margin shortfall in June 2008, when one of the 2.2 MW Caterpillar units (LL-8) is on planned maintenance. MECO plans to implement mitigation measures to avoid shedding load in the event of the loss of the largest unit (unit LL-7, also a 2.2 MW Caterpillar unit) during the day peak. In addition, unit LL-7 is scheduled to be on planned maintenance in October 2008. However, MECO has determined that the maintenance of unit LL-7 can be deferred and performed in January 2009 without undue risk to the unit. If the Manele Bay CHP is in operation in January 2009, the system will not be at risk when LL-7 is on maintenance. By applying mitigation measures and deferring the maintenance of unit LL-7, MECO will be able to meet electric load requirements on Lanai, satisfy the energy cost savings objectives of its Service Contract with Castle & Cooke Resorts. If the operation of the Manele Bay CHP is delayed beyond January 2009, MECO would again implement mitigation measures to avoid shedding load in a LSC margin shortfall.

The addition of the Manele Bay CHP unit and the planned as-available 1.2 MW photovoltaic array on Lanai will present operational challenges on existing units at Miki Basin. Interconnection and protection studies will be performed to identify the design and operational considerations for the integration of these projects into the Lanai system.

3.0 Molokai Division

3.1 Peak Demand and System Capability in 2008 - 2010

Molokai's 2007 system peak occurred on November 7, 2007 and was 6,350 kW (gross). Molokai had a 2007 reserve margin of approximately 89%. Attachment 1, Table 2, also shows the expected reserve margins over the next three years, based on the MECO 2008-2015 Sales and Peak Forecast dated July 2007.

3.2 Molokai Division Capacity Planning Criteria

Molokai Division's capacity planning criteria are identical to those of the Lanai Division. See Section 2.2 above, Lanai Division Capacity Planning Criteria.

4.0 Conclusion

In consideration of the above, MECO has sufficient capacity to meet the forecasted loads on the islands of Maui, Lanai and Molokai for the next three years. Although, MECO may not, at times, have sufficient capacity on the Maui system to cover for the loss of the largest unit, MECO will implement appropriate mitigation measures to overcome the insufficient reserve capacity situation.

The Maui Division needs additional firm generating capacity in the 2011 timeframe. This is consistent with the determination made to date in its currently on-going IRP-3 process. MECO will comply with the requirements of the Commission's Competitive Bidding Framework in order to acquire that additional firm capacity.

Very truly yours,

Edward J. Reinhardt

Attachments

cc: Division of Consumer Advocacy (with Attachments)

Table 1
Maui Adequacy of Supply

	With Small CHP[I]				
		Without Future DSM (Includes Acquired DSM)[II]		With Future DSM (Includes Acquired DSM)[III]	
Year	System Capability at Annual Peak Load[IV] (kW) [A]	System Peak[V] (kW) [B]	Reserve Margin (%) [[A-B] / B]	System Peak[V] (kW) [C]	Reserve Margin (%) [[A-C] / C]
Maui Division (Net Generation)					
Recorded					
2007	260,300 [VI]	204,400 [VII]	27%	N/A	N/A
Future					
2008	262,300 [VIII]	215,500	22%	212,700 [IX]	23%
2009	262,300	222,200	18%	216,800	21%
2010	262,300	229,000	15%	221,100	19%
2011	283,500 [X]	233,100	22%	223,100	27%
2012	283,500	238,900	19%	225,800	26%
2013	283,500	243,200	17%	228,100	24%
2014	283,500	247,900	14%	231,200	23%
2015	288,700 [XI]	253,100	14%	234,900	23%
Maui Division (Gross Generation)[XII]					
Recorded					
2007	265,700 [VI]	209,300 [VII]	27%	N/A	N/A
Future					
2008	267,700 [VIII]	220,600	21%	217,800 [IX]	23%
2009	267,700	227,500	18%	221,900	21%
2010	267,700	234,400	14%	226,400	18%
2011	289,200 [X]	238,600	21%	228,400	27%
2012	289,200	244,600	18%	231,200	25%
2013	289,200	249,000	16%	233,500	24%
2014	289,200	253,800	14%	236,700	22%
2015	294,800 [XI]	259,100	14%	240,500	23%

Notes – Table 1:

(I) With Small CHP Market: Forecasted system peaks include reductions for CHP impacts.[1]

(II) System Peaks (Without Future Peak Reduction Benefits of DSM Programs):
Implementation of full-scale energy efficiency DSM programs began in the second half of 1996 following Commission approval of the programs. The forecasted system peak values for the years 2008-2015 include the actual peak reduction benefits acquired in 1996-2006 and also include the estimated peak reduction benefits acquired in 2007, as well as peak reduction benefits of Rider M and T customer contracts, and CHP impacts.

(III) System Peaks (With Future Peak Reduction Benefits of DSM Programs).
The forecasted System Peaks for 2008-2015 include the peak reduction benefits of energy efficiency DSM programs (acquired and future) and peak reduction benefits of Rider M and T customer contracts, and CHP impacts.

(IV) The net reserve ratings of the units are used in the determination of the Maui system capability. In addition, the Maui Division system capability includes 16,000 kW (which includes 4,000 kW of system protection capacity) from HC&S. 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.

(V) The 2008 - 2015 annual forecasted system peaks are based on MECO's July 2007, 2007-2015 Sales and Peaks Forecast and includes reductions for CHP impacts. The Maui annual forecasted system peak is expected to occur in the month of August.

(VI) Maalaea Unit 13, a Mitsubishi 12.34 MW (net) diesel engine generator, suffered equipment failure on December 9, 2005. Corrective maintenance measures were performed to repair the unit, and the Maalaea Unit 13 returned to operation on July 9, 2007. The year-end system capability was 262,300 kW (net).

On June 9, 2006, Kaheawa Wind Power ("KWP") completed construction of a 30 MW wind farm. MECO and KWP executed a new purchase power agreement ("PPA") on December 3, 2004. MECO submitted an Application on December 16, 2004 for approval of the PPA. On March 18, 2005, the Commission issued D&O No. 21701 approving the PPA. The installation of this wind resource will not affect the system capability, because the wind resource is an as available resource, which is not dispatchable and cannot provide given amounts of power at scheduled times.

[1] CHP impacts are from a CHP forecast dated January 9, 2007. These impacts are at system level based on a T&D loss factor of 5.96%. For capacity planning analysis, an availability factor is also included to account for periods when the utility CHP is unavailable due to forced outage and maintenance.

On September 22, 2006, Makila Hydro, LCC ("Makila"), completed construction of a 500 kW hydro-electric facility and commenced providing energy to the Maui system. MECO and Makila executed a PPA on May 10, 2005. MECO submitted an application to the Commission on June 28, 2005, which among other things, requested approval of the PPA. On May 10, 2006, the Commission issued Decision & Order No. 22460, approving the PPA. The installation of this hydro resource does not affect the system capability, because the hydro resource is an as available resource, which is not dispatchable and cannot provide given amounts of power at scheduled times. Makila Hydro experienced equipment failure and became unavailable on October 15, 2006. Makila Hydro anticipates repairs to be completed by the second quarter of 2008 and resume energy production.

Maalaea Unit 18, steam turbine generator (Phase III of a nominal 56,780 kW (net) dual train combined-cycle unit), was placed in service on October 27, 2006.

MECO filed a letter with the Commission in Docket No. 6616 (HC&S), on July 25, 2007, which informed the Commission that MECO and HC&S agreed on July 2, 2007 not to issue a notice of termination of the PPA resulting in termination of the PPA prior to the end of the day on December 31, 2014.[2]

(VII) The actual 2007 recorded system peak was 209,300 kW (gross) which is equivalent to 204,400 kW (net).

(VIII) Includes the Hana generating units as firm capacity. Hana communications and control project to be completed in 2008, enabling the Hana units to be dispatchable distributed generation.

(IX) Includes a reduction in system peak load due to the implementation of planned Commercial and Industrial Direct Load Control ("CIDLC") and Residential Direct Load Control ("RDLC") Load Management DSM Programs developed in MECO's IRP-2 Report. Partial Load Management DSM Program benefits are forecasted to start in 2008, with full-scale impacts forecasted to start in 2009.

(X) Waena Unit 1, a 21,180 kW (net) combustion turbine generator is scheduled to be placed in service in 2011, pending the result of the MECO competitive bidding process and successive permitting and construction scheduling.

(XI) Capacity planning assumption that the HC&S contract is terminated on December 31, 2014.

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[2] Previously, in a letter dated June 28, 2005, MECO and HC&S had agreed that neither company would give written notice of termination resulting in a termination of the PPA prior to the end of the day on December 31, 2011. MECO filed the June 28, 2005 letter with the Commission on July 27, 2005 in Docket No. 6616.

For capacity planning purposes, a 21,180 kW (net) combustion turbine generator is scheduled to be installed to replace the lost capacity from HC&S. The actual type and size of this capacity will be determined through a competitive bidding process.

(XII) The Maui Division Gross Generation data is provided here for comparative purposes.

Table 2
Lanai and Molokai Adequacy of Supply

		Without Future DSM (Includes Acquired DSM)[I]		With Future DSM (Includes Acquired DSM)[II]	
Year	**System Capability at Annual Peak Load[III] (kW) [A]**	**System Peak[IV] (kW) [B]**	**Reserve Margin (%) [[A-B] / B]**	**System Peak[IV] (kW) [C]**	**Reserve Margin (%) [[A-C] / C]**
Lanai Division (Gross Generation)					
Recorded					
2007	9,400 [V]	5,460	72%	N/A	N/A
Future					
2008	9,400	6,311	49%	N/A	N/A
2009	10,284 [VI]	6,513	58%	N/A	N/A
2010	10,284	6,655	55%	N/A	N/A
Molokai Division (Gross Generation)					
Recorded					
2007	12,010 [VII]	6,350	89%	N/A	N/A
Future					
2008	12,010	6,363	89%	N/A	N/A
2009	12,010	6,395	88%	N/A	N/A
2010	12,010	6,427	87%	N/A	N/A

Notes – Table 2:

(I) System Peaks (Without Future Peak Reduction Benefits of DSM Programs):
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

2008-2010 include the actual peak reduction benefits acquired in 1996-2006 and also include the estimated peak reduction benefits acquired in 2007.

(II) System Peaks (With Future Peak Reduction Benefits of DSM Programs):
Currently no future DSM impacts are forecasted for Lanai or Molokai.

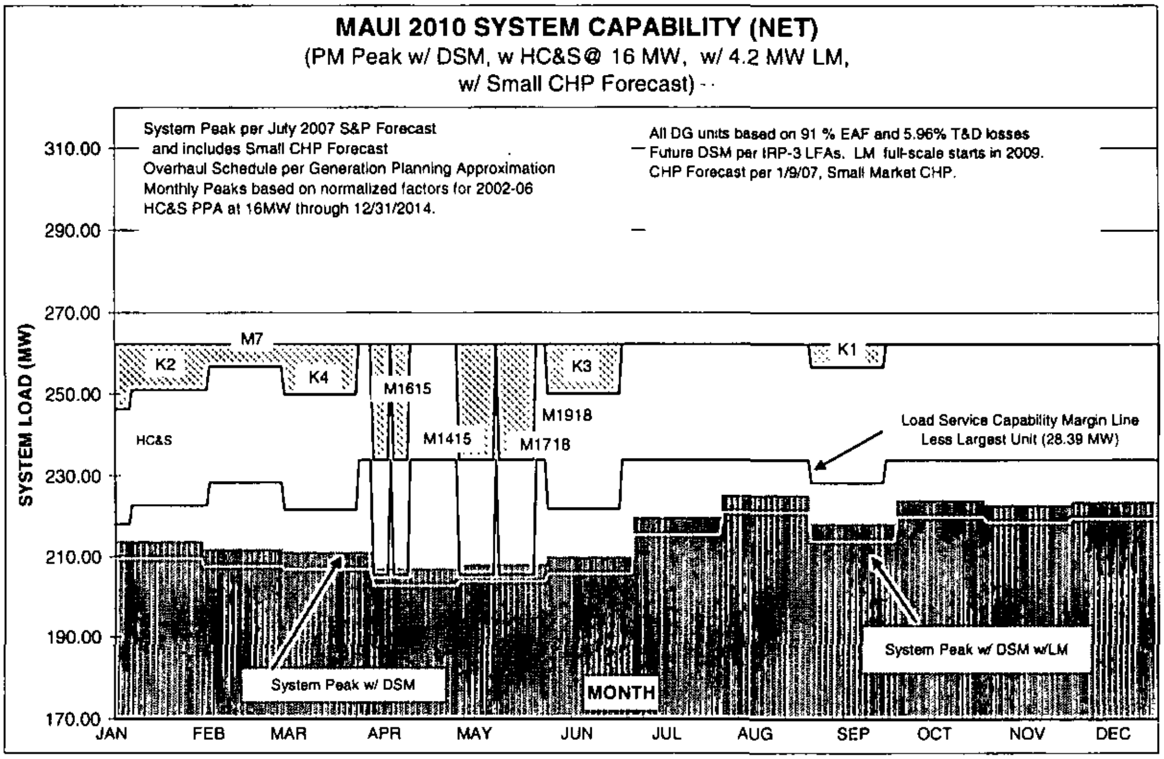
(III) The gross reserve ratings of the units are used in the determination of the Lanai and Molokai system capabilities. All unit projected retirement dates are planned for December 31 of the designated year unless otherwise specified. When the system capability at the time of the system peak differs from the year-end system capability, an applicable note will indicate the year-end system capability.

(IV) The 2008 - 2010 annual forecasted system peaks are based on MECO's 2007-2015 Sales and Peaks Forecast dated July 2007. The Lanai and Molokai annual forecasted system peaks are expected to occur in the months of December and January, respectively.

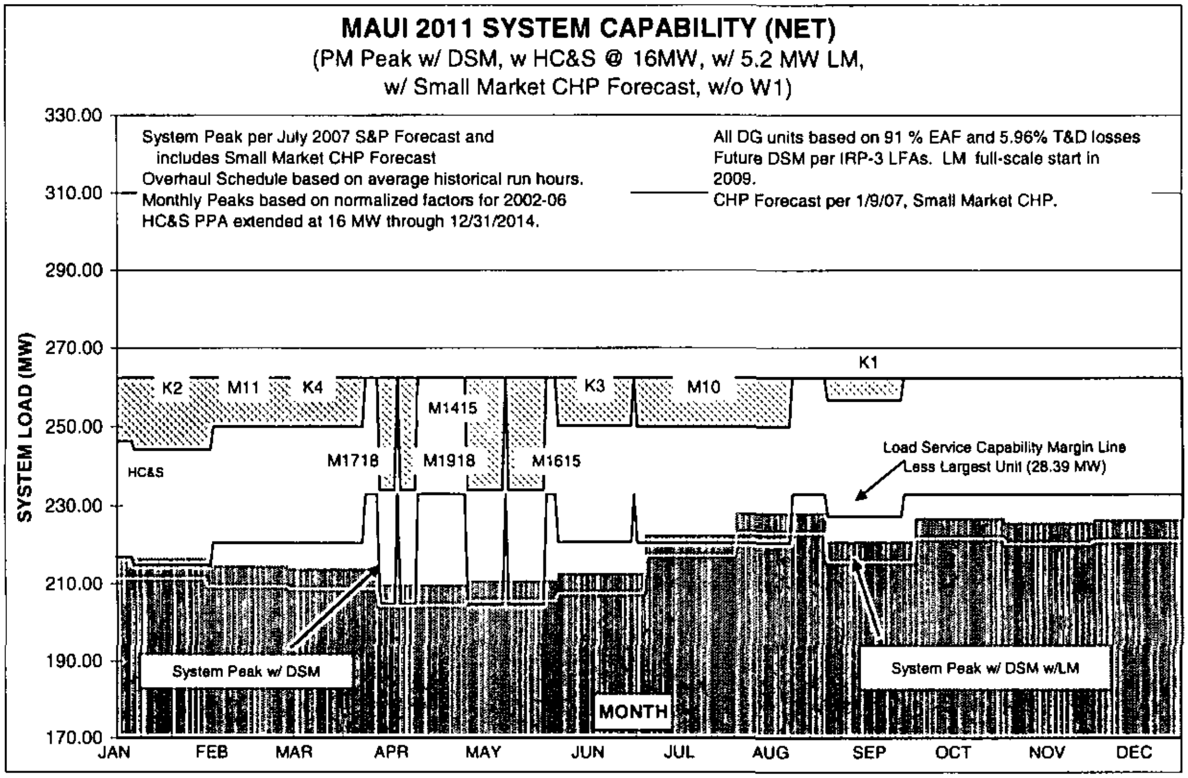
(V) Miki Basin Units LL-1 to LL-6 (six,1,000 kW diesel engine-generator units totaling 6,000 kW) were converted to peaking status at the end of 2006, and as such, can be relied on for 5,000 kW of capacity to the Lanai system.

(VI) MECO has signed an agreement with Castle & Cooke Resorts for the installation of an 844 kW (net including electric chiller offset and auxiliary loads) CHP system at the Manele Bay Hotel in the first quarter of 2009. Refer to Section 2.3 for further details

(VII) Palaau Units 1 and 2 (two 1,250 kW Caterpillar units), and Palaau Units 3, 4, 5 and 6 (four 970 kW Cummins units) operate in peaking service. Because of the age and operating history of these units, MECO includes one Caterpillar unit and two Cummins units (1,250 + 970 + 970 = 3,190 kW) towards firm capacity for the Molokai system.



Month (1)	System Peak w/ DSM w/ Riders w/ Small Mkt CHP (MW) (2)	System Cap (MW) (3)	Maint (MW) (4)	Reserve (MW) (5)=(3)-(4)-(2)	% Reserve (Less Maint) (5) / (2)	Lrgst Avail (MW) (7)	LSC Diff (MW) (8) = (5) - (7)	LSC Diff + LM (impact) (MW) (8) + 4.2 MW
JAN	213.7	262.34	16.0	32.6	15%	28.39	4.2	8.4
FEB	211.8	262.34	11.3	39.3	19%	28.39	10.9	15.1
MAR	211.1	262.34	12.4	38.9	18%	28.39	10.5	14.7
APR	207.0	262.34	28.4	27.0	13%	28.39	-1.4	2.8
MAY	208.0	262.34	28.4	25.9	12%	28.39	-2.5	1.7
JUN	209.9	262.34	12.2	40.3	19%	28.39	11.9	16.1
JUL	219.6	262.34	0.0	42.8	19%	28.39	14.4	18.6
AUG	225.1	262.34	0.0	37.2	17%	28.39	8.8	13.0
SEP	218.0	262.34	5.6	38.7	18%	28.39	10.3	14.5
OCT	223.9	262.34	0.0	38.4	17%	28.39	10.0	14.2
NOV	222.7	262.34	0.0	39.7	18%	28.39	11.3	15.5
DEC	223.4	262.34	0.0	38.9	17%	28.39	10.5	14.7



Month (1)	System Peak w/ DSM w/ Riders w/ Small Mkt CHP (MW) (2)	System Cap (MW) (3)	Maint (MW) (4)	Reserve (MW) (5)=(3)-(4)-(2)	% Reserve (Less Maint) (5) / (2)	Lrgst Avail (MW) (7)	LSC Diff (MW) (8) = (5) - (7)	LSC Diff + LM (impact) (MW) (8) + 5.2 MW
JAN	216.5	262.34	18.1	27.7	13%	28.39	-0.7	4.5
FEB	214.5	262.34	18.1	29.7	14%	28.39	1.3	6.5
MAR	213.9	262.34	12.4	36.1	17%	28.39	7.7	12.9
APR	209.6	262.34	28.4	24.3	12%	28.39	-4.1	1.1
MAY	210.8	262.34	28.4	23.2	11%	28.39	-5.2	0.0
JUN	212.6	262.34	12.3	37.4	18%	28.39	9.0	14.2
JUL	222.5	262.34	12.3	27.5	12%	28.39	-0.9	4.3
AUG	228.2	262.34	12.3	21.8	10%	28.39	-6.6	-1.4
SEP	220.9	262.34	5.6	35.8	16%	28.39	7.4	12.6
OCT	226.9	262.34	0.0	35.4	16%	28.39	7.1	12.3
NOV	225.6	262.34	0.0	36.7	16%	28.39	8.4	13.6
DEC	226.4	262.34	0.0	36.0	16%	28.39	7.6	12.8

Maui Unit Ratings

As of December 31, 2007

Units	Gross (MW)		Net (MW)	
	Reserve	NTL[I]	Reserve	NTL[I]
M1	2.50	2.50	2.50	2.50
M2	2.50	2.50	2.50	2.50
M3	2.50	2.50	2.50	2.50
X1	2.50	2.50	2.50	2.50
X2	2.50	2.50	2.50	2.50
M4	5.60	5.60	5.51	5.51
M5	5.60	5.60	5.51	5.51
M6	5.60	5.60	5.51	5.51
M7	5.60	5.60	5.51	5.51
M8	5.60	5.60	5.48	5.48
M9	5.60	5.60	5.48	5.48
M10	12.50	12.50	12.34	12.34
M11	12.50	12.50	12.34	12.34
M12	12.50	12.50	12.34	12.34
M13[II]	12.50	12.50	12.34	12.34
M14/15/16[III]	58.00	58.00	56.78	56.78
M17/18/19[III]	58.00	58.00	56.78	56.78
Maalaea GS	212.10	212.10	208.42	208.42
K1	5.90	5.00	5.62	4.71
K2	6.00	5.00	5.77	4.76
K3	12.70	11.50	12.15	10.98
K4	13.00	12.50	12.38	11.88
Kahului GS	37.60	34.00	35.92	32.33
HC&S[IV]	16.00	12.00	16.00	12.00
Hana 1[V]	-	-	-	-
Hana 2[V]	-	-	-	-
Maui System	265.70	258.10	260.34	252.75

Notes:

(I) NTL = Normal Top Load

(II) Maalaea Unit 13, a Mitsubishi 12.34 MW (net) diesel engine generator, suffered a catastrophic equipment failure on December 9, 2005. Corrective maintenance measures were performed to repair the unit, and the Maalaea Unit 13 was returned to operation on July 9, 2007

(III) The NTL rating for long-term capacity planning purposes for the two Maalaea Dual Train Combined Cycle units, Maalaea Unit 14/15/16 and Maalaea Unit 17/18/19, is each 56.78 MW (net). This NTL rating for Maalaea Unit 14/15/16 and Maalaea Unit 17/18/19 reflect the estimated output of the generating units provided in previous reports. MECO conducted a "capability test" for both of the Dual Train Combined Cycle units in September 2007. In those tests, Maalaea Unit 14/15/16 indicated a capability of 55.25 MW (gross) and 54.18 MW (net), and Maalaea Unit 17/18/19 indicated a capability of 55.89 MW (gross) and 54.58 MW (net) based on the conditions of the test at that time. In light of these recent test results, MECO is further examining the actual NTL capability of these units. Until such examination is complete, for purposes of long-term capacity planning and this Adequacy of Supply report, the previously reported capability of 56.78 MW (net) is being used.

(IV) All values for HC&S are net to the system. The reserve ratings include an additional 4.0 MWs of system protection capacity.

(V) Units located at Hana Substation No. 41. In 2007, a communication and controls project commenced and is scheduled to be completed in the first half of 2008. This project will provide MECO with the means to operate the Hana generators in parallel to the system and as emergency units. These units will also have the capability to be indirectly, remotely controlled and automatically brought on line. With the completion of the project anticipated in 2008, the Hana units have been designated as firm capacity and are included in the total reserve rating of the Maui system capability starting in 2008.

Lanai Unit Ratings

As of December 31, 2007

Units	Gross (kW)	
	Reserve	NTL(I)
LL-1 (VI)	1,000	1,000
LL-2 (VI)	1,000	1,000
LL-3 (VI)	1,000	1,000
LL-4 (VI)	1,000	1,000
LL-5 (VI)	1,000	1,000
LL-6 (VI)	1,000	1,000
LL-7	2,200	2,200
LL-8	2,200	2,200
Miki Basin GS	9,400	9,400

(VI) Miki Basin Units LL-1 to LL-6 (six,1,000 kW diesel engine-generator units totaling 6,000 kW) were converted to peaking status at the end of 2006, and as such, can be relied on for 5,000 kW of capacity to the Lanai system.

Molokai Unit Ratings

As of December 31, 2007

Units	Gross (kW)	
	Reserve	NTL[I]
P-1[VII]	1,250	1,250
P-2[VII]	1,250	1,250
P-3[VII]	970	970
P-4[VII]	970	970
P-5[VII]	970	970
P-6[VII]	970	970
Solar CT	2,220	2,220
P-7	2,200	2,200
P-8	2,200	2,200
P-9	2,200	2,200
Palaau GS	12,010	12,010

(VII) Palaau Units 1 and 2 (two 1,250 kW Caterpillar units), and Palaau Units 3, 4, 5 and 6 (four 970 kW Cummins units) operate in peaking service. Because of the age and operating history of these units, MECO includes one Caterpillar unit and two Cummins units (1,250 + 970 + 970 = 3,190 kW) towards firm capacity for the Molokai system.

SENSITIVITY ANALYSIS: BlueEarth Biofuels, LLC

BlueEarth Biofuels, LLC ("BEB") has proposed the construction and operation of a biofuel production plant on the island of Maui. There is uncertainty as to the timing of the installation of the plant and the electrical demand of the plant. Therefore, the current sales and peak forecast does not reflect the anticipated demand from the plant.

A preliminary scenario calls for construction of the plant to be done in three phases, with the first phase to be completed in 2010. A preliminary estimate is for Phase 1 is to increase the Maui demand by 2.5 MW. Phase 2, which may be completed by 2011, may increase the Maui demand by another 2.5 MW to a total of 5.0 MW. Phase3, which may be completed by 2012, may increase the Maui demand by an additional 2.5 MW for a total of 7.5 MW.

In this sensitivity analysis, a higher peak demand attributable to the three-phase installation and operation of the new biofuel plant was considered.

A comparison of the peak demand forecast for the base and sensitivity scenario (with biofuel plant) is shown in the following table.

Table A4-1

Year	Forecast System Peak Demand without DSM and CHP Impacts, MW-Net	Forecast Future and Acquired DSM Impacts, MW-Net	Forecast Small Market CHP Impacts, MW-Net	Forecast Impacts of Load Management DSM, MW Net	Forecast System Peak Demand with Peak Reduction Benefits of DSM and CHP, MW-Net	BlueEarth Biofuel, LLC Load Impact, MW-Net	Forecast System Peak Demand with Peak Reduction Benefits of DSM and CHP, and Added Load from Biofuel Plant MW-Net
2008	226.0	11.3	0.9	1.1	212.7	0.0	212.7
2009	233.1	12.2	1.3	2.7	216.8	0.0	216.8
2010	240.4	13.3	1.8	4.2	221.1	2.5	223.6
2011	244.5	14.4	1.8	5.2	223.1	5.0	228.1
2012	249.7	15.1	1.8	7.0	225.8	7.5	233.3
2013	253.4	15.7	1.8	7.8	228.1	7.5	235.6
2014	257.6	16.5	1.8	8.1	231.2	7.5	238.7
2015	262.1	17.1	1.8	8.3	234.9	7.5	242.4

The increase in overall demand due to the addition of the biofuel plant will directly impact the capacity need on the Maui system. The following table shows the increase in LSC margin shortfall due to the biofuel plant, assuming no new firm capacity is added to the system.

Table A4-2

Year	Forecast Peak Demand, MW-net	Total Firm Capacity on MECO System, MW-net	Largest Load Service Capability Margin Shortfall (Rule 1), without Biofuel Plant MW-net	Largest Load Service Capability Margin Shortfall (Rule 1), with Biofuel Plant MW-net
2008	212.7	262.3	0.0	0.0
2009	216.8	262.3	0.0	0.0
2010	221.1	262.3	0.0	-0.8
2011	223.1	262.3	-1.4	-6.4
2012	225.8	262.3	-4.8	-11.3
2013	228.1	262.3	-6.1	-13.6
2014	231.2	262.3	-9.5	-17.0
2015	234.9	246.3	-29.0	-36.5

As shown in Table A4-2, inclusion of the estimated demand from the BEB plant increases the LSC margin shortfall. Therefore, as explained in Section 1.6.2, it is appropriate to install a large block of capacity in 2011 to account for this and other uncertainties in the peak forecast.

The largest shortfall is anticipated to occur in 2015 with the potential loss of HC&S from the system due to the assumption of the PPA contract termination.

Over the coming year, MECO will continue to monitor demand growth, the status of the BEB project, the progress of its energy efficiency DSM programs, and continue to evaluate the CHP market.