INTEGRATED RESOURCE PLAN 2006-2025

2007 EVALUATION REPORT

Docket No. 03-0253

May 2007

Hawaiian Electric Company, Inc.

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1. INTRODUCTION

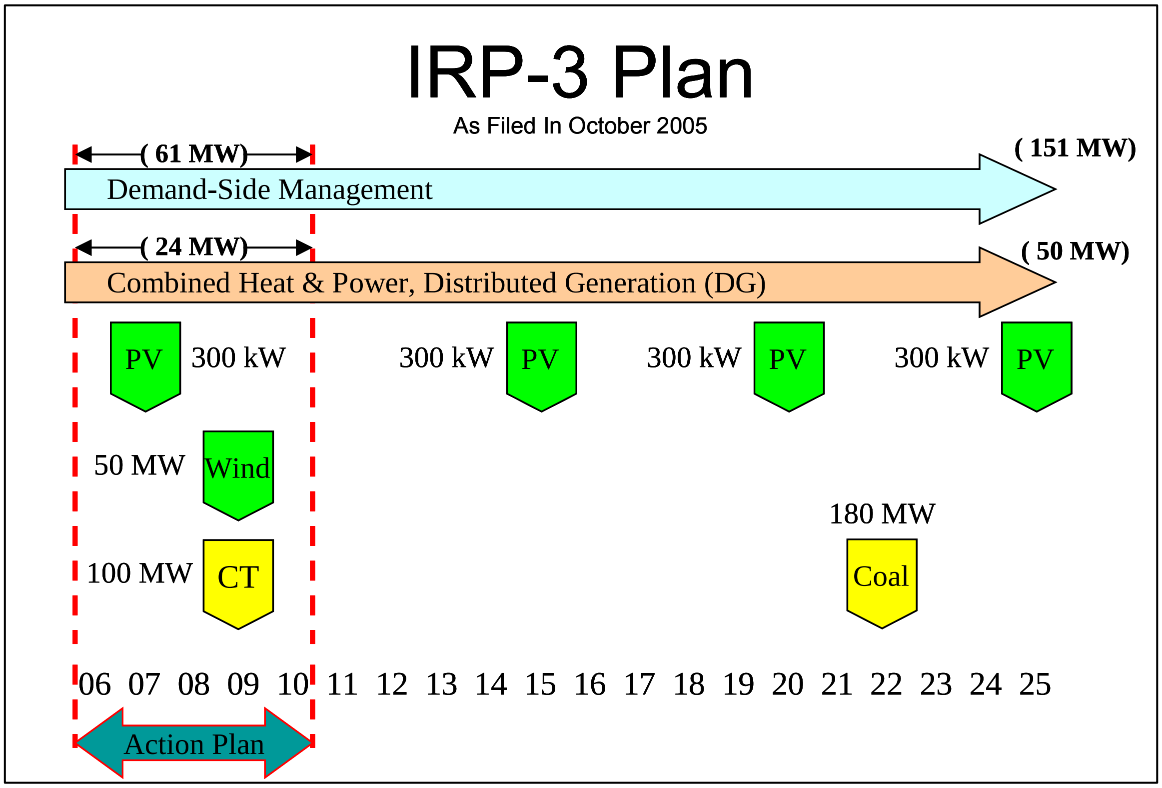
Integrated Resource Planning (IRP) is a planning process required of each energy utility in the State of Hawaii to systematically and thoroughly evaluate the choices for meeting Hawaii's future energy needs.

This evaluation provides an update to HECO's IRP-3 plan utilizing the latest information available. In addition, this evaluation report serves as a starting point for HECO's fourth IRP planning cycle (IRP-4). The evaluation report is not intended to be a complete review of the plan. HECO will conduct a major review of its IRP plan and file its fourth IRP plan (IRP-4) no later than June 30, 2008, as ordered by the PUC in Order No. 23312.

2. SUMMARY OF HECO's THIRD IRP ("IRP-3")

Hawaiian Electric Company (HECO) filed its third integrated resource plan, also referred to as the IRP-3 preferred plan, with the PUC in October 2005. The IRP-3 preferred plan (hereinafter referred to as "IRP-3 plan"), is shown in Figure 2-1:

Figure 2-1
IRP-3 Plan



The IRP-3 plan consists of a mix of demand-side management (DSM) programs, combined heat & power (CHP), photovoltaics (PV), wind generation, a peaking combustion turbine, and a coal unit within the 20-year planning period. The action plan covers the first five years of the planning period and is noted in Figure 2-1. Specific discussion of each resource in the IRP-3 is discussed in Section 15 of the IRP-3 filing.

3. CHANGES SINCE IRP-3

Since the IRP-3 report was filed in October 2005, several changes have taken place both within the State of Hawaii and beyond the State that affect the context in which HECO plans for future resource needs. This section describes the changes affecting the HECO IRP-3 plan. HECO's research, development, and demonstration efforts in developing new, and promoting existing, renewable energy technologies continue to make progress as discussed in HECO's Campbell Industrial Park Generating Station and Transmission Additions project docket (Docket No. 05-0145) See HECO T-5 (pages 10 - 11 and 17 – 18) and HECO RT-5 (pages 5 – 8).

3.1 Changes in Forecasted Demand

Future sales and peak demand for electricity in HECO's IRP-3 were based on Hawaiian Electric's February 2004 Long Term Sales and Peak forecast. HECO's most current short-term (5-year) sales and peak forecast was developed in August of 2006 (August 2006 Forecast).

As shown in Table 3.1-1, forecasted sales and peaks were generally lower in the August 2006 forecast, largely as a result of lower than expected sales in the period between the two forecasts. The development of the August 2006 Forecast and the reasons for lower sales and peak expectations are discussed more fully in the company's February 2007 Adequacy of Supply Letter to the Public Utilities Commission and in direct testimony in Docket No 06-0386 in HECO T-2.

Table 3.1-1

Hawaiian Electric Company, Inc.
FORECAST COMPARISON

GWH SALES

	Actual	February 2004	August 2006
2004	7,732.8	7,701.8	
2005	7,721.3	7,959.5	
2006	7,700.6	8,199.7	7,650.2
2007		8,381.5	7,720.8
2008		8,508.3	7,831.3
2009		8,629.0	7,921.3
2010		8,747.9	8,016.0
2011			8,069.2

PEAK DEMAND (GROSS MW)

	Actual	Feb-04	Aug-06
2004	1,327	1,338	
2005	1,273	1,385	
2006	1,315	1,425	1,319
2007		1,456	1,327
2008		1,472	1,345
2009		1,502	1,357
2010		1,524	1,370
2011			1,376

Note: Forecast peaks are not reduced for interruptible loads, but do include standby loads

3.2 Actual LSFO and Diesel Oil Actual vs. Forecast Prices

HECO purchases its low sulfur fuel oil (LSFO) and diesel, on the basis of floating prices prevailing in world markets. HECO forecasts future prices through a statistical correlation between HECO's actual prices and actual world oil prices (the price of crude oil imported into the U.S.) issued in the annual U.S. Department Of Energy, Energy Information Administration, "Annual Energy Outlook 2007 (EIA, AEO 2007). This methodology is described in Exhibit E of HECO's Act 95 "Comments Relating to the RPS Technical Paper" (filed with the Commission on October 14, 2005).

Since the IRP-3 Plan and Action Plan were filed in October 2005, there has been a significant change in EIA's forecast for world oil prices. In contrast to the steadily rising prices forecasted in the 2002 Fuel Price Forecast, the falling then rising general trajectory of world oil prices forecast by the EIA in 2007 is reflected in the 2007 Fuel Price Forecast for HECO's LSFO and diesel prices, shown in the Table 3.2-1. The sustained rise in energy prices since 2000, and the growing acceptance of the belief that higher recent price levels will not revert to those prevailing in the 1990s caused the EIA to reevaluate long-term oil price expectations in its AEO 2007. EIA attributes the near-term decline in world oil prices in the AEO 2007 reference case to the following:

"In the AEO 2007…prices…are projected to decline gradually from their 2006 average through 2015, as expanded investment in exploration and development brings new supplies to the world market. After 2015, real prices begin to rise as demand continues to grow and higher cost supplies are brought to market."[1]

A comparison of HECO's 2002 and 2007 Fuel Price Forecasts is shown in Table 3.2-1 and illustrates the magnitude of the change in forecasted prices.

Table 3.2-1

HECO Fuel Price Forecast Comparison

Year	Actual HECO LSFO Price ($/Barrel)	2002 Forecast LSFO Price ($/Barrel)	IRP-3 Advisory Group Forecast LSFO Price ($/Barrel)	2007 Forecast LSFO Price ($/Barrel)	Diff. 2007 Less 2005 LSFO Price ($/Barrel)	Actual HECO Diesel Price ($/Barrel)	2002 Forecast Diesel Price ($/Barrel)	2007 Forecast Diesel Price ($/Barrel)	Diff. 2007 Less 2005 Diesel Price ($/Barrel)	2002 Forecast Coal Price ($/MBtu)	2007 Forecast Coal Price ($/MBtu)	Diff. 2007 Less 2005 Coal Price ($/MBtu)
2002	23.71	22.54			N/A	35.61	27.31		N/A	1.67		N/A
2003	27.71	25.26			N/A	39.74	32.53		N/A	1.71		N/A
2004	35.90	26.09			N/A	52.49	34.49		N/A	1.81		N/A
2005	48.85	26.75			N/A	75.95	35.55		N/A	1.87		N/A
2006	60.03	26.77	41.04		N/A	95.22	36.73		N/A	1.91		N/A
2007		28.79	43.77	69.65	40.86		37.61	90.12	52.51	1.95	3.04	1.09
2008		29.84	45.33	68.39	38.56		39.01	88.48	49.46	1.99	3.14	1.15
2009		32.61	49.72	66.17	33.57		40.15	85.59	45.44	2.04	3.17	1.14
2010		34.10	51.99	63.83	29.73		40.08	82.55	42.47	2.08	3.20	1.12
2011		35.48	54.06	61.77	26.30		40.72	79.88	39.15	2.12	3.20	1.08
2012		36.62	55.78	60.17	23.55		41.39	77.79	36.40	2.17	3.20	1.03
2013		37.53	57.98	59.73	22.21		42.80	77.22	34.42	2.22	3.19	0.97
2014		38.32	59.60	59.98	21.66		43.95	77.54	33.59	2.26	3.21	0.94
2015		39.99	62.14	61.24	21.25		46.41	79.17	32.76	2.31	3.24	0.93
2016		41.42	64.81	62.58	21.16		49.28	80.90	31.62	2.37	3.35	0.98
2017		42.87	67.06	64.26	21.39		48.80	83.08	34.27	2.43	3.41	0.98
2018		44.37	69.90	65.98	21.60		51.74	85.30	33.56	2.48	3.43	0.95
2019		45.96	72.90	67.76	21.80		53.93	87.61	33.67	2.55	3.44	0.90
2020		47.56	75.97	69.59	22.03		55.76	89.98	34.22	2.61	3.55	0.94
2021		49.24	77.52	71.79	22.55		57.87	92.82	34.95	2.67	3.62	0.95
2022		51.00	80.32	74.12	23.12		60.06	95.83	35.77	2.73	3.66	0.93
2023			83.16	76.49	N/A			98.90	N/A		3.66	N/A
2024			86.10	78.94	N/A			102.08	N/A		3.64	N/A
2025			89.14	81.47	N/A			105.35	N/A		3.74	N/A
2026				83.68	N/A			108.21	N/A		3.83	N/A
2027				85.99	N/A			111.20	N/A		3.93	N/A
2028				88.34	N/A			114.24	N/A		4.04	N/A
2029				90.71	N/A			117.32	N/A		4.14	N/A
2030				93.19	N/A			120.53	N/A		4.26	N/A

HECO is in the process of developing a methodology to forecast future prices of biofuel, unfortunately the methodology is not yet available for this report.

3.3 Energy Efficiency Docket

On February 13, 2007, the Commission issued Decision and Order No. 23258 in the Energy Efficiency Docket (Docket No. 05-0069). In this D&O, the Commission ordered the administration of all energy efficiency DSM programs to be turned over to a non-utility, third-party administrator beginning in January 2009. The DSM programs are to be funded through a public benefits fund surcharge, to become effective at the same time. The Commission

[1] Energy Information Administration, Annual Energy Outlook 2007 with Projections to 2030, February 2007, p. 2.

further ordered that "[a] new docket shall be opened to select a Public Benefits Fund administrator and to refine details of the new market structure. Until the new market structure is effective, the HECO Companies shall continue to be responsible for overseeing their Energy Efficiency programs…"

Some uncertainties exist as to how DSM resources will be acquired in the future and how that prospective acquisition under a third party administrator will be reflected in the utility's IRP; however, for the purposes of this IRP-3 evaluation, HECO has assumed that the level of DSM acquisition through the transition and after the implementation of the non-utility market structure in 2009 will not be significantly different than what was modeled for IRP-3. Once order(s) are issued under this new docket, HECO will incorporate any changes in DSM resource assumptions resulting from the transition to the non-utility market structure in future IRP Reports.

3.4 Distributed Generation Docket

On January 27, 2006, the Commission issued Decision and Order No. 22248 in its Distributed Generation (DG) Docket No. 03-0371. In D&O 22248, the Commission indicated that its policy is to promote the development of a market structure that assures DG is available at the lowest feasible cost, that DG is economical and reliable, that DG has an opportunity to come to fruition, and to preclude DG that is not cost-effective from entering 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 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 Commission also indicated its desire to promote the development of a competitive market for customer-sited DG. Therefore, D&O 22248, as clarified by PUC Order No. 22375, 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 reasonable cost alternative to meet that need, and (3) it can be shown that 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.

The PUC also found that "The benefits of distributed generation to the grid may increase if the utility can dispatch the customer's units or coordinate their operation with the utility's own units. On the other hand, customers may wish to maintain control of the generation to assure sufficient power resources for themselves. The commission hereby requires the utility to use its best efforts to negotiate contracts that allow the utility to dispatch the customer's generation unit where dispatching the unit is economical and feasible, and coordinate their operation with the utility's own units." (D&O 22248, page 38.)

D&O 22248 also requires the Companies to establish reliability and safety criteria 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 Commission approval in July and August 2006, respectively. By Order No. 23171, dated December 28, 2006, the Commission opened a new proceeding, Docket No. 2006-0497, to investigate the Companies' proposed DG interconnection tariff modifications and standby rate tariffs.

3.5 Oahu CHP Forecast

Since the filing of the HECO IRP-3 report in 2005, HECO has significantly reduced its forecast for combined heat and power ("CHP") systems on Oahu[2]. HECO's updated short-term CHP forecast (dated July 27, 2006) used in its 2007 Adequacy of Supply ("AOS") report projects that peak reduction impacts of CHP installations will be lower than impacts projected for the 2006 AOS report.[3] 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 set forth in the PUC's decision and order in the DG Docket 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 including the increased premium for lighter fuels such as No. 2 diesel typically used in CHP applications over residual fuel oil. Further detailed explanation of these factors is provided in HECO's 2007 AOS report (see Appendix 2, pages 5-8.)

HECO's action plan for CHP in the years 2006-2010, as described in Section 15.3 of the HECO IRP-3 Report, was to pursue PUC approval of a proposed utility CHP Program and Schedule CHP tariff in Docket No. 03-0366. On December 29, 2006, HECO withdrew its 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. HECO will continue to consider CHP projects on a case-by-case basis, and if a decision is made to pursue a CHP project, then a project-specific application would be filed requesting Commission approval of such CHP project.

3.6 Substation Distributed Generation

As described in Section 15.4.1.4 of the HECO IRP-3 Report, in late 2005 HECO was proceeding with installation of nine 1.64 MW mobile, temporary DG units at utility controlled substations or other utility sites, to mitigate HECO's reserve capacity shortfall. HECO planned to evaluate further opportunities and the need for additional temporary DG installations in 2006 and beyond. HECO completed the installation of the initial nine temporary DG units in the fourth quarter of 2005, adding just under 15 MW of temporary dispatchable generating capacity at three HECO sites. Due to the continued need for additional mitigation measures determined in HECO's 2006 AOS report, in 2006 HECO proceeded to install additional temporary, 1.64 MW DG units at utility sites. Three DG units were installed at HECO's CEIP Substation in November 2006, and three DG units were placed in service at HECO's Kalaeloa Poleyard in December 2006. Three more DG units were placed in service at HECO's Ewa Nui Substation in May 2007, bringing the total temporary DG capacity to 29.5 MW.

3.7 Competitive Bidding Docket

On December 8, 2006, the Commission issued its Decision and Order No. 23121 in its investigation of competitive bidding for new generation (Docket No. 03-0372). That D&O included a Competitive Bidding Framework As Appendix A. Please refer to the Competitive Bidding Framework for detailed requirements.

2

Forecasted Cumulative CHP Installed MW (Utility and Third Party)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
IRP-3	0.0	0.0	0.0	0.8	1.6	2.4	3.2	3.2	3.2	3.2	3.2
Evaluation Report	7.7	15.9	24.8	34.2	42.9	45.9	48.6	50.8	53.0	54.7	56.4

3 For example, in the 2006 AOS report, the peak reduction impact of CHP in the year 2008 was forecasted to be 3.7 MW. In the 2007 AOS report, the peak reduction impact of CHP in the year 2008 is forecast to be 0.8 MW.

There are several requirements in the Framework for Competitive Bidding that are relevant to IRP. These include:

- Competitive bidding is the required mechanism for acquiring new generation, absent waivers or exceptions.
- IRP shall continue to be filed in accordance with the IRP Framework.
- IRP shall identify those resources or blocks of resources for which the utility proposes to hold competitive bidding and those resources for which the utility seeks waivers.
- Requests for waiver shall accompany the IRP filing for PUC approval.
- An electric utility may establish a separate procurement process (such as a "set aside" or separate Request for Proposal ("RFP") process) to acquire as-available or firm capacity from renewable generating facilities.
- IRP shall specify the proposed scope of the RFP.
- RFP processes shall be flexible, and shall not include unreasonable restrictions on sizes and type of projects considered, taking into account the appropriate sizes and types identified in the IRP process.
- In general, the utility shall develop a project proposal when the utility is addressing a need for firm capacity.
- Stakeholders must work cooperatively to adhere to appropriate timelines, which may need to be expedited, in order for competitive bidding to be effectively and efficiently integrated with a utility's IRP.

The D&O states that "Competitive bidding, unless the Commission finds it to be unsuitable, is established as the required mechanism for acquiring a future generation resource or a block of generation resources, whether or not such resource has been identified by the utility in its IRP, and the determination shall be made by the Commission in its review of the utility IRP." However, the Competitive Bidding Framework also makes provision for exemptions and allows for waivers, some of which are identified below.

<u>Overview of Exemptions from the Competitive Bidding Framework</u>

Certain capacity addition projects, including HECO's Campbell Industrial Park 110 MW (nominal) Combustion Turbine project, are explicitly exempt from the Competitive Bidding Framework. (§II.A.3.e., on page 5, of the Competitive Bidding Framework) The Competitive Bidding Framework also provides for the following additional exemptions, others:

- Offers to sell energy on an as-available basis by non-fossil fuel producers that were submitted to an electric utility before this Framework was adopted. (§II.A.3.e.(ii), on page 5, of the Competitive Bidding Framework)
- Offers to sell firm energy and/or capacity by non-fossil fuel producers that were submitted to an electric utility before this Framework was adopted, or that resulted from negotiations with respect to offers to sell energy on an as-available basis by non-fossil fuel producers that were submitted to an electric utility before this Framework was adopted; provided that negotiations with respect to such firm energy and/or capacity offers are concluded no later than December 31, 2007. (§II.A.3.e.(iii), on page 5, of the Competitive Bidding Framework)
- Power purchase agreement extensions 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. (§II.A.3.g.(iii), on page 5, of the Competitive Bidding Framework)

- Renegotiation of power purchase agreements in anticipation of their expiration, approved by the Commission.
- Customer-sited, utility-owned distributed generating units that have been approved by the Commission in accordance with the requirements of Decision and Order No. 22248, issued January 27, 2006, as clarified by Order No. 22375, issued April 6, 2006 in Docket No. 03-0371. (§II.A.3.f.(iii), on page 5, of the Competitive Bidding Framework)
- Renewable energy or new technology generation projects under 1 MW installed for "proof-of-concept" or demonstration purposes. (§II.A.3.f.(iv), on page 5, of the Competitive Bidding Framework)

Please see §II.A.3.e. through §II.A.3.g., on pages 5 and 6, of the Competitive Bidding Framework for a complete list of prospective exemptions.

Overview of Waivers from the Competitive Bidding Framework

The Commission acknowledges that competitive bidding may not always be the appropriate means to acquire new generating capacity. Under certain circumstances, the utility may submit to the Commission for approval a request for a waiver from the Competitive Bidding Framework.

Following are examples of circumstances where a waiver from competitive bidding may be considered:

- When competitive bidding will unduly hinder the ability to add needed generation in a timely fashion. (§II.A.3.b.(i), page 4 of the Competitive Bidding Framework)[4]
- The acquisition of near-term power supplies to meet short-term needs. (§II.A.3.c.(ii), page 4 of the Competitive Bidding Framework)
- The acquisition of power from a non-fossil fuel facility (such as a waste-to-energy facility) that is being installed to meet a governmental objective. (§II.A.3.c.(iii), also page 4 of the Competitive Bidding Framework)

Please see §II.A.3.b. through §II.A.3.d. on page 4 of the Competitive Bidding Framework for a more complete description of circumstances where a waiver from competitive bidding may be considered.

In essence, it is anticipated that implementation of the Competitive Bidding Framework will result in fundamental changes to the content of a major IRP filing (such as for IRP-4). For example, rather than identifying specific types, sizes and timing of supply-side resources in the long-term resource plan as was done in IRP-1, IRP-2 and IRP-3, the long-term plan will likely show the timing of the need for blocks of capacity (including the size, in MW, of the blocks but not necessarily specifying the type of resource) and the attributes associated with these resources or blocks of resources. Since the specific type and size of resource to be added to the system will likely be determined through a competitive bidding

[4] The steps necessary to conduct a competitive bidding process for firm capacity are generally anticipated to take approximately two to three years to conduct, which does not include the time required for securing all necessary regulatory permits and approvals, land rights, and for the winning bidder to complete actual project engineering and design, equipment procurement, construction and commercial testing.

process, the rigorous optimization of supply-side resources typically done in a major IRP process need not be performed. The analysis of competing supply-side resources will instead be performed as part of the evaluation of bids received in response to RFP for new generation.

3.8 Adequacy of Supply and Reserve Margin Shortfall

HECO filed its 2007 Adequacy of Supply ("AOS") report with the Commission on February 27, 2007. HECO determined through its generating system reliability analysis performed for the 2007 AOS report that the reserve capacity shortfall[5] that currently exists will be significantly reduced when a 110 MW (nominal) simple cycle combustion turbine is installed in mid-2009 as targeted, but a reserve capacity shortfall will still exist. Several scenarios were evaluated, and the results are summarized in Table 3.8-1. [6]

Table 3.8-1
Reserve Capacity Shortfall for Reference
and Single-Sensitivity Scenarios, MW
Nominal 110 MW 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

The reserve capacity shortfall values represent the number of megawatts ("MW") needed to increase generating system reliability to the guideline value of 4.5 years per day[7] that is contained in HECO's capacity planning criteria. For example, in the reference scenario, in 2009, an additional 40 MW of firm capacity are needed to increase generating system reliability to 4.5 years per day. (HECO uses negative MW values to indicate a shortfall of capacity. Positive numbers would indicate a surplus of capacity.) Substantial information on this analysis is provided within the 2007 AOS report.

The Reference Scenario uses a reference load forecast; the Higher Load Scenario uses a load forecast that is approximately 60 MW higher than the reference load forecast;

[5] Reserve capacity shortfall is defined as the amount of additional generation (or equivalent load reduction) in MWs required to restore generation system reliability to HECO's minimum reliability guideline of 4.5 years/day loss of load probability pursuant to HECO's capacity planning criteria.

6 The reserve capacity shortfalls associated with these scenarios assume that the 110 MW 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.

[7] HECO has a reliability guideline threshold of 4.5 years per day. This means that there should be 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.

the Two-Month 90 MW Outage Scenario uses the reference load forecast but assumes that a 90 MW generating unit becomes unavailable for a two-month period due to an unexpected problem (over and above the reference Equivalent Forced Outage Rates)[8]; and the 5-Yr Avg EFOR Scenario uses Equivalent Forced Outage Rates ("EFOR") that are generally lower (based on the 2002-2006 5-year average for each generating unit) than in the Reference Scenario.[9]

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 3.8-2, 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 3.8-2:
Reserve Capacity Shortfall for
Reference and Compound Scenarios, MW
Nominal 110MW CT installed in Mid-2009

	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 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 load growth, less load-reducing impacts from energy efficiency DSM or load management, or a combination of these factors).

8 This sensitivity scenario assumed an 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.

9 The use of 5-year average EFORs for HECO generating units results 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.

Figure 3.8-1 illustrates the August 2006 peak forecast used in the 2007 AOS report, the Higher Load Scenario used in the 2007 AOS report, the May 2005 peak forecast used in the 2006 AOS report, and recorded system peaks. The Higher Load Scenario with peaks above the August 2006 forecast (but lower than the peaks forecast in May 2005) was analyzed in recognition of 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.

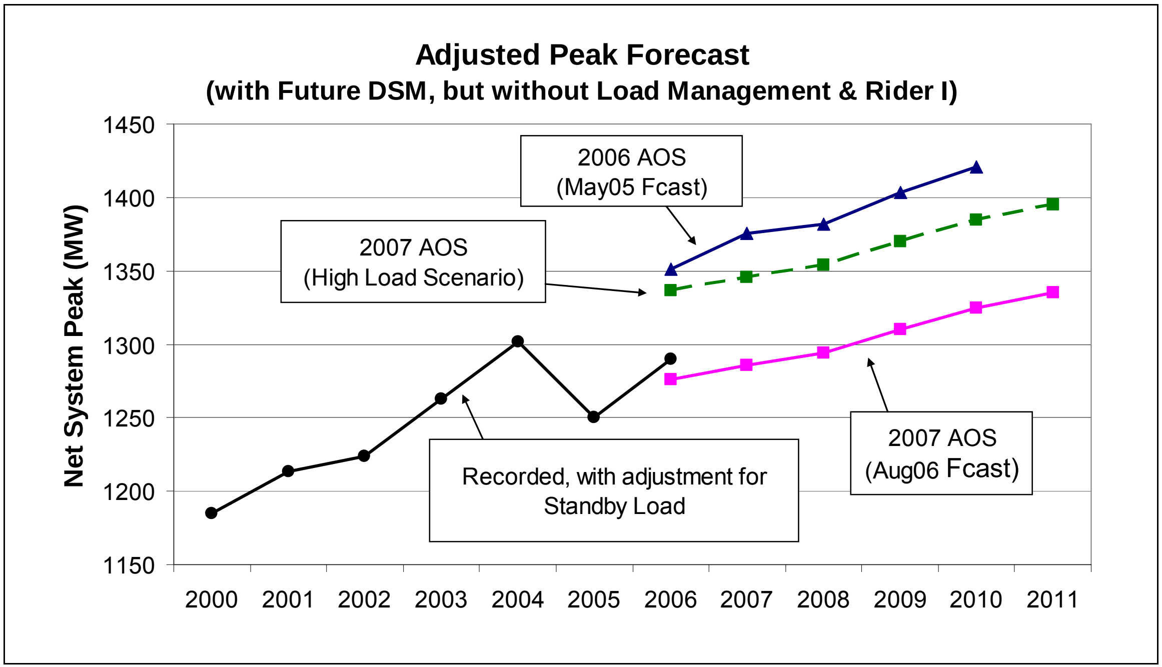


Figure 3.8-1: Recorded Peaks and Future Year Projections

HECO has taken a number of steps to mitigate the effects of reserve capacity shortfalls, such as installing temporary distributed generators 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. Until sufficient generating capacity can be added to the system, HECO will experience a higher risk of generation-related customer outages and experience reserve capacity shortfalls that are more frequent and longer in duration. HECO will operate at lower-than-established reliability levels and take steps to mitigate the reserve capacity shortfall situation until sufficient generating capacity is installed.

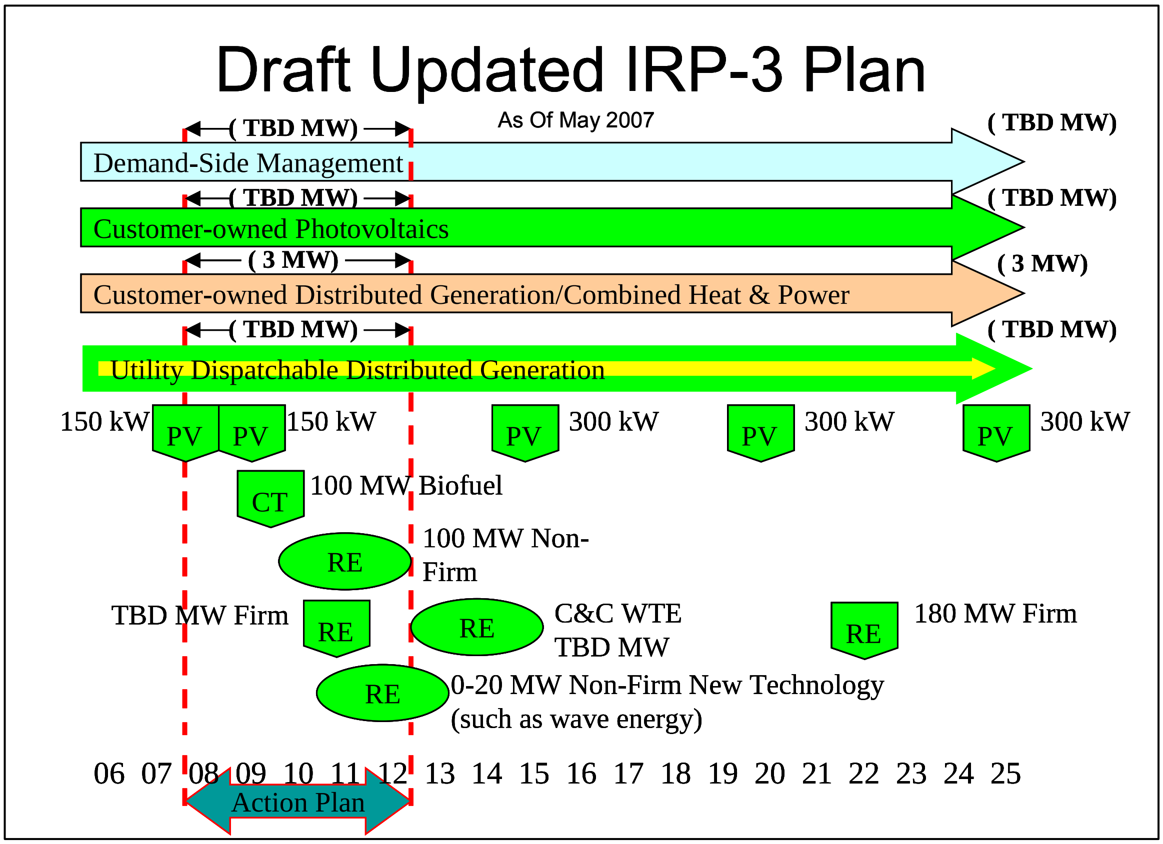
HECO has made progress toward the installation of the combustion turbine at Campbell Industrial Park and is optimistic that the nominal 110 MW increment of firm capacity can be added to the system by mid-2009. However, after the planned mid-2009 addition of the Campbell Industrial Park generating unit, HECO anticipates the potential for continued reserve capacity shortfalls to range between 20 MW and 110 MW in the 2009 to 2012 period, recognizing the uncertainty underlying key forecasts. HECO's plans for additional firm capacity to meet the reserve capacity shortfall that is anticipated to continue even with the planned mid-2009 addition of the Campbell Industrial Park generating unit are discussed in Section 4.2.6.

4. UPDATED IRP-3 PLAN AND ACTION PLAN

4.1 Updated IRP-3 Plan

Based on changes since the IRP-3 plan was filed in October 2005, HECO has updated its IRP-3 plan. The Updated IRP-3 plan is shown in Figure 4.1-1 and serves as the base plan for future planning activities. This includes serving as the starting point for HECO's IRP-4. This IRP plan identifies renewable energy for all future supply-side resource needs. Each resource is described below in the order in which it appears in Figure 4.1-1, and a more complete description of each resource can be found in the updated action plan in Section 4.2.

Figure 4.1-1



Demand-Side Management: The Demand-Side Management program is comprised of the following resource portfolio:

Existing DSM energy efficiency programs:

- Commercial and Industrial Energy Efficiency Program (CIEE)
- Commercial and Industrial New Construction Program (CINC)
- Commercial and Industrial Customized Rebate Program (CICR)
- Residential Efficient Water Heating Program (REWH)
- Residential New Construction Program (RNC)

Load Management Programs:

- Residential Direct Load Control Program (RDLC)
- Commercial and Industrial Direct Load Control Program (CIDLC)

<u>New DSM energy efficiency programs</u>:

- Energy Solutions for the Home Program (ESH)
- Residential Low Income Program (RLI)
- Residential Customer Energy Awareness Program (RCEA)

Customer-Owned Photovoltaics: This will be an estimate of customer-sited photovoltaic systems over the planning period. The estimate is likely to increase, in part due to federal tax incentives. Included in this resource type are larger PV systems installed by commercial customers as well as smaller PV system installed on smaller commercial facilities or residences that qualify under the net energy metering (NEM) program.

Customer-Owned Distributed Generation / Combined Heat & Power: Projects not dispatchable by the utility.

Utility Dispatchable Distributed Generation: Utility-owned and customer-owned distributed generation, dispatchable by the utility.

Utility Photovoltaics (PV): Larger 150 - 300 kW photovoltaic systems through utility ownership or power purchase agreement.

Biofuel Combustion Turbine (100 MW Nominal): 110 MW simple-cycle combustion turbine-generator in Campbell Industrial Park utilizing biofuel.

Non-Firm Renewable (100 MW): 100 MW of non-firm renewable resources.

Firm Renewable (100 MW): Additional 100 MW of firm capacity renewable energy.

C&C Waste-to-Energy (TBD MW): The City & County of Honolulu issued a Request For Competitive Sealed Proposals ("CSP No. 037") in January 2007 for the addition of waste-to-energy processing capacity and/or the refurbishment of the existing H-Power waste-to-energy facility at Campbell Industrial Park.

Firm Renewable (180 MW): 180 MW of firm capacity renewable energy in 2022

Non-Firm New Technology (0-20 MW): Up to 20 MW of non-firm energy from emerging technologies for installation later in the Action Plan period.

4.2 Updated Action Plan

This section of the report contains an updated Action Plan for the updated IRP-3 plan shown in Figure 4.1-1. The updated Action Plan reflects HECO's current activities up through 2012 to implement the updated IRP-3 plan.

4.2.1 Demand-Side Management

HECO will continue to operate a broad and aggressive portfolio of DSM programs through December 2008 and will assist in the transition of these programs to the third party administrator thereafter. The objectives of the DSM portfolio continue to include:

- Energy and demand reductions
- Consistency with HECO's IRP plan and with the State's Renewable Portfolio Standards law
- Participation by all classes of customers
- Cost-effectiveness
- Market transformation

HECO's DSM resource portfolio includes HECO's eight energy efficiency programs approved in D&O 23258, issued on February 13, 2007, and two load management programs, as previously outlined:

The load reduction and energy savings impact resulting from HECO's energy efficiency and load management DSM programs for 2007-2008 and from the continuation of these programs under the third party administrator for 2009-2011 are approximately 91 MW and 289 GWh, as shown in Table 4.2.1-1 and Table 4.2.1-2.

Table 4.2.1-1

Forecasted DSM Impacts 2007-2011 (Gross Participation at Gross System Level Demand kW)

	CIEE	CINC	CICR	C&I Total	REWH	RNC	E$H	RLI	Res Total	RDLC	CIDLC	TOTAL
2007	3,439	1,432	1,649	6,520	864	889	1,099	0	2,852	7,215	2,983	19,570
2008	3,439	1,432	1,649	6,520	864	1,123	2,155	591	4,733	3,144	8,331	22,728
2009	3,439	1,432	1,649	6,520	864	1,123	2,155	591	2,578	854	7,768	19,875
2010	3,439	1,432	1,649	6,520	864	1,123	1,744	591	2,578	148	6,951	17,941
2011	3,439	1,432	1,649	6,520	864	1,123	-728	591	2,578	0	2,280	10,650
Total	17,195	7,160	8,245	32,600	4,320	5,381	6,425	2,364	15,319	11,361	10,500	90,764

Table 4.2.1-2

Forecasted DSM Impacts 2007-2011 (Gross Participation at Gross System Level Energy MWh)

	CIEE	CINC	CICR	C&I Total	REWH	RNC	E$H	RLI	Res Total	TOTAL
2007	23,379	9,770	12,626	45,775	3,767	3,023	5,887	0	12,677	58,452
2008	23,379	9,770	12,626	45,775	3,767	2,823	7,142	2,633	16,365	62,140
2009	23,379	9,770	12,626	45,775	3,767	2,823	7,142	2,633	16,365	62,140
2010	23,379	9,770	12,626	45,775	3,767	2,823	4,934	2,633	14,157	59,932
2011	23,379	9,770	12,626	45,775	3,767	2,823	-8,310	2,633	913	46,688
Total	116,895	48,850	63,130	228,875	18,835	14,315	16,795	10,532	60,477	289,352

The forecasted load reduction resulting from HECO's energy efficiency and load management DSM programs for 2005-2006 in HECO's IRP 3 plan was approximately 42 MW, as shown in Table 4.2.1-3.

Table 4.2.1-3

Forecasted DSM Impacts 2005-2006 (Gross Participation at Gross System Level Demand kW)

	CIEE	CINC	CICR	C&I Total	REWH	RNC	ESH	RLI	Res Total	RDLC*	CIDLC*	TOTAL
2005	2,700	810	2,200	5,710	1,260	1,180	2,700	680	5,820	4,530	5,250	21,310
2006	2,700	810	2,200	5,710	1,260	1,180	2,700	680	5,820	4,480	5,250	21,260
Total	5,400	1,620	4,400	11,420	2,520	2,360	5,400	1,360	11,640	9,010	10,500	42,570

* An error was made in the table presented in Chapter 6 on page 6-22, of the IRP 3 Report filed on October 28, 2005. The impact of the load management programs was presented as cumulative as apposed to incremental. That error has been corrected in this table. The actually acquired load reduction was approximately 31 MW, as shown in Table 4.2.1-4.

Table 4.2.1-4

Acquired DSM Impacts 2005-2006 (Gross Participation at Gross System Level Demand kW)

	CIEE	CINC	CICR	C&I Total	REWH	RNC	ESH	RLI	Res. Total	RDLC	CIDLC	TOTAL
2005	1,650	1,331	2,396	5,377	801	873	0	0	1,674	4,025	2,145	13,221
2006	1,821	2,258	2,078	6,157	1,077	1,135	313	0	2,525	6,445	2,695	17,822
Total	3,471	3,589	4,474	11,534	1,878	2,008	313	0	4,199	10,470	4,840	31,043

While HECO's C&I energy efficiency programs performed as expected, and the residential load management program significantly over-performed to a degree, the residential energy efficiency and C&I load management program under-performed relative to forecast. The under-performance of the residential energy efficiency programs was primarily the result of an optimistic assumption regarding the timing of the implementation of the Energy Solutions for the Home (ESH) and Residential Low Income (RLI) Programs. Consequently, no demand reduction was achieved by the ESH and RLI Programs in 2005, and only a small reduction was achieved in 2006 with the approval of HECO's Interim DSM Proposal[10].

The under-performance of the CIDLC Program in its first two years of implementation is the result of some programmatic difficulties and an under-appreciation of the challenge customers face when subjected to immediate service interruption from activation of the under-frequency relay. 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 is expected to lead to greater load reductions under the CIDLC program, but this situation will not be corrected before 2009.

Energy reductions resulting from HECO's energy efficiency DSM programs for 2005-2006 forecasted in HECO's IRP 3 plan are approximately 130 GWh, as shown in Table 4.2.1-5.

Table 4.2.1-5

Forecasted DSM Impacts 2005-2006 (Gross Participation at Gross System Level Energy MWh)

	CIEE	CINC	CICR	C&I Total	REWH	RNC	E$H	RLI	Res Total	TOTAL
2005	18,960	5,680	15,800	40,440	4,830	2,530	14,950	2,520	24,830	65,270
2006	18,960	5,680	15,800	40,440	4,830	2,530	14,950	2,520	24,830	65,270
Total	37,920	11,360	31,600	80,880	9,660	5,060	29,900	5,040	49,660	130,540

The actually acquired load reduction impacts are approximately 104 GWh, as shown in Table 4.2.1-6

[10] On April 26, 2006 the Commission in Order No. 22420 approved HECO's Interim DSM Proposal, increasing rebate levels for some DSM measures and approving an interim residential CFL program similar to what was proposed in the ESH Program.

Table 4.2.1-6

Acquired DSM Impacts 2005-2006 (Gross Participation at Gross System Level Energy MWh)

	CIEE	CINC	CICR	C&I Total	REWH	RNC	E$H	RLI	Res Total	TOTAL
2005	15,298	10,539	18,298	44,135	3,537	2,278	0	0	5,816	49,951
2006	15,438	14,273	14,529	44,240	4,754	3,328	1,922	0	10,005	54,245
Total	30,736	24,812	32,827	88,375	8,292	5,607	1,922	0	15,820	104,195

While HECO's C&I energy efficiency programs performed as expected, the residential energy efficiency programs under-performed relative to the forecast. This is the result of timing assumptions as described above.

4.2.2 Utility Dispatchable Distributed Generation

HECO has successfully installed temporary DG systems to help mitigate its reserve capacity shortfall. HECO will build on this experience and evaluate the role of distributed generation in the course of HECO IRP-4. Various potential applications of DG, as set forth in the DG Docket D&O 22248, include deferring the need for distribution system infrastructure, reducing T&D line losses and providing voltage support, allowing generating capacity to be added incrementally, and increasing grid reliability. The degree to which these benefits are realized, however, depends on many factors including permit requirements, DG size, technology type, location, operational characteristics, fuel storage and logistics, cost, and interconnection.

Ultimately, the IRP-4 DG assessment will attempt to identify long term DG resources that optimally benefit HECO's system and ratepayers, with focus on utility-dispatchable DG. Utility-dispatchable DG includes both HECO-owned DG units and DG units owned by customers with whom HECO has contractual arrangements allowing utility dispatch.

As input to IRP-4, HECO will incorporate its ongoing evaluation of dispatchable standby generation (DSG), wherein the utility, by contractual arrangement subject to PUC approval, is allowed to dispatch customer-owned standby generators operating in parallel with the HECO grid, in order to provide potential benefits to the HECO system. 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.[11] Such emergency power equipment would generally be installed and owned by the customer. HECO could contribute funding for certain equipment items required to enable utility dispatch, and pay the customer for the utility dispatch rights. HECO's DSG concept is based in large part on the active DSG program by Portland General Electric Company ("PGE"), the largest regulated electric utility serving the state of Oregon. Since the inception of its DSG program in 2000, PGE has contracted for 43 MWs[12] of DSG capacity from various commercial and industrial customers.

HECO has been working with the State Department of Transportation Airports Division ("DOT Airports") since December 2005 to determine the feasibility of incorporating DSG into an emergency generating facility to be built by DOT Airports at the Honolulu

[11] The extent to which DG or DSG should be included in generation planning for an isolated island grid must be evaluated in more detail. Factors to consider include the potential run-hour constraints of air permits for these units.

[12] As of April 24, 2007

International Airport. HECO continues to work closely with DOT Airports and anticipates negotiation of a DSG agreement in 2007, which would subsequently be filed for PUC approval. Based on current plans, the DOT Airports emergency generating facility could provide approximately 8 MW of DSG capacity.

HECO has also been in preliminary discussion with a number of other potential DSG customers, all of whom have plans underway to install new standby generators at their facilities in the near future. HECO has not yet determined the suitability of DSG for these customers.

HECO does not intend to provide DSG as a broad programmatic offering to customers. Instead, HECO anticipates development of a limited number of DSG projects on a one-off basis, in order to selectively focus on the projects that appear most cost-effective and technically feasible. In approaching DSG on a more controlled and limited basis, HECO anticipates that it will be better able to optimize the benefits of DSG to ratepayers, consistent with the goals set forth by the PUC in D&O 22248.

4.2.3 Utility Photovoltaics

HECO's IRP-3 Supply-Side Action Plan identified multiple blocks of utility-owned photovoltaic ("PV") systems, to be installed on HECO sites. A total of 1.2 MW of such utility PV systems was planned. In 2006, HECO conducted an extensive evaluation of its Ward Avenue complex to determine the feasibility of installing utility-owned PV at that site. It was determined that the Archer Substation rooftop presented the most viable and cost-effective site for PV. HECO also determined that it was most cost-effective to seek non-utility development of the PV system due to the non-availability of federal renewable energy investment tax credits to the regulated utility.

Based on these determinations, on March 22, 2007, HECO issued a request for proposals to non-utility PV developers, seeking development of an approximate 155 kW (dc) of PV on Archer Substation by the end of 2007. HECO intends to purchase the energy produced by the PV system, subject to PUC approval. Bids were received at the end of April and are currently under review.

HECO will evaluate its experience in developing the Ward Avenue PV and will pursue additional increments of PV in the near future. HECO may also broaden its efforts in the future to include other solar energy generating technologies such as solar thermal.

4.2.4 Biofuel Combustion Turbine (100 MW Nominal)

HECO continues to make progress toward installation of a 110 MW biofuel fired simple-cycle combustion turbine-generator in Campbell Industrial Park. On May 23, 2007, the Commission issued Decision and Order No. 23457 in Docket No. 05-0145 approving HECO's proposals to construct a new biofuel fired 110 MW combustion turbine at its facility in Campbell Industrial Park and a related new 138 kV transmission line, approximately two miles long, between HECO's AES Substation and CEIP Substation. (HECO is still awaiting the outcome of the accompanying "Community Benefits" docket.) Additionally, on May 23, 2007, the Hawaii Department of Health issued the final air permit, which is anticipated to become effective in late June 2007.

Following issuance of an effective air permit, HECO will release Siemens to complete the design and manufacture of the combustion turbine-generator package. HECO will also pursue a competitive procurement process for other major equipment items such as transformers and the water treatment system. Final generating station design will be completed in parallel with equipment procurement.

HECO is currently in the process of competitively bidding a contract to supply biofuel (biodiesel or ethanol) for the new generating unit. Following evaluation of the biofuel bids, HECO will negotiate a contract with the winning bidder and submit this contract to the Commission for approval.

After receiving the appropriate construction permits, HECO will begin site work followed by equipment and building erection. Startup and acceptance testing of the new generating equipment will be completed using either naphtha or 0.05% sulfur diesel. Upon satisfactory test results, the plant will be placed into commercial operation. Next, the unit will undergo emissions testing using the selected biofuel to gather data for an air permit modification request. Once the air permit is modified HECO will switch from naphtha or 0.05% sulfur diesel to the selected biofuel. The target service date for this 110 MW renewable firm capacity generating unit remains mid-year 2009.

4.2.5 Non-Firm Renewable (100 MW)

HECO is in various stages of negotiation with several IPP developers for purchase of renewable energy. It is HECO's intent to continue discussions with these "grandfathered" developers[13] to seriously examine the viability of these projects and to establish a reasonable schedule for bringing these discussions to conclusion. In parallel with this effort, HECO is targeting issuance of a Solicitation of Interest ("SOI") on or about September, 2007, announcing HECO's intent to proceed with an RFP for approximately 100 MW of non-firm renewable energy. The anticipated RFP to follow is targeted for issuance on or about year-end 2007[14], with a desired service date for the resource or resources totaling up to 100 MW in the 2010 to 2012 timeframe. HECO plans to submit to the Commission by separate filing a request for approval to proceed with the competitive procurement process outlined here.

The objectives to be accomplished by issuing the SOI include:

- Support the timely acquisition of a significant increment of the best as-available renewable energy resources the market can produce on Oahu;
- Stimulation and expansion of the prospective bidder market by providing advance notice of the RFP issuance;
- Adequate time for prospective bidders to assemble well-developed bids; and
- An opportunity for bidders to comment on the anticipated preliminary RFP scope and desired resource characteristics

The SOI is anticipated to include at least the following information:

- Preliminary scope of the planned RFP;
- Anticipated characteristics of the resources desired;

[13] HECO is continuing discussions with these developers pursuant to exemptions from the Competitive Bidding Framework for certain offers to sell energy or capacity by non-fossil fuel producers submitted before adoption of the Competitive Bidding Framework.

[14] Issuance of an RFP by year-end 2007 that is consistent with all of the requirements of the Competitive Bidding Framework, including a Commission approved code of conduct applicable to bids by the utility or its affiliate, is ambitious. To simplify and expedite the proposed RFP process, it is anticipated that no utility or affiliate bid will be submitted for this non-firm renewable resource RFP.

- Information on transmission constraints associated with likely areas of resource interconnection; and
- Anticipated competitive solicitation process summary, milestones and schedule.

The SOI will also inform prospective bidders that HECO is in direct negotiation with several IPP developers, and that there is a potential that the planned RFP may not be issued if the outcome of ongoing discussions with those developers is likely to result in agreements to purchase significant amounts non-firm renewable energy. Thus the actual amount of additional as-available renewable energy that could result from the anticipated RFP may depend on the commitments derived from the current ongoing negotiations with IPP developers and other operational or economic constraints. HECO will be requesting a waiver from competitive bidding framework requirement of an approved IRP to proceed with issuing this SOI and subsequent RFP for this block of renewable energy. HECO's request for the waiver will be filed with the Commission separately.

In scoping the desired resource attributes and performance standards sought in the planned RFP for a 100 MW block non-firm renewable energy, HECO recognizes that the acquisition of a second block of renewable energy is likely to be a desired objective of the HECO IRP-4 planning process presently underway. To not foreclose the ability of the HECO system to take on more renewable energy later, relatively strict operating performance standards will be required from those non-firm renewable energy resources presently being sought both through the ongoing IPP negotiations and the planned RFP. Studies to determine the required attributes of the renewable energy resources and necessary standards of performance are in progress. These analyses are also critical to the HECO IRP-4 process in evaluating the potential to integrate and properly scope a second block of renewable energy resources for the electric grid on Oahu.

While HECO has gained experience with integrating non-firm renewable energy resources, in particular wind resources, at HELCO and MECO, HECO has learned that integrating wind generation onto a small isolated island grid presents many challenges in operating the system and maintaining system stability. Some of the challenges include:

- System stability – ensuring the system will not experience blackouts following line faults and generation loss with high wind penetration
- Optimizing unit scheduling - requires accurate hour-ahead and day-ahead forecast, not presently available from wind farms and other intermittent resources.
- Frequency Control – variations in the output of intermittent resources can cause variations in system frequency. If frequency deviations become too large, the system is less stable and can lead to short customer outages (under frequency load shed) or extensive outages (if the deviation leads to system failure)
- System Management – standard Energy Management Systems (EMS) are not configured to work with high wind penetration. They must be "tuned" to account for the variable output of wind farms and direct the rest of the system to respond to those fluctuations. If the EMS is not tuned property it could worsen the fluctuations.
- Cost and emissions related to provide additional regulating reserve – providing the regulating reserve to account for the irregular nature of intermittent resources can require regulating units to operate at reduced fuel efficiency which increases both costs and emissions for those units. Constant regulation to counter the intermittent variations also increases the wear and tear on the regulating units.

HECO is currently researching how other utilities with relatively small systems deal with high wind penetration. Addressing some of the challenges that as-available resources present will allow HECO to maximize the amount of as-available renewable resources that can be integrated into its system and still maintain reliable operation.

In addition, HECO, HELCO and MECO are collaborating with the Hawaii Natural Energy Institute and GE Energy on a Department of Energy funded project called the Hawaii Energy Roadmap. The primary objective of the project is to develop and execute an unbiased energy scenario analysis that addresses the future energy interests of the Big Island and initiates further study of a technology-specific project that serves as another step on a path toward meeting the island's energy objectives. In the first phase of this project, GE will evaluate system and cost impacts of existing wind farms on HELCO's system and evaluate potential mitigating technologies. GE will then estimate the cost impacts of incremental increases in penetration of as-available resources such as wind. In phase 2 of the project GE will analyze potential future energy scenarios using the results developed in phase 1. This is an ambitious and technically challenging study that in some cases will require assumptions to fill in gaps where data or information is currently not available. Therefore, care will need to be taken in evaluating the results. It is hoped that these research and study efforts will help to better understand and quantify the effects of integrating intermittent resources onto the relatively small electrical grids in Hawaii and will help to chart a clearer course to achieve maximum penetration of renewable resources into the HECO, MECO, and HELCO systems without sacrificing reliability or power quality.

4.2.6 Firm Renewable (TBD MW)

As explained in Section 2.9 (Adequacy of Supply), HECO expects that some level of reserve capacity shortfall will persist even after the 110 MW (nominal) simple cycle biofueled combustion turbine is installed in 2009. Given uncertainties in the sales and peak forecast, the amount of peak reduction acquired through energy efficiency DSM programs, the amount of peak reduction acquired through load management programs, the future generating unit availability for HECO and IPP units, and the amount of other firm capacity renewable energy acquired in the near term, there is uncertainty in the amount of firm generating capacity that will need to be acquired after 2009 to overcome the continuing reserve capacity shortfall. HECO anticipates the potential for continued reserve capacity shortfalls could range between 20 MW to 110 MW in the 2009 to 2012 period.

For this increment of firm capacity, HECO seeks the following firm capacity resource attributes in the 2010 timeframe to support stable and reliable electrical grid operation:

- Dispatchability, where the utility can control from moment to moment the amount of electrical power delivered to the grid.
- Ability to help control system frequency.
- Ability to help control system or local voltage.
- Ability to follow load.
- Ability to reasonably ride through underfrequency and undervoltage conditions.
- Ability to provide spinning reserve and quick load pickup.
- Ability to turn off at least once each day (i.e., have cycling capability).
- Ability to coordinate planned maintenance outages (due to seasonal load, conflicts with HECO or IPP generators, or synchronization w/transmission line maintenance).
- Ability to respond to coordination efforts from HECO dispatch center.

- A strong preference for renewable energy.

HECO is moving quickly to implement competitive bidding for new generation and at the same time is concerned with the extended lead time to acquire large firm capacity through an RFP process for the near-term timeframe of 2010. HECO is concurrently working on a number of pre-competitive bidding activities such as establishing a qualified independent observer, preparing a code of conduct and procedures manual, submitting to the Commission the Company's proposed Rule 19 establishing tariff provisions for Interconnection and Transmission Upgrades, and establishing an organizational structure.

In parallel with these activities, HECO is considering the use of competitive bidding to acquire the capacity anticipated to be needed after the simple cycle biofueled combustion turbine is installed in 2009. However, the steps necessary to conduct a competitive bidding process for firm capacity is generally anticipated to take approximately two to three years to conduct, which does not include the time required for securing all necessary regulatory permits and approvals, land rights, and for the winning bidder to complete actual project engineering and design, equipment procurement, construction and commercial testing. Thus, iIt is uncertain as to whether firm capacity resources acquired through a competitive bidding process can be in service within the timeframe that firm capacity is needed pursuant to the 2007 AOS report. This extended lead time to acquire large firm capacity through an RFP poses a dilemma for HECO. Thus to help meet its obligation to provide reliable power and consistent with Competitive Bidding Framework, HECO continues to conduct parallel or contingency resource planing to meet its firm capacity needs in the 2010 timeframe.

4.2.7 C&C Waste-to-Energy (TBD MW)

HECO currently purchases 46 MW of firm capacity and renewable energy from the existing H-Power waste-to-energy facility at Campbell Industrial Park. On January 16, 2007, the City & County of Honolulu issued a Request for Competitive Sealed Proposals ("CSP No. 037") for the addition of waste-to-energy processing capability and/or the refurbishment of the existing H-Power facility. Copies of CSP No. 037 may be obtained from the City.

The primary purpose of the City's waste-to-energy facility is to serve the societal need to reduce the volume of refuse that is placed into landfills. Electrical generation is a by-product of the operation of the facilities, therefore, CSP No. 037 specifies the amount of refuse that will need to be processed by the new and/or refurbished facilities, but it does not specify the amount of electrical energy and capacity to be produced by the facilities. The amount of energy and capacity that may be delivered to the HECO grid will be determined from the individual proposals.

Given the uncertainty at this early stage of the City's competitive procurement process under CSP No. 037, no specific amount of additional firm capacity is assigned to future waste-to-energy facilities in this IRP-3 Evaluation Report. Similarly, while CSP No. 037 specifies a target service date, the actual schedule of the successful bidder will determine when additional generating capacity and renewable energy will be added to the HECO system. Thus, while the integration of additional renewable waste-to-energy facilities is anticipated on the HECO grid, the resource technology to be employed, the amount of potential firm capacity and renewable energy to be added, and the service date of the resource is yet to be determined and will be further considered in the IRP-4 process.

A waste-to-energy resource could qualify for a waiver from competitive bidding, as it is the illustrative example expressly recognized by the Commission in its Framework for Competitive Bidding at Section II.A.3.c.(iii) of "a non-fossil fuel facility that is being installed to meet a governmental objective." As the resource is inherently dependent on the City's assessment and initiative for a waste-to-energy facility to meet Oahu's waste disposal needs, HECO expects that a waiver from the competitive bidding process is most appropriate for the acquisition of power from such a resource. HECO expects to file its request for a waiver from competitive bidding at such time as the City makes firm plans.

4.2.8 Firm Renewable (180 MW)

Within HECO's IRP-3 preferred plan filed in October 2005 was a 180 MW coal-fired unit in 2022. (See Figure 1.17-1, on page 1-24, of HECO's IRP-3 report, filed with the Commission on October 28, 2005 in Docket No. 03-0253). Considering the heightened sensitivity to releases of CO_2 and its impact on global warming, as well as the higher CO_2 emission rates from coal-fired power plants, the appropriate type of firm capacity generating unit needed in the 2022 timeframe will be re-evaluated in IRP-4.[15] This IRP-3 Evaluation Report considers the strong preference for renewable energy and shows that this need for firm generating capacity will be met by a renewable firm capacity resource or resources. HECO anticipates securing this firm capacity resource need through a competitive solicitation process pursuant to the Competitive Bidding Framework; however the need for this firm capacity generating unit will be affected by, among other things, the firm capacity resources mentioned in Section 4.2.6 and Section 4.2.7 and existing IPP contracts mentioned in Section 4.2.11. Thus this firm capacity resource acquisition will continue to be examined in future IRP analyses.

4.2.9 Non-Firm New Technology (0-20 MW)

HECO is considering the integration of emerging renewable energy technologies, such as wave energy, into the grid. HECO has created a "set-aside" for up to 20 MW of non-firm energy from emerging renewable technologies, envisioned for service in the 2011 to 2013 timeframe. HECO is developing a procurement strategy for these renewable energy resources, and is discussing a solicitation of interest to stimulate the market, assess the commercial viability of emerging renewable technologies, and identify potential sites to locate such resources. A procurement strategy will be the subject of analysis in HECO IRP-4.

4.2.10 Generating System Reliability Analysis

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 perform an analysis of its reliability guideline in its IRP-4 process.

4.2.11 Other Existing Firm Capacity Power Purchase Agreements

HECO's PPA with Kalaeloa Partners, L.P. ("KPLP") for 208 MW of firm capacity expires on May 23, 2016. Also, HECO's PPA with AES Hawaii expires on September 1, 2022 and HECO's PPA with H-Power expires on July 31, 2015. While HECO has not yet decided on the means to acquire the capacity that would be lost with the expiration of the

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[15] In certain situations, such as when HECO needs to determine avoided costs or needs to determine the cost-effectiveness of various resources, a specific "benchmark resource" with specific costs and performance characteristics is needed to represent the resource in the 2022 timeframe. Until the appropriate type of firm capacity generating unit needed in the 2022 timeframe is re-evaluated in IRP-4, a 180 MW coal unit will continue to be used as the benchmark resource in these situations.

PPAs, §II.A.3.g.(v) of the Framework for Competitive Bidding provides that "renegotiations of power purchase agreements in anticipation of their expiration, approved by the Commission," are exempt from the Framework. The issue of the appropriate replacement capacity and the means to secure the replacement capacity will be the subject of analysis in HECO IRP-4.

4.2.12 Risk Mitigation Measures

In light of the anticipated reserve capacity shortfall from 2005 to 2009 as described in Sections 2.5.6 and 9.10 of HECO's IRP-3 report, HECO identified a number of risk mitigation measures to pursue in order to help prevent the capacity shortfall or reduce its impact. The potential need for risk mitigation measures was introduced in Sections 11.8 and 11.9 of HECO's IRP-3 report. The action plans incorporating some of the risk mitigation measures HECO plans to pursue were described in Section 15.4 of HECO's IRP-3 report and in the 2006 AOS Report, and the status was updated in Appendices 3 and 4 of the 2007 AOS Report.

As stated in Section 15.4 of HECO's IRP-3 report, HECO's action plans and risk mitigation measures are not intended to be a single plan of action. Instead, they are meant to be part of a process to continuously re-evaluate, re-assess, and modify the appropriate actions and measures that should be taken in response to changing circumstances.

4.2.13 Contingency Planning

As stated in Section 15.4.1.6 of HECO's IRP-3 report and in its AOS Reports, and consistent with its parallel planning responsibility under the Competitive Bidding Framework, HECO has taken steps to be in a position to install a second 110 MW biofueled simple cycle combustion turbine if needed to meet near-term firm capacity needs, and HECO will continue to take steps to maintain this unit as a viable option unless circumstances change and there is reasonable assurance that the combustion turbine will not be needed to meet near-term firm capacity needs.

5. CONCLUSION

The key forecasts and planning assumptions used in IRP-3 were reviewed and it was determined that events since the IRP-3 filing on October 25, 2005 have overcome the plan. Accordingly, this evaluation report provides the updated planning assumptions and the resulting updated IRP-3 plan and Action Plan.

This updated IRP-3 plan identifies steps to address the near-term reserve capacity shortfall and meet customer energy needs. It also facilitates achievement of the Renewable Portfolio Standard through future renewable energy supply-side resources.

This evaluation report is not intended to be a complete review of the IRP-3 plan; rather it is intended as a starting point for HECO IRP-4. HECO will continue its analysis of the updated IRP-3 Plan and Action Plan in HECO IRP-4, which started with the Kickoff Advisory Group meeting on March 30, 2007. HECO will be working closely with the public through Advisory Group meetings, technical sessions, and public meetings to discuss concerns and preferences to be included in developing the IRP-4 Plan and Action Plan.