Hawaiian Electric Company
Maui Electric Company
Hawaii Electric Light Company

Hawaiian Electric Companies

2013 Integrated Resource Planning Report

28 June 2013

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Acknowledgement

The Hawaiian Electric Companies would like to thank the Independent Entity, the IRP Advisory Group members, and the Public Utilities Commission who contributed to the development of the 2013 Integrated Resource Planning Report.

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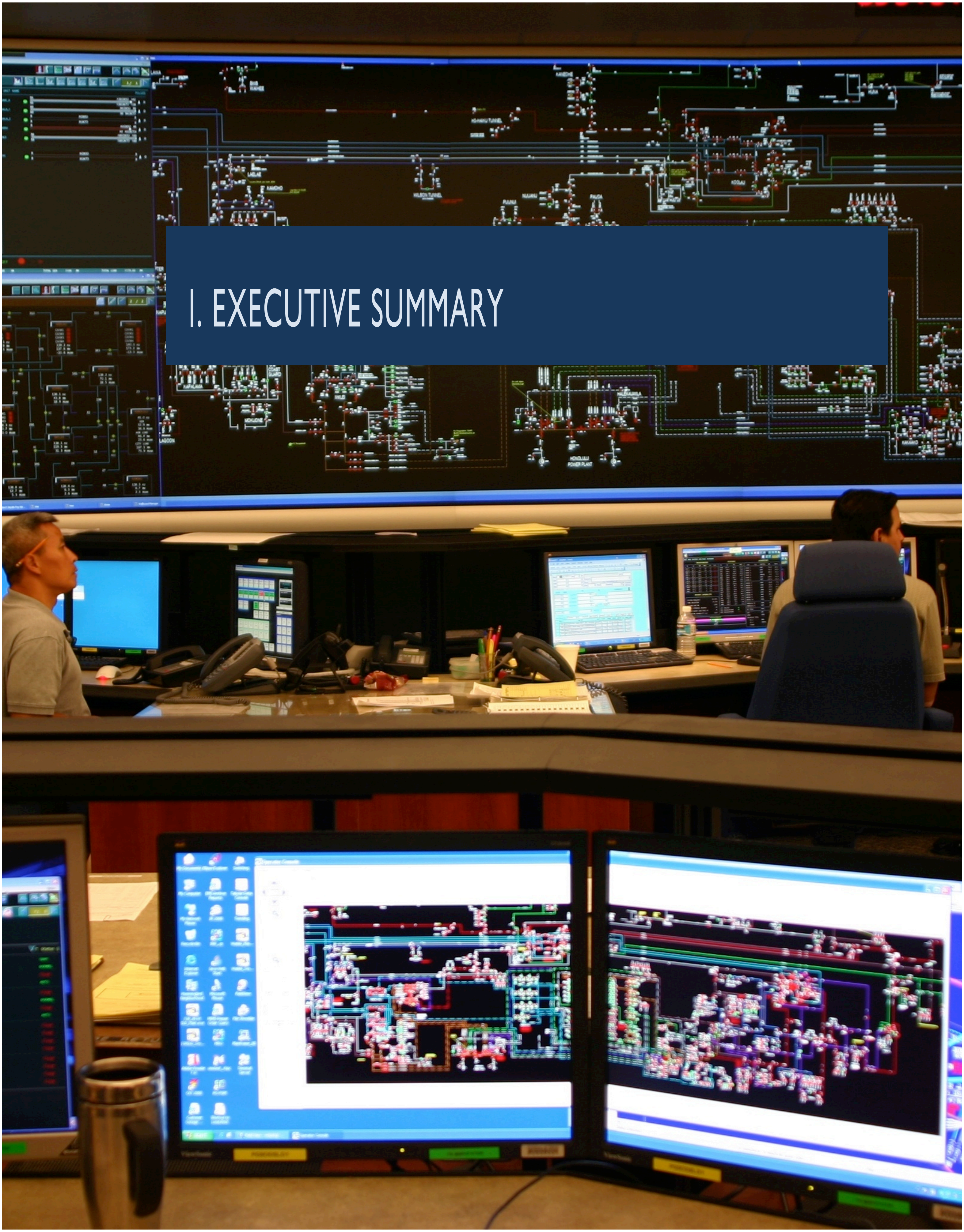
I. EXECUTIVE SUMMARY



Executive Summary

The Hawaiian Electric Companies are:

- Hawaiian Electric Company, Inc serving Oahu
- Maui Electric Company, Ltd serving Maui, Lanai, and Molokai
- Hawaii Electric Light Company, Inc serving the island of Hawaii

The Companies have developed the 2013 Integrated Resource Planning (IRP) Action Plan and report in cooperation with the Independent Entity and the Advisory Group established for this purpose by the Hawaii Public Utilities Commission in accordance with the IRP Framework.

Introduction

Hawaiian Electric Company, Hawaii Electric Light Company, and Maui Electric Company [collectively referred to as the Companies] have developed the 2013 Integrated Resource Planning (IRP) Action Plan and report in cooperation with the Independent Entity (IE) and the Advisory Group (AG) established for this purpose by the Hawaii Public Utilities Commission (Commission) in accordance with the IRP Framework.[1]

The general goal of IRP is to develop an *Action Plan* that guides how the Companies will meet energy objectives and customer energy needs consistent with State of Hawaii energy policies and goals. The 2013 IRP Objectives were developed with the AG, and are presented below:

- Protect Hawaii's culture and communities
- Protect Hawaii's environment
- Provide electricity at a reasonable cost
- Reduce dependency on imported fossil fuels and improve price stability
- Increase the use of indigenous energy resources
- Provide reliable service
- Improve operating flexibility.

Historically, a traditional IRP would assess the new generation resource needs for a nominal 20-year planning period in a fully-regulated market with increasing demand for generation capacity. This is not the case in Hawaii today. Due to high fuel costs, effective energy efficiency programs, customer self-generation of electricity and economic conditions, utility sales and peak loads have declined for several years and are expected to be relatively flat (Stuck in the Middle IRP Scenario) or continue to decline (Blazing a Bold Frontier IRP Scenario) in the future. The composition, configuration, and operations within the electric power sector in Hawaii are changing dramatically. Consequently the IRP process has new challenges, including:

- Lowering costs to customers
- Meeting the Renewable Portfolio Standards
- Complying with more stringent environmental regulations
- Supporting achievement of Energy Efficiency Portfolio Standards
- Facilitating customers' preferences, including customer-sited generation

[1] Decision and Order, Public Utilities Commission of the State of Hawaii, "Instituting a Proceeding to Investigate Proposed Amendments To the Framework for Integrated Resource Planning," Docket No. 2009-0108, March 14, 2011.

- Capitalizing on technology evolutions and price decreases for energy resources

The local and global energy environments are dynamic, changing rapidly and unpredictably. Accordingly, the IRP must develop Action Plans with the flexibility to accommodate this dynamic future.

The Companies' goal is to better understand and respond to our customers' preferences and priorities. Our relationship with our customers begins in their homes and their businesses — helping them to conserve energy, to take advantage of energy efficiency and distributed generation options like PV, and to provide them the most information and the greatest control of their electricity use possible through tools such as smart meters and energy education. We also must continue to live up to our responsibility to ensure safe and reliable service for our customers' homes and businesses, in whatever manner and from whatever source our customers choose.

Overview: Hawaiian Electric Companies' Integrated Resource Plan

Focus on Customers

The price of electricity in Hawaii has increased significantly in the past several years and our customers expect the Companies to develop and implement an IRP Action Plan that will help lower their electricity bills. This will be accomplished by: (1) Reducing the utility's cost to generate, transmit, and distribute power; (2) Providing customers with information to enable better choices regarding their energy use; and (3) Facilitating customers' ability to generate their own power using rooftop PV.

For the first area of focus, the Companies recognize that they must make every effort to eliminate their dependency on imported oil for power generation. This will involve:

- Accelerating the deactivation/Decommissioning of older, oil-fired steam generators.
- Procuring or developing low-cost, fast track utility-scale renewable energy resources.
- Converting existing generating units to cost effective renewable and lower carbon fuels, including biomass, biofuels, and liquefied natural gas.

For the second area of focus, customers will be able to lower bills by taking advantage of information and education from the companies and by using smart meter technology (on an optional basis) to make better choices about their energy use. The Companies are committed to all-island, island-wide deployment of smart meters (with opt-out provisions) by 2017–2018, and by providing new Demand Response programs through which customers can support clean energy while lowering their own bills.

For the third area of focus, through the implementation of new processes and technologies to interconnect distributed PV, the Companies will be proactively performing the engineering studies and implementing the necessary utility system upgrades to accommodate more distributed generation on distribution circuits that have or are projected to have high concentrations of distributed generation. This will reduce the costs of the studies and upgrades to customers installing PV and provide for more uniform, timely, and unfettered access for all customers to interconnect on a given circuit.

The Companies are also committed to improved service for our customers. The IRP will implement actions to improve reliability — meaning fewer, shorter service interruptions. And when a service interruption occurs, the new Outage Notification System and Smart Grid Distribution Automation will result in more timely and accurate communications with our customers, and faster restoration of service.

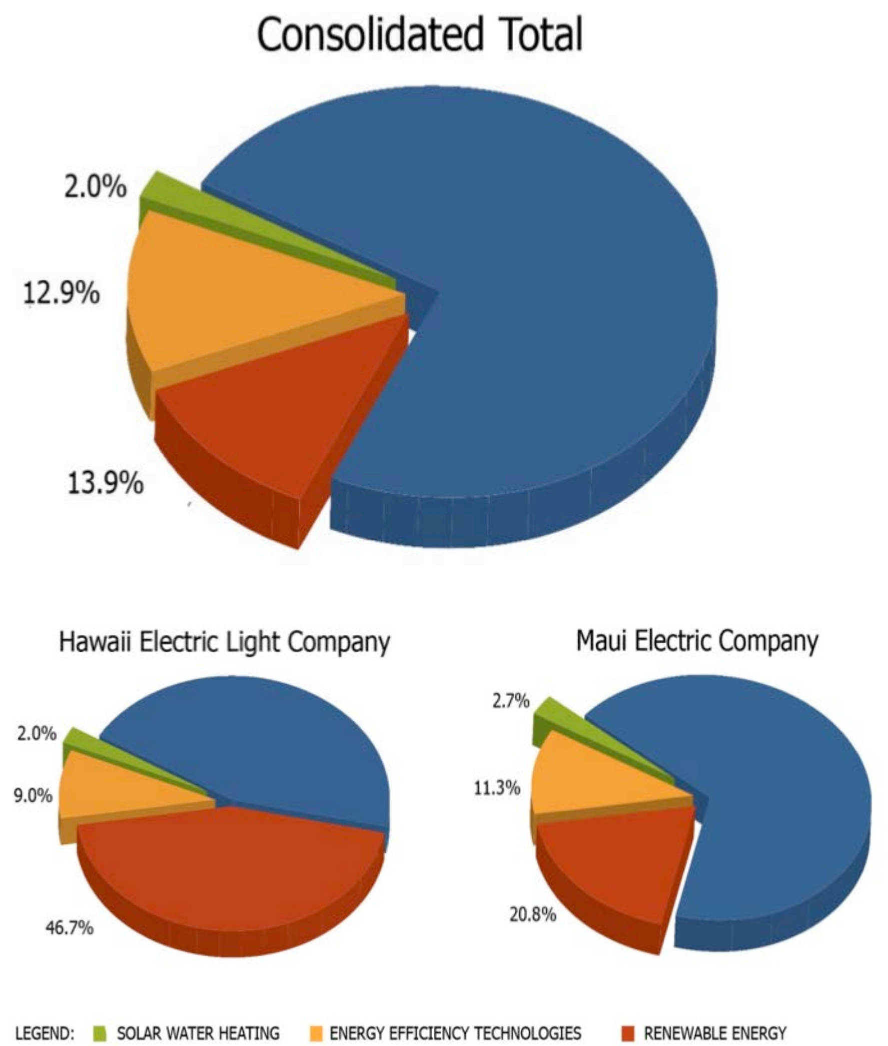
Clean, Renewable Energy is Our Foundation

Under Hawaii's Renewable Portfolio Standard (RPS), the Companies must meet the following percentages of "renewable electrical energy" sales:

- 10% of net electricity sales by December 31, 2010;
- 15% of net electricity sales by December 31, 2015;
- 25% of net electricity sales by December 31, 2020; and
- 40% of net electricity sales by December 31, 2030.

The Companies met a record 13.9% of energy needs from renewable generation in 2012 – well ahead of the 12% reported for 2011 and on the way to passing the next clean energy goal of 15% in 2015.

Figure ES-1. Consolidated Hawaiian Electric Companies 2012 Renewable Portfolio Standards



The achievements of 46.7% and 20.8% on Hawaii Island and in Maui County, respectively, have been major contributors to the consolidated total. Rooftop and utility-scale solar photovoltaic facilities on all islands, more wind energy on Oahu and Maui, and increased geothermal energy production on Hawaii Island all contributed to this progress.

By the end of 2013, we expect to achieve 18% renewable energy, twice the percentage of just five years ago and well ahead of the 2015 Renewable Portfolio Standard goal of 15%.

Correspondingly, the Companies have cut oil use by 500,000 barrels a year, avoiding spending $69 million for oil in 2012. Including energy efficiency, Hawaii now uses almost one million barrels less per year compared 2008.

In total, as shown in Table ES-1, the Companies have over 600 MW of renewable capacity in service that produced more than 1,250,000 MWh in 2012.

Table ES-1. Renewable Projects in Service (End-of-Year 2012)

Project and Island	Nameplate MW	MWh/year (2012 data)
Customer-sited Distributed Generation (mostly solar)		
Oahu	100.6	125,882
Maui County	25.8	28,474
Hawaii Island	19.9	28,282
Feed-in Tariff		
Oahu	4.2	3,787
Maui County	1.4	1,143
Hawaii Island	0.5	213
Waste-to-Energy		
Oahu: HPOWER	72	301,197
Oahu: AES		1,202
Biofuel		
Oahu: Campbell Industrial Park Generating Station	110.0	21,259
Maui: Miscellaneous MECO		1,348
Wind		
Oahu: Kawailoa Wind	69.0	22,937
Oahu: Kahuku Wind (temporarily out of service)	30.0	52,472
Maui: Kaheawa Wind	30.0	121,251
Maui: Kaheawa Wind II	21.0	33,700
Maui: Sempra Auwahi Wind	21.0	3,206
Hawaii Island: Tawhiri	20.5	111,903
Hawaii Island: Hawi Renewable Development	10.5	42,785

Project and Island	Nameplate MW	MWh/year (2012 data)
Utility-Scale Solar		
Oahu: Kalaeloa Solar II	5.0	188
Oahu: Kapolei Sustainable Energy Park	1.0	1,928
Lanai: La Ola Solar	1.2	2,351
Hawaii Island: Keahole Solar	0.5	31
Geothermal		
Hawaii Island: Puna Geothermal Venture	38.0	266,234
Biomass		
Maui: Hawaiian Commercial and Sugar (HC&S)	16.0	39,392
Hydroelectric		
Maui: Makila Hydroelectric	0.5	591
Maui: Hawaiian Commercial and Sugar (HC&S)	6.0	6,861
Hawaii Island: Wailuku River Hydroelectric	12.1	26,799
Hawaii Island: Waiau Hydroelectric	1.1	7,930
Hawaii Island: Puueo Hydroelectric	3.3	21,010
Hawaii Island: Small Hydroelectric		1,875
	Estimated MW	*MWh/year*
Total: Oahu, Maui County, and Hawaii Island	*621*	*1,276,231*

In addition, as shown in Table ES-2, there are potentially more than 1000 MW of renewable energy projects under construction, awaiting approval, in negotiation or planned for solicitation. Although ultimately not all of the listed projects may be developed due to viability or cost-effectiveness challenges, other renewable projects could evolve to take their place. The theoretical amount of energy that could be produced from all of the listed projects and solicitations is more than 2,200,000 MWh/year.

Table ES-2. Renewable Projects in Progress

Project Name	Nameplate Capacity (MW)	Estimated MWh/Year
Renewable Energy RFPs in development		
Oahu: Non-firm renewable energy request for proposals	200	700,000
Oahu: Firm renewable energy request for proposals	200	TBD
Maui County: Firm renewable energy RFP	50	TBD
Waste-to-Energy/Fuel		
Oahu: Honua Power (PPA approved; construction pending)	6	53,000
Maui: Maui County waste-to-fuel	TBD	TBD
Hawaii Island: Prospective County project	TBD	TBD

Project Name	Nameplate Capacity (MW)	Estimated MWh/Year
Biofuel		
Oahu: Honolulu International Airport Emergency Generating Station (under construction)	8	3,000
Oahu: Schofield Barracks distributed generation	Approx. 50	44,000
Wind		
Oahu – low-cost project awaiting waiver from competitive bidding	21	74,000
Lanai Wind (requires undersea cable bid as part of a separate RFP) (PPA under negotiation)	200	778,000
Utility-Scale Solar		
Oahu: Low-cost projects awaiting waiver from competitive bidding	43	64,000
Oahu: Kalaeloa RE Park (PPA under negotiation)	5	7,000
Oahu: Mountain View PV (PPA to be negotiated)	5	7,000
Oahu: Kalaeloa Solar One (PPA to be negotiated)	5	5,000
Oahu: Kalaeloa Home Lands (PPA to be negotiated)	5	7,000
Oahu: Mililani South PV (PPA under negotiation)	20	27,000
Oahu – Actus Sunpower (PV) (PPA to be negotiated)	5	7,000
Oahu: HCDA Projects (PV) (PPA to be negotiated)	5	7,000
Geothermal		
Hawaii Island – Geothermal RFP	50	389,000
Biomass		
Hawaii Island: Hu Honua Biomass (PPA submitted, awaiting approval; in construction)	21.5	107,000
Hawaii Island: Tradewinds Biomass (PPA negotiated but not at PUC yet)	3.6	TBD
Maui –Mahinahina Biomass (waiver application submitted)	4.5	TBD
Ocean Thermal Energy Conversion		
Oahu – OTEC International (PPA under negotiation))	100	TBD
Total: Oahu, Maui County and Hawaii Island	*1007.6*	*2,279,000*

The sum of energy produced by renewable energy for projects in service in 2012 plus projects in progress is estimated to total more than 3,500,000 MWh/year, which based on current total sales would represent 38% RPS, very nearly the 40% the requirement for 2030. For comparative purposes, the Companies' sales in 2012 are summarized below:

County	**MWh**
Oahu	6,975,996
Maui County	1,144,832
Hawaii Island	1,085,171
Total	9,205,998

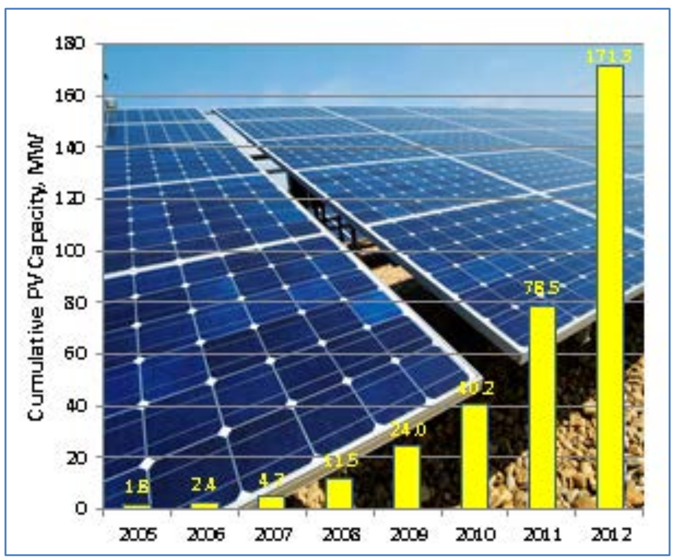
Distributed Solar

By far the most striking renewable energy growth is for rooftop solar taking advantage of the Companies' net energy metering (NEM) program. A growing and extremely competitive solar power industry has developed, with customers responding to record high electricity prices in Hawaii, generous state and federal tax credits, and declining costs for solar panels nationally and globally. Hawaii added 12,215 solar systems on Oahu, Maui County and Hawaii Island in 2012, exceeding the previous 10 years combined.

In addition, the Companies' Feed-In Tariff (FIT) offers pre-set rates and standardized contract terms for individuals, small businesses or governmental entities to sell renewable energy to the Companies. Solar, wind, hydro or biomass projects having a capacity of 5 MW or less on Oahu, and 2.9 MW or less on Hawaii Island and Maui County are eligible for FIT. As of May 2013, there have been 101 FIT projects installed at a cumulative capacity of 12.02 MW. There are an additional 201 FIT projects currently being processed for a potential capacity of 103.3 MW.

As shown in Figure ES-2, rooftop solar on the Companies' grids have doubled in capacity each year since 2008. It is on track to double or nearly so in 2013.

Figure ES-2. Hawaiian Electric Companies Consolidated Cumulative PV Capacity Additions



Hawaii's solar success is undisputed. The Hawaii utilities are at the top in the nation in the number of PV systems per customer. More than 5 percent of Hawaiian Electric and Maui Electric customers and more than 4 percent of Hawaii Electric Light customers had solar systems as of December 2012. By comparison, on much larger grids, San Diego Gas & Electric and Pacific Gas & Electric each have only about 1.5 percent of customers with PV systems.

Table ES-3. Solar Penetration Based on Number of Utility Customers

2012	2011	Utility	Solar Systems per Customer*
1	1	Maui Electric Co. (HI)	5.4%
2	2	Hawaiian Electric Co. (HI)	5.2%
3	4	Hawaii Electric Light Co. (HI)	4.2%
4	5	Kauai Island Utility Co-op (HI)	3.1%
5	3	Roseville Electric (CA)	2.4%
6	6	Verendrye Electric Co-op (ND)*	1.9%
7	7	City of Palo Alto Utilities (CA)	1.8%
8	9	Sulphur Springs Valley Electric Co-op (AZ)	1.7%
9	11	San Diego Gas & Electric (CA)	1.52%
10	10	Pacific Gas & Electric (CA)	1.49%

*Solar Electric Power Association 2012 Solar Utility Rankings Report

Utility-Scale Solar

As prices for solar technologies continue to drop, the cost for utility-scale solar projects has become more competitive. Projects totaling 43 MW at an average price of $0.16/kWh were recently submitted to the Commission in a request for a waiver from competitive bidding. Additional waiver requests for similar low-cost, fast track projects may be forthcoming for a variety of projects, including those that result from the Companies' competitive solicitation(s), the Companies' self-build utility-scale PV project at Kahe Power Plant, and the other self-build projects that the Companies may develop. If the waiver requests are approved by the Commission, substantially more utility-scale solar capacity on Oahu is expected to result.

Utility-Scale Wind

In the past year, 111 MW of utility-scale wind was added to the Companies' grids, and a proposal for an additional 21 MW has been submitted to the Commission in a request for a waiver from competitive bidding. The Companies have a term sheet in place and are negotiating a power purchase agreement for a 200 MW wind energy project on Lanai that would be interconnected via undersea cable to the Oahu grid. The Companies are also committed to numerous initiatives to minimize curtailment of wind energy, including:

- Increased turndown and cycling of steam generation units
- Utilization of battery energy storage systems
- Deactivation of old oil-fired steam generation
- Increased use of wind forecasting tools
- Use of quick-starting diesel engines for frequency regulation

- Optimization of regulating reserve requirements
- Utilization of Demand Response techniques for frequency regulation
- Optimized scheduling of power line construction and maintenance

Waste-to-Energy

On Oahu, the capacity of the existing County waste-to-energy project was recently increased by more than 55% to 72 MW, and a separate 6 MW project is being developed. Other smaller-scale projects are under consideration on Maui and Hawaii Island.

Geothermal

There is currently 38 MW of geothermal capacity on Hawaii Island, and a competitive solicitation for up to an additional 50 MW is in progress.

Biomass

A 16 MW biomass power plant continues to operate on Maui[2], and a new project is under construction on Hawaii Island for an additional 21.5 MW. Conversion of Hawaii Electric Light's 15 MW oil-fired steam generator at Puna is also under consideration for conversion to biomass operation.

Biofuel

Two biofuel contracts, one national and one local, have been approved by the Commission and contracts for 26,000,000 gallons of biofuel annually are under Commission review. These fuels would displace imported oil, and would be deployed as follows:

- Keahole Power Plant would consume 16,000,000 gallons/year of biodiesel displacing diesel oil and producing 215,000 MWh/year (pending Commission approval)
- Honolulu Airport Emergency Generating Station is expected to consume 250,000 gallons/year of biodiesel and produce 3,000 MWh/year once placed into service at the end of 2013
- Kahe Power Plant would consume 10,000,000 gallons/year of biofuel displacing low sulfur fuel oil and producing 142,000 MWh/year (pending Commission approval)
- The planned Schofield Distributed Generation project would more efficiently consume 3,000,000 gallons/year of biodiesel (pending submittal of an application and Commission approval). Pending Commission concurrence, redeployment of the biodiesel currently used at CT-1 to the Schofield Distributed Generation project would produce approximately twice as many net MWh at Schofield compared to CT-1 operating in a simple-cycle mode

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[2] The HC&S plant has a capacity greater than 16 MW and is not exclusively fired on biomass. The PPA has a capacity of 16 MW.

Technologies Continue to Evolve

Evolving technologies continue to enable more renewable energy. The continuing decreases in prices for solar, wind, and energy storage result in more projects competing for opportunities to interconnect to the Companies' grids at competitive prices. Moreover, the availability and optimal use of improved system operation methods, quick-start engines, demand response, wind and solar forecasting tools, and energy storage will result in higher capacity factors (and less curtailment) of renewable resources.

Prospects for RPS Compliance

Based on the estimated renewable energy production and sales for the Companies' three Preferred Resource Plans, the consolidated RPS percentage was calculated for each year of the planning period. This assumes that all projects included in the Action Plans in the Preferred Plans are developed and placed into service. As shown in Figure ES-3 and Figure ES-4, the consolidated RPS percentage for the Blazing a Bold Frontier and Stuck in the Middle scenarios predict RPS greater than 40% in 2018 and 2022, respectively. This would provide a considerable margin for compliance for both scenarios compared to the compliance date of 2030.

Figure ES-3. Consolidated RPS Sales Percentage Preferred Plans: Blazing a Bold Frontier

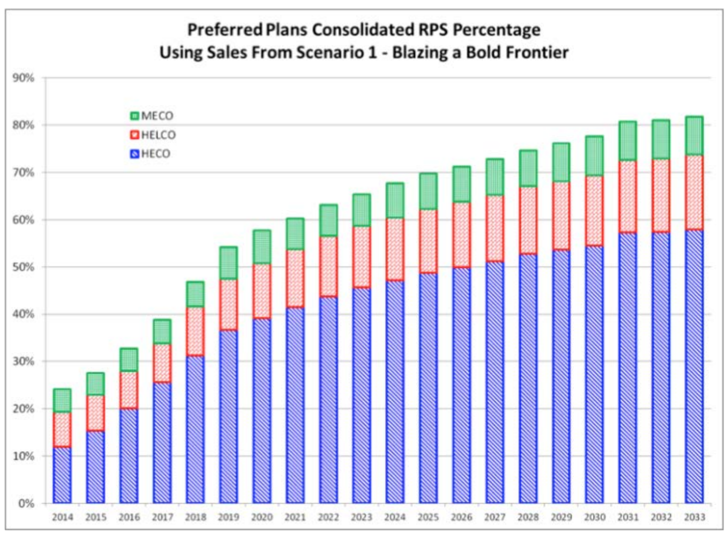
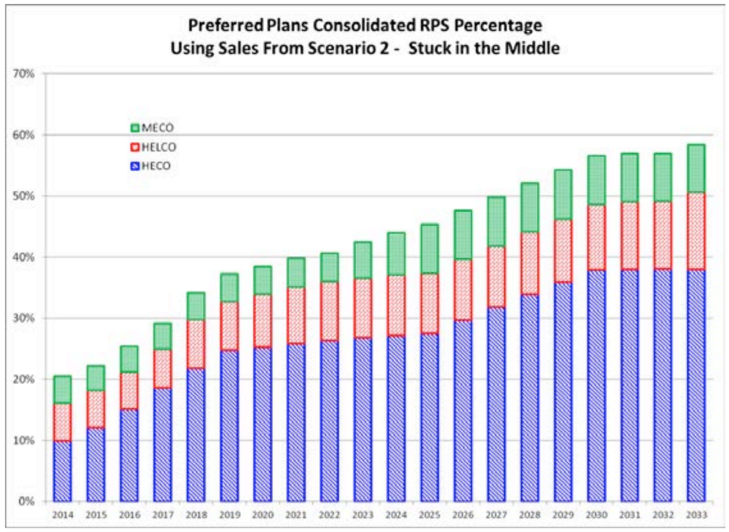


Figure ES-4. Consolidated RPS Sales Percentage Preferred Plans: Stuck in the Middle



Based on the Preferred Resource Plans, this analysis suggests that in these scenarios, an RPS greater than 40% would be realized well before 2030 with all the renewable energy sources operating and supplying energy solely to grids on the respective islands on which they are located. This does not include any inter-island power generation and transmission via inter-island undersea cables.

A key concept underlying the Companies' commitments to clean energy in 2008 was the understanding that much of Hawaii's developable renewable energy resources are located on islands other than Oahu, but the primary load that can utilize electricity generated from those resources is on Oahu. For example, Hawaiian Electric had received two proposals for large wind farms on Lanai and Molokai in response to its 2008 Renewable Energy RFP. Energy from renewable energy generators on islands other than Oahu would have to be delivered to Oahu by undersea cable systems (such as those systems already in service around the world) that either directly connect the generators to the Oahu system, or that connect the systems on Oahu and the other islands.

In the dynamic energy word, much has changed since 2008. Most of the electricity produced to serve Hawaii's needs is still generated from oil-fired dispatchable generation, but as discussed above the transition to lower-cost renewable energy is advancing rapidly. Moreover, challenging economic conditions, incentives for energy efficiency, high electricity prices and substantial tax incentives for customer-sited PV systems, have combined on all islands to reduce system loads and sales. The only certainty is uncertainty.

As a result, the Companies' focus and strategies with respect to acquiring new supply-side resources have to change as well, while accounting for the continued uncertainty about future energy conditions. On Oahu, Hawaiian Electric's focus is on continuing to acquire renewable energy resources, while lowering the cost of electricity on Oahu in both the near term and the longer term by: (1) Deactivating or decommissioning older, less efficient generating units at the Honolulu and Waiau Power Plants, (2) taking advantage of currently available, lower cost intermittent renewable generation through waiver requests and RFPs, and (3) acquiring liquefied natural gas (LNG) — a cheaper, cleaner fuel to substantially reduce emissions from displaced oil while transitioning to a renewable energy future.

On the island of Hawaii, Hawaii Electric Light has the opportunity to acquire new, dispatchable, renewable generation by purchasing power from the planned Hu Honua biomass-fired facility, and acquiring new geothermal-sourced power through its current geothermal RFP. Subject to Commission approval, biofuels may displace diesel at the Keahole Power Plant.

On Maui, three wind farms now provide up to 72 MW of wind energy, and the challenge is for Maui Electric to continue to change its system and how it is operated to be able to accept more of the electricity generated by the wind farms. At the same time, Maui Electric is committed to retiring its Kahului Power Plant (KPP). Kahului Units 1 and 2 will be deactivated in 2014, and all four units will be decommissioned by 2019 or sooner when the transmission power lines in Kahului are upgraded. KPP provides 36 MW of firm capacity and system support for a 23 kV system, and Maui Electric must take the steps necessary to replace this capacity in a cost-effective manner (looking at not only new generation, but also at energy storage, demand response resources, and the potential capacity value of as-available resources such as wind), while transitioning the way in which HC&S supplies power.

On Lanai, the IRP analysis suggests that a combination of utility-scale PV with battery energy storage or a biomass-fired generator could potentially reduce costs and increase local renewable energy resources. Pending more detailed analysis of specific project plans, Maui Electric will work collaboratively with the Lanai community and Lanai Resorts to create a plan to develop the resources.

On Molokai, Maui Electric will be conducting more detailed resource assessments and a system impact study for a biomass-fired generator and utility-scale PV with energy storage. If the results confirm that biomass and/or utility-scale PV with energy storage are cost-effective and increase local renewable energy for Molokai, then Maui Electric will work collaboratively with the Molokai community to create a plan to develop the resources.

The viability of inter-island renewable energy power projects needs to be tested in the marketplace, with the first step being issuance of an RFP by Hawaiian Electric to determine the costs of interisland renewable resources and transmission to Oahu. As discussed above, inter-island power is likely not needed for RPS compliance. However, inter-island projects may prove to be more economical than projects on Oahu, and the best way to determine this is through a competitive solicitation.

Non-Renewable Energy Generation and the T&D System

The core of the Companies' future generation mix will be renewable energy, much of which is intermittent and not possible to schedule. For reliable system operation, the balance of the generating units and grid devices (for example, energy storage) must have different operating attributes than those commonly associated with baseload generation. In general, the majority of these generating units would provide the ancillary services needed for system operation, and include attributes such as:

- Dispatchable (that is, able to schedule, commit, and load)
- Quick-starting capability
- Frequency regulation
- Voltage regulation
- Fault "ride through"
- "Tunable" droop response
- Turndown to lower minimum loads
- Daily and seasonal cycling
- Higher thermal efficiency at all load points (that is, lower heat rates)

Generally speaking, a generating unit with these attributes burns fuel. The fuels could be renewable (that is, biomass or biofuel) or fossil (that is, coal, oil, or gas).

Accordingly, the IRP includes actions to transform the generation fleet from one dominated by baseload generating units that provide bulk energy, to one that has a mix of more flexible generators with attributes that meet the requirements of the operating the future electric system. The result would be a modernized generation system.

Modernizing Generation

The modernization of generation will include several categories of actions, including: (1) Deactivation/Decommissioning of older generating units; (2) Changes to the operating modes of existing generators; (3) Installation of new quick-starting, agile, efficient, multi-fuel engines; (4) Implementation of Demand Response; (5) Implementation of energy storage; and (6) Conversion of oil-fired generation to liquefied natural gas (LNG).

With the growth in renewable energy and declining sales in recent years, the capacity and load factors of existing generating units have decreased. For example, in the Adequacy of Supply report for Hawaiian Electric Company filed with the Commission in early 2013, the Reserve Margin[3] in 2012 was

[3] Table A1: Projected Reserve Margins, Adequacy of Supply for Hawaiian Electric Company, Inc., filed with the Hawaii Public Utilities Commission, March 28, 2013. Reserve Margin equals the sum of System Capability at Annual Peak minus System Peak, and, minus Interruptible load, divided by the sum of System Peak plus Interruptible load. For 2012, the System Peak was an actual value. For 2013 through 2022, the System Peak is an estimated value.

58%. The Reserve Margin in the succeeding years, assuming no deactivation of generating units, increases to 62%. In general, this level of Reserve Margin is greater than needed to reliably operate the system and avoid generation shortfalls which would result in customer service interruptions. Correspondingly, there are near-term opportunities to accelerate the deactivation and/or decommissioning of older, oil-fired generating units on the Companies' Oahu grid, and similarly on the grids on Hawaii and Maui. Accordingly, the IRP includes actions to deactivate and/or decommission generating units sooner than previously anticipated as summarized below:

Table ES-4. Deactivation/Decommissioning Schedule

Generating	Company	Deactivation/Decommissioning Date
Honolulu Unit 8	HECO	2014
Honolulu Unit 9	HECO	2014
Waiau Unit 3	HECO	2016
Waiau Unit 4	HECO	2016
Shipman Unit 3	HELCO	2014
Shipman Unit 4	HELCO	2014
Kahului Unit 1	MECO	2014
Kahului Unit 2	MECO	2014

The Companies will continue to review and report annually for each of their operating systems about their Adequacy of Supply. As necessary and appropriate, the deactivation/decommissioning of additional units will be accelerated. Conversely, if system conditions change, units that are deactivated would be candidates for reactivation on relatively short notice to avoid generation shortfalls. This could occur if there is a natural disaster (for example, hurricane or tsunami damage similar to the March 2011 event in Japan), a loss of generation due to the expiration of a power purchase agreement, and/or unexpected load growth.

In evaluating the adequacy of supply, the Companies will consider the capacity value of as-available generation. Various probabilistic calculation techniques can be used to estimate the capacity value of as-available generation. In addition, historical data are used to draw a correlation between the availability of generation from the as-available resources and the periods of peak demand on the system. Analyses performed on Maui system indicated that the aggregate capacity value of the three wind farms may be in the range of 4.5% to 13.4% of total nameplate rating, or between 3 MW and 9 MW. Maui Electric also found that for 50% of the hours during the priority peak period (from 5 pm to 9 pm), there was a total of zero output from the wind farms. Maui Electric will continue to collect and analyze hourly power output data from the three wind farms. Similar analyses will be conducted for the Hawaii Island and Oahu systems.

For the Companies' baseload generating units that are not deactivated or decommissioned, the IRP includes actions to change the operating attributes of the units so that they provide the ancillary services needed for reliable system operation. These activities will include changes to operating procedures, equipment, and controls to: (a) Convert baseload generating units to daily and/or seasonal cycling duty; (b) Increase the turn down capability to lower loads; (c) Increase the ramp rate capabilities in increasing or decreasing load output; and (d) Modification of turbine controls to allow tuning of the droop response.

The IRP also includes actions to add multi-fuel firing capability to its existing generating units. This would enable operation of the units on the lowest-cost, environmentally-compliant fuel whether oil, biofuel, or natural gas.

The IRP includes an action to convert Hawaiian Electric's CIP CT-1 located in Campbell Industrial Park from a simple-cycle combustion turbine operating on biodiesel, to a combined-cycle combustion turbine/steam turbine generating unit with the capability to operate on diesel oil, biodiesel, or natural gas. This action would be subject to the Commission's approval and a modification of the air permit.

The IRP includes an action for a new quick-start, agile, efficient, multi-fuel reciprocating engine plant of approximately 50 MW capacity to be located at Schofield Barracks, outside the Oahu tsunami inundation zone for improved energy security. A facility with these attributes will enable increased integration of intermittent renewable resources on the Oahu grid (and minimize the potential for energy curtailment). Similar facilities of this size and type will be solicited in accordance with the Competitive Bidding Framework.

Energy Storage and Demand Response resources are expected to play increasing roles in system operation as more intermittent renewable energy resources are added to the system. Battery Energy Storage Systems (BESS) will be implemented to help provide frequency regulation, and possibly voltage regulation depending where they are located.

Demand Response may similarly assist with frequency regulation, possibly relieving the duty of quick-start diesel, and in some circumstances deferring the need for new firm generation.

For the fuel-burning generation fleet (existing and future), LNG may be the lowest- cost fuel, and to the benefit of customers, may be substantially lower cost than ultra-low-sulfur diesel (ULSD). The use of ULSD may be necessary to comply with more stringent environmental regulations, and LNG would be an attractive alternative to more expensive ULSD. The IRP includes actions to equip existing facilities to safely transport and burn natural gas. The transition from oil to LNG will require new infrastructure in Hawaii for: (a) bulk receiving of LNG from ocean-going ships; (b) LNG storage[4]; (c)

[4] The infrastructure would be located on Oahu, and a "hub-and-spoke" system would also have to be built in order to deliver LNG to the neighbor islands. Infrastructure on the neighbor islands would have to be built for storage, regasification, distribution, and firing at generating facilities.

regasification from liquefied to gaseous natural gas; and (d) distribution of the natural gas to generating facilities.

The IRP does not include actions for the Companies to design, build, own, or operate the LNG infrastructure items (a), (b), and (c). However, in the best interests of its customers, the Companies will participate in the process to successfully bring LNG to Hawaii. Accordingly, based on analyses to date the Companies suggest that the preferred approach would be "floating infrastructure" (that is, on a ship) for storage and regasification, in part, because it appears to be the lowest cost alternative. Moreover, if circumstances change (for example, LNG is no longer cost competitive, or imported fuels are no longer needed in Hawaii), then the infrastructure is easily removed.

Within a few years, it is expected that the longer-term firm generation needs and the viability of LNG for Hawaii will be better understood. In approximately 2015–2016, in accordance with the Competitive Bidding Framework, the Companies would issue an RFP for new generation based on the forecasted adequacy of supplies for its operating systems, the value of replacing aging generation units with more-efficient new ones, the ability of Demand Response, energy storage, and the capacity value of wind to defer the need for firm generation, and the availability of environmentally-compliant fuels.

Modernizing the Transmission & Distribution (T&D) Systems

In concert with the actions to modernize generation, the Companies' T&D systems will be modernized. Although the energy storage, demand response, and quick-starting reciprocating engines discussed previously as part of the efforts to modernize generation have certain capacity value, they are also critical components of a modern, smart grid. Moreover, they are critically important tools for reliable system operation of a grid with substantial amounts of intermittent renewable generation.

An important goal of the Companies' IRP Action Plan is to transform the existing grid into a "smarter", more efficient, more reliable grid that integrates more renewable energy through the use of various technologies and capabilities. This smarter grid provides more information and options to customers with the overall goal of reducing costs and improving customer service. Central to achieving this goal will be the use of advanced metering infrastructure (AMI) to enable real-time communications between the customers and the utility. The initial smart meter deployments will be functionally and/or geographically targeted, however, the Companies are committed to island-wide deployment of smart meters (with a customer opt-out option) for Oahu, Maui County, and Hawaii Island by 2018, 2017, and 2017, respectively.

The IRP also includes actions that are pivotal to a successful smart grid deployment, upgrading of: (1) Telecommunications infrastructure and (2) Distribution Automation (DA). An upgraded telecommunications infrastructure is necessary to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, and other smart grid technologies. The first two and most critical elements of the Action for upgrading are:

- **Infrastructure and Electronics.** Key backbone fiber optic cables, high capacity microwave radios, and high-speed, high-capacity electronic equipment linking and providing service to critical company sites. Carries data traffic between all areas of the Company, including, but not limited to, all types of SCADA, Business IT LAN, Demand Response, Security Video, Advanced Metering, Mobile Radio, Protective Relaying, and Renewable Integration.
- **Communication links to Distribution Substations and Major Communication Sites.** Lower capacity, point-to-point communications which connect Distribution Substations, Utility Communication Sites, and other critical locations. The data to be transported includes Distribution SCADA, IT Hot-spots for Mobile Computing, Demand Response, Security Video, Advanced Metering, and Land Mobile Radio voice trunks.

Distribution Automation (for example, sensors, switches, breakers, and "artificial intelligence" devices) working in combination with an effective Outage Management System will result in early detection of outages, more accurate identification of the affected areas of outages, and remote and/or automated switching to reduce the number of affected customers. From the customers' perspective, DA will also result in shorter outage times, improved estimates of the estimated time for restoration, and automated communications/notifications regarding specific outages.

Traditional T&D infrastructure, including overhead and underground power lines, substations and relay protection equipment will continue to be designed and constructed to meet customers' needs, improve system reliability, and enable more renewable distributed generation.

The grid modernization work includes an effective and strategically-planned asset management program to address operational and reliability issues with aging infrastructure. An effective asset management program replaces/upgrades critical equipment (for example, transformers, circuit breakers, switches, wood poles, underground cables, steel structures, etc.) near the end of their useful life and prior to failure. The Companies are implementing effective asset management programs and these will be sustained at a steady and reasonable level of expense.

Support for Energy Efficiency

Although the Hawaiian Electric Companies are no longer the official administrators of the energy efficiency programs, the Companies remain committed to fully supporting the efforts of its customers and the Commission's energy efficiency contractor to lower the amount of energy being used. Among other activities, the Companies are active participants in the Commission's On-Bill Financing Working Group, formed as a result of the Commission's determination that on-bill financing for energy efficiency and other technologies is viable.

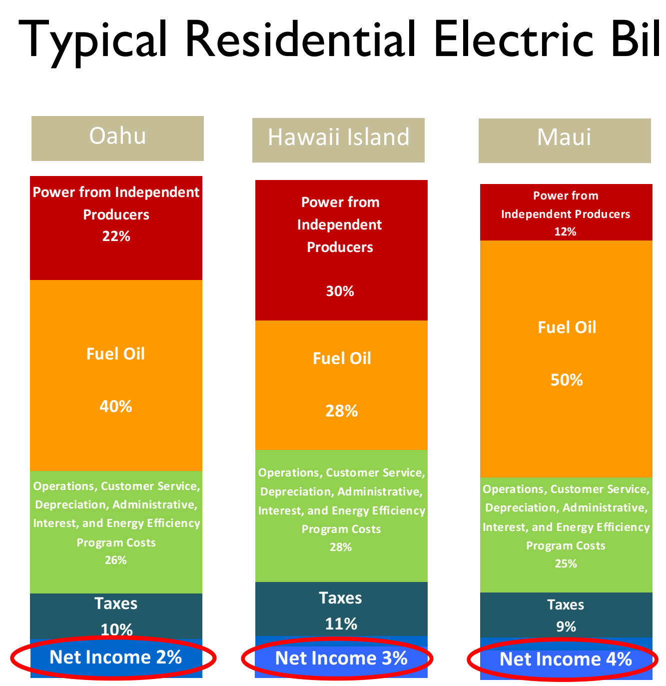
Costs

Stabilizing and lowering costs to customers is a critical goal for the Hawaiian Electric Companies. High energy costs, including electricity bills, are a tremendous burden for Hawaii's families and businesses.

Although discussions about resource options tend to focus on the generation costs, it should be noted that the total price customers pay reflects not only the cost of generating (or purchasing) the electricity, but also the costs of transmitting and delivering that energy, billing and processing service requests, acquiring, operating, maintaining and replacing the infrastructure that is necessary to ensure safe and reliable service, the substantial amounts of federal, state and county taxes paid by the Companies, compliance with environmental and other regulatory standards and mandates, and other costs for administration of operations that provide service to more than 450,000 customers.

However, by far, the biggest drivers of costs to customers are fuel and fuel-related purchased power costs, contributing to more than 50% of a typical bill. See for example, the breakdowns of an electric bill on Oahu, Hawaii and Maui as of January 2013:

Figure ES-5. Typical Residential Electric Bill (as of January 2013)



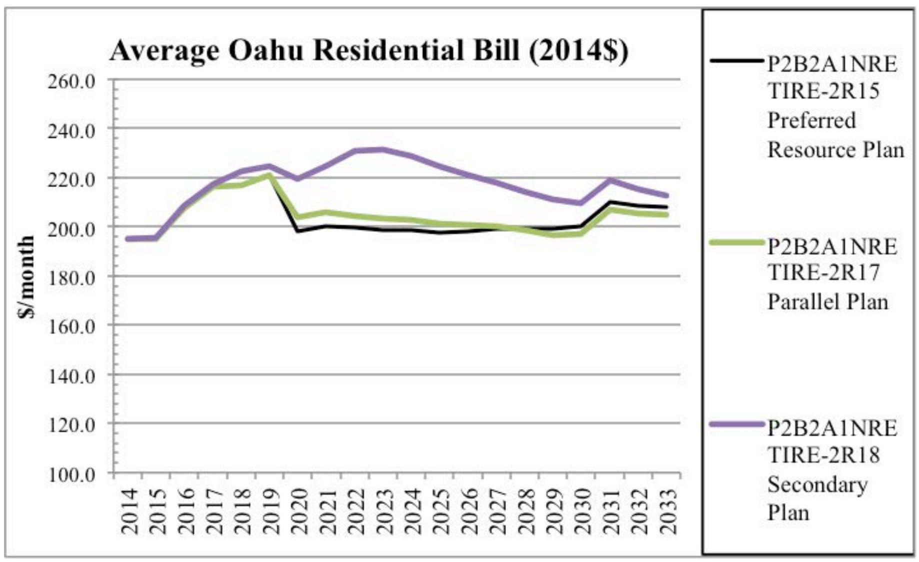
As noted in the Focus on Customer section, a core priority in the action plans for the Hawaiian Electric Companies is to provide their customers with better information and tools to help them control their energy costs and to responsibly facilitate the ability of customers to generate their own power, likely through photovoltaic systems.

Overall usage has been declining for many years and is expected to continue to decline with the successful implementation of these clean energy strategies. As customers gain greater control over their usage, this will help mitigate the overall cost to them (that is, their bill) and reduce that cost relative to what it would have been if the utilities maintained dependency on oil as the primary fuel.

There will be a growing number of customers who will be able to utilize the options and tools, as well as available incentives such as tax credits, to lower their usage and costs via energy efficiency and self-generation. However, as highlighted in the Fairness section, a smaller remaining base of customers will be left to pay for the fixed capital and operational non-energy costs of running the system. The graphs below reflect the blending of bill impacts for these two groups of customers.

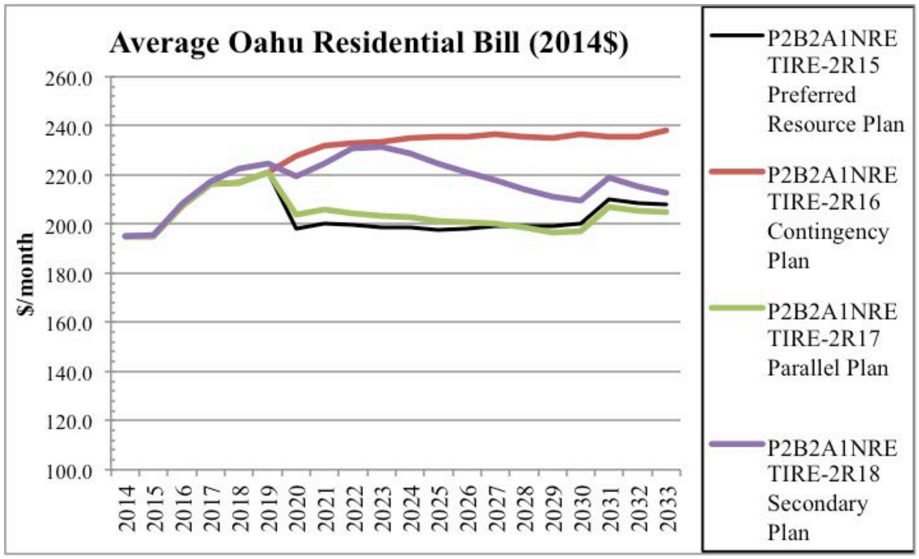
The graph below shows a hypothetical average residential Oahu bill in constant 2014 dollars under the preferred, parallel and secondary plans:

Figure ES–6. Average Oahu Residential Bill: Preferred, Parallel, and Secondary Plans



However, it is also important to view these bills relative to the higher levels they might be if the primary energy source in the future remains imported oil (contingency plan). This is depicted below.

Figure ES-7. Average Oahu Residential Bill: Contingency Plan



As a State, we must evaluate the cost to customers and the impact on our State's economy, as well as the benefit of reducing Hawaii's dependency on imported oil through State clean energy policies. The discussion must also address policies that impact fairness for all customers and other policies that contribute to higher energy costs for customers.

Fairness

The Companies' policies, programs, and tariffs, to the greatest extent possible, must be fair to all customers and those who do business with the utilities. Programs that favor one customer group over another, or practices that unfairly change the rules of the game on customers, need to be identified and corrected to strengthen the relationship that the Companies have with their customers. As the Companies move forward with actions to lower customer costs, advance clean energy, and modernize the grid, a governing principle will be ensuring fairness and looking out for the best interests of their customers.

In the traditional utility model, costs are allocated to customers based on the principles of cost causation and equity, under which costs incurred by the utility to provide service to a customer are paid for by that customer. This practice should be fairly applied to all customers. As the regulatory model has become more complex with certain customers generating portions of their own electricity and growing numbers of independent power producers (IPPs) seeking to sell electricity to the utility, a number of issues have been highlighted that should be addressed to allow these efforts to continue to thrive while being fair to all customers and energy suppliers. The Companies will evaluate its processes to look for ways to more fairly allocate costs to customers, and will support future program reviews as directed by the Commission.

For example, the rapid growth of distributed PV systems on the Companies' grids has led to issues of fairness within the community of PV owners. All power generating systems that are connected to the electric grid need to be reviewed by the utility to assure safety and electric reliability. When the number of PV systems on a neighborhood electric circuit is relatively modest, there are typically no safety or reliability concerns and early adopter PV customers can be quickly interconnected. As the number of PV systems grows, however, it becomes more likely that technical studies will be needed and potentially, that upgrades to the electric system will be required. The costs of these are to be paid by the interconnecting PV customer.

Thus, customers who interconnect their PV systems to an electric circuit earlier typically do not have to pay for the costs of interconnection studies or circuit upgrades. But customers currently seeking to install PV systems face a greater likelihood of having to pay for interconnection studies and potential equipment upgrades to the electric system. The Companies will support future Commission reviews of its interconnection tariffs to further improve on their fairness, such as reviewing whether the current "first-come, first-served" interconnection approach best serves the interests of all interconnected customers.

To mitigate the cost impact of such studies and upgrades on an individual customer, the Companies have uniformly adopted the practice of proactively studying and upgrading electric circuits to accommodate multiple PV customers, and will pro-rate the associated study and upgrade costs to customers as they request to install their PV systems. In this manner, costs will be spread across more customers and PV systems will be more efficiently interconnected. This approach is described in greater detail in *Chapter 16: Integrating High Penetration of Variable Distributed Generation.*

Chapter 16 also cites additional issues of fairness as identified in the Reliability Standards Working Group (RSWG) proceeding, Docket No. 2011-0206. For example, as more customers generate their own electricity, they leave fewer customers on the utility system to pay for the fixed capital and operational non-energy costs of running the system. Yet most customers who generate their own power remain connected to the utility system in order to receive electric service to supplement their power needs or to cover times when their generating systems are not operating due to clouds, darkness or maintenance. The growth in distributed PV is also beginning to raise concerns about collateral impacts on other renewable energy projects. The RSWG Independent Facilitator makes a number of recommendations to the Commission on opening new regulatory dockets to review these issues.

As an additional matter, the Companies' very successful Net Energy Metering (NEM) program allows customers to connect their renewable generator – typically photovoltaic (PV) systems – to the utility grid, allowing them to export surplus electricity into the grid, and to receive credits at the full retail price of electricity. The Companies strongly support the continued growth of the NEM program as an attractive option for their customers and an effective means of meeting their Renewable Portfolio Standard (RPS) goals. However, the Companies acknowledge that NEM customers, primarily residential, are being subsidized since providing credits at the full retail price of electricity far exceeds the cost that Hawaiian Electric saves in utilizing the energy that the NEM customer exports to the utility grid. The Companies' Feed-In Tariff program and Kauai Island Utility Cooperative's NEM Pilot program pay or credit the customer at a rate that is closer to the NEM customer's actual cost of generating the PV energy, which is much lower than the retail electricity price. The Companies will participate in and support Commission reviews of its energy procurement programs to improve their fairness and effectiveness in acquiring cost-effective clean energy for the benefit of all customers.

Scenarios, Resource Plans, and Action Plans

In accordance with the IRP Framework, "Scenario Planning" was adopted for the IRP process and implemented by the Companies. Four scenarios were selected for the IRP as being plausible representations of the future. By definition, unlikely outcomes (for example, nuclear power in Hawaii) were excluded from all four scenarios. As illustrated in Figure ES-8, the scenarios represent four quadrants of a two-by-two matrix defined by two axes: (1) Price of Oil, and (2) Public Policy on Renewables.

Figure ES-8. Scenario Matrix

During the analytical phase of the IRP process, the STRATEGIST computer program was used to evaluate alternative sets of assumptions for each scenario. For a given set of assumptions, STRATEGIST produced many Resource Plans in priority order based on cost. Among these many Resource Plans, the Companies ranked and descriptively prioritized final Resource Plans for each operating company. The final Resource Plans are labeled "Preferred Resource Plan," "Secondary Resource Plan," "Parallel Resource Plan," and "Contingency Resource Plan". These final Resource Plans are interpreted to bracket a range of reasonable plans that could unfold over the next twenty years. The final Resource Plans are presented in *Chapter 19: Action Plans*.

The Companies then defined an Action Plan for each operating company based on the final Resource Plans. It was not the intention to produce an Action Plan that is uniquely based on the Preferred Resource Plan (as is the case with traditional integrated resource planning), but instead to produce an Action Plan that best accommodates the range of plans defined by the four final Resource Plans.

The Action Plans cover the first five years of the IRP planning period (that is, 2014–2018). The Companies developed Action Plans which identify resource options and specific actions that will enable them to reasonably meet the IRP Objectives in light of Hawaii's uncertain future conditions and the challenges to the IRP process. The Action Plans contain elements of resources, programs and actions from all of the final Resource Plans. The Action Plans are summarized below for Hawaiian Electric, Hawaii Electric Light, and Maui Electric, and are presented in detail in Chapters 20, 21, and 22 of this report, respectively. Each Action Plan has organized the specific actions into four common themes:

- Lower Customer Bills
- Clean Energy Future
- Modernize Grid
- Fairness

Hawaiian Electric Action Plan (Oahu)

Lower Customer Bills

1. Deactivate and Decommission Generation

1.A. Honolulu 8 & 9 will be deactivated in 2014, and Waiau 3 & 4 will be deactivated in 2016.

1.B. Deactivating and decommissioning of additional units will be accelerated based on an annual analysis of adequacy of firm capacity to meet peak load.

1.C. If needed for emergencies and/or to mitigate generation shortfalls, selected units would be reactivated.

2. Lower-Cost Generating Facilities

2.A. An invitation (competitive solicitation) for "Waiver Projects" (low-cost, fast-track projects that can achieve commercial operation before the end of 2015) will be completed in mid-2013. The invitation requests utility-scale renewable energy projects on Oahu. Based on an evaluation of the proposals, the Companies will request approval from the Commission for waivers from the Competitive Bidding Framework.

2.B. Within a few years, it is expected that the longer-term firm generation needs and the viability of LNG for Hawaii will be better known. In approximately 2015–2016, the Companies will implement an RFP process for new generation based on the forecast adequacy of supply for the operating system, the value of replacing aging generation units with more-efficient new ones, and the availability of environmentally-compliant fuels. The attributes, size, fuel(s), and total capacity (MW) for the generating resources will be defined at that time, and will be subject to approval by the Commission. Adding new firm capacity is expected to allow deactivation/decommissioning of existing generating units.

2.C. CIP CT-1 would be converted from a simple-cycle combustion turbine operating on biodiesel, to a combined-cycle combustion turbine/steam turbine generating unit with the capability to operate on diesel oil, biodiesel, or natural gas. This action would be subject to the Commission's approval and a modification of the air permit.

2.D. The Kalaeloa Power, LLC power purchase agreement (PPA) expires at the end of 2016. In accordance with the approved waiver to the Competitive Bidding Framework, Hawaiian Electric will negotiate a new or extended PPA for approval by the Commission.

3. Environmental Compliance and Conversion to LNG or ULSD

3.A. To assure compliance with EPA's air regulations, the lowest-cost solution is to convert existing generation from burning sulfur-bearing fuels to LNG. The Companies would support the development of LNG infrastructure (import and regasification terminal) by another entity. The Companies would build new gas pipelines to deliver LNG to its power plants and would make modifications to their fuel burning equipment to accommodate LNG.

3.B. To assure compliance with EPA's air regulations when lower-cost LNG or biofuels are unavailable, the fuel burning and handling equipment at Kahe and Waiau Power Plants and the Barbers Point Tank Farm will be modified to accommodate ULSD.

3.C. The cooling water intake structures at Waiau and Kahe Power Plants would be modified to comply with pending EPA regulations under Section 316.b of the Clean Water Act.

3.D. A new pipeline for mixed fuel use would be designed and constructed between Kalaeloa Barbers Point Harbor and Hawaiian Electric's Barbers Point Tank Farm.

4. Other Projects to Lower Customer Bills

4.A. Hawaiian Electric will continue to develop and cultivate a portfolio of residential, commercial, and industrial loads for alternative Demand Response programs.

4.B. Baseload steam units at Kahe and Waiau Power Plants will be converted to daily/seasonal cycling operation, and equipment operating procedures will be modified for increased operational flexibility, to allow more intermittent renewable energy to be accepted on the Oahu grid.

4.C. Hawaiian Electric will continue to support the initiatives for attainment of the Energy Efficiency Portfolio Standards (EEPS)

4.D. Through competitive solicitations, Hawaiian Electric will continue to source low-cost biofuels.

Clean Energy Future

5. *Meet or Exceed Renewable Portfolio Standards*

5.A. Firm power resources (for example, dispatchable, high-efficiency, fast ramping, multi-fuel reciprocating engines) will be procured as part of the RFP process described for Hawaiian Electric Action 2.B. (above).

5.B. In accordance with the Commission's direction and the Competitive Bidding Framework, non-firm renewable energy will be procured for Oahu by implementation of an RFP process. The energy resources may be located on islands other than Oahu and energy transmitted by undersea transmission cable to Oahu.

5.C. Pending approval by the Commission, biofuels will be procured by contract with Hawaii BioEnergy.

5.D. To facilitate new distributed renewable energy resources to be interconnected to the Oahu grid, new transmission and distribution infrastructure will be design and constructed.

5.E. Hawaiian Electric will develop low-cost, fast-track, self-build utility-scale PV projects, including a project at Kahe Power Plant, for which it will seek a waiver from the Competitive Bidding Framework, subject to the Commission's approval.

5.F. Hawaiian Electric will continue to negotiate a power purchase agreement (PPA) for a wind power resource on Lanai (Lanai Wind), and, if a PPAC is executed, will submit the PPA to the Commission for review and approval. Lanai Wind would also require an undersea transmission cable from Lanai to Oahu, which would depend on Action 5.B (above).

5.G. Hawaiian Electric will implement all Reliability Standards Working Group (RSWG) actions that are approved by the Commission.

Modernize Grid — Oahu Island

6. *Improve Grid Operations*

6.A. Hawaiian Electric will seek Commission approval for a new quick-start, agile, efficient, multi-fuel reciprocating engine plant of approximately 50 MW capacity to be located at Schofield Barracks, outside the Oahu tsunami inundation zone for improved energy security. A facility having these attributes will enable increased integration of intermittent renewable resources on the Oahu grid (and minimize the potential for energy curtailment). The Commission has previously approved a waiver from the Competitive Bidding Framework for this project.

6.B. Hawaiian Electric will implement upgrades to its transmission and distribution system on Oahu for purposes of safety, reliability, environmental stewardship, and customer requests.

6.C. The existing grid will be transformed into a "smarter", more efficient, more reliable grid that integrates more renewable energy through the use of various technologies and capabilities and provide more information and options to customers with the overall goal of reducing costs and improving customer service. Central to achieving this goal will be the use of advance metering infrastructure (AMI) to enable real-time communications between the customers and the utility. The initial smart meter deployments will be functionally and/or geographically targeted, however, the Companies are committed to island-wide deployment of smart meters (with a customer opt-out option) for Oahu by 2018.

6.D. The telecommunications infrastructure on Oahu will be upgraded to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, smart grid technologies, and customer programs.

6.E. The companies will evaluate and implement energy storage resources on Oahu as a means to facilitate increased renewable energy (that is, reduced curtailment) and reliable system operation.

6.F. The dispatchable distributed generation project at the Honolulu Airport will be completed. The facility will operate on biodiesel.

Fairness

7. Address Questions with Existing Distributed Generation Programs

7.A. A uniform interconnection process will be implemented to facilitate more timely and uniform cost sharing among customers for interconnecting rooftop PV to distribution circuits.

7.B. Hawaiian Electric will continue to study, develop, and implement technical solutions to enable increased levels of distributed and utility-scale solar to be interconnected to the grid.

7.C. The Companies will support future Commission reviews of their interconnection tariffs to further improve on their fairness. This includes reviewing whether the current "first-come, first-served" interconnection approach best serves the interests of all interconnected customers.

Hawaii Electric Light Action Plan (Hawaii Island)

Lower Customer Bills

1. Deactivate and Decommission Generation

1.A. Shipman Units 3 and 4 will be decommissioned in 2014.

1.B. Deactivating and decommissioning of additional units will be accelerated based on an annual analysis of adequacy of firm capacity to meet peak load.

1.C. Deactivated generation will be reactivated if needed for emergencies and/or to mitigate generation shortfalls.

2. Lower-Cost Generating Facilities

2.A. Hawaii Electric Light will continue the implementation of an RFP process to procure up to 50 MW of geothermal energy on Hawaii Island.

2.B. Waiau Hydroelectric Power Plant will be repowered. The old 350 kW generator will be replaced with a 1.2 MW units, and the 750 kW generator will be refurbished to 800 kW.

2.C. Hawaii Electric Light will work collaboratively with the County of Hawaii or a private entity to develop waste-to-energy solution(s) in the Hilo Area.

2.D. Hawaii Electric Light will continue its efforts to renegotiate existing power purchase agreements to secure lower cost terms.

3. Replace Oil with Biomass and/or LNG

3.A. Hawaii Electric Light will develop a project to convert Puna Steam boiler from oil to biomass operation, including the securing of biomass feedstock, subject to approval by the Commission.

3.B. To assure compliance with EPA's air regulations, the lowest-cost solution is to convert existing generation from burning sulfur-bearing fuels to LNG. The Companies would support the development of LNG infrastructure to transport LNG from Oahu to Hawaii Island, and regasification and distribution systems on the Hawaii Island. Combustion equipment will be modified to fire natural gas.

4. *Other Projects to Lower Customer Bills*

4.A. Hawaii Electric Light will continue its Demand Response strategy to develop a portfolio of residential, commercial, and industrial customer loads that will enable reliable and economic operation of Hawaii Island's electric grid.

4.B. Hawaiian Electric will continue to support the initiatives for attainment of the Energy Efficiency Portfolio Standards (EEPS)

4.C. Hill 5 and 6 and their ancillary equipment will be modified to implement offline and deep (that is, very low load) cycling to better manage integration of lower cost renewable resources.

Clean Energy Future

5. *Meet or Exceed Renewable Portfolio Standards*

5.A. Hawaii Electric Light will implement all Reliability Standards Working Group (RSWG) actions that are approved by the Commission.

5.B. Subject to the Commission's approval of the Aina Koa Pono biofuel contract, generating units at Keahole Power Plant will be converted to firing biodiesel.

Modernize Grid — Hawaii Island

6. *Improve Grid Operations*

6.A. Hawaii Electric Light will implement upgrades to its transmission and distribution system on Hawaii Island for purposes of safety, reliability, environmental stewardship, and customer requests.

6.B. The telecommunications infrastructure on Hawaii Island will be upgraded to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, smart grid technologies, and customer programs.

6.C. The existing grid will be transformed into a "smarter", more efficient, more reliable grid that integrates more renewable energy through the use of various technologies and capabilities and provide more information and options to customers with the overall goal of reducing costs and improving customer service. Central to achieving this goal will be the use of advance metering infrastructure (AMI) to enable real-time communications between the customers and the utility. The initial smart meter deployments will be functionally and/or geographically targeted, however, the Companies are committed to island-wide deployment of smart meters (with customer opt-out option) for Hawaii Island by 2018.

Fairness

7. Address Questions with Existing Distributed Generation Programs

As described in the Action Plan for Hawaiian Electric (see 7.A., 7.B., and 7.C. on page ES-32), Hawaii Electric Light will work collaboratively with Hawaiian Electric and Maui Electric to implement the actions uniformly across the Companies.

Maui Electric Action Plan (Maui)

Lower Customer Bills

1. Deactivate and Decommission Generation

1.A. Kahului Units 1 and 2 will be deactivated in 2014. The engineering and installation of technology to lay the units will commence immediately.

1.B. Kahului Power Plant will be decommissioned by 2019.

1.C. Deactivating and decommissioning of additional units will be accelerated based on an annual analysis of adequacy of firm capacity to meet peak load.

1.D. Deactivated generation will be reactivated if needed for emergencies and/or to mitigate generation shortfalls.

2. Lower-Cost Generating Facilities

2.A. Maui Electric will evaluate and consider Demand Response, battery energy storage systems, capacity value of wind resources, and new firm generation to meet future needs for firm capacity in accordance with adequacy of supply analyses.

2.B. Maui Electric will continue negotiating a power purchase agreement (PPA) extension with Hawaiian Commercial and Sugar (HC&S). The PPA expires December 31, 2014. If successful, the PPA will be submitted for the Commission's approval.

3. Replace Oil with LNG

3.A. To assure compliance with EPA's air regulations, the lowest-cost solution is to convert existing generation from burning sulfur-bearing fuels to LNG. The Companies would support the development of LNG infrastructure to transport LNG from Oahu to Maui County, and regasification and distribution systems on the island(s) of Maui County. Combustion equipment will be modified to fire natural gas.

4. Other Projects to Lower Customer Bills

4.A. Maui Electric will continue to develop and implement a portfolio of residential, commercial, and industrial loads for alternative Demand Response programs.

4.B. Maui Electric will continue to support the initiatives for attainment of the Energy Efficiency Portfolio Standards.

4.C. Through competitive solicitations, Maui Electric will continue to source low-cost biofuels.

Clean Energy Future

5. Meet or Exceed Renewable Portfolio Standards

5.A. Maui Electric will implement all Reliability Standards Working Group (RSWG) actions that are approved by the Commission.

5.B. The existing regulating reserve policy for system operation of the Maui System will immediately be reviewed, with a view to reduce the regulating reserve requirements currently defined for varying levels of wind energy, and thus, reduce the curtailment of wind energy.

5.C. As stated in Action 2.A., Maui Electric will evaluate and consider Demand Response, battery energy storage systems, capacity value of wind resources, and new firm generation to meet future needs for firm capacity in accordance with adequacy of supply analyses.

Modernize Grid — Maui Island

6. Improve Grid Operations

6.A. Maui Electric will implement upgrades to its transmission and distribution system on Maui for purposes of safety, reliability, environmental stewardship, and customer requests. These actions will include the work necessary to allow retirement of Kahului Power Plant.

6.B. The existing grid will be transformed into a "smarter", more efficient, more reliable grid that integrates more renewable energy through the use of various technologies and capabilities and provide more information and options to customers with the overall goal of reducing costs and improving customer service. Central to achieving this goal will be the use of advance metering infrastructure (AMI) to enable real-time communications between the customers and the utility. The initial smart meter deployments will be functionally and/or geographically targeted, however, the Companies are committed to island-wide deployment of smart meters (with customer opt-out option) for Maui by 2018.

6.C. The telecommunications infrastructure on Maui will be upgraded to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, smart grid technologies, and customer programs.

6.D. Maui Electric will continue its efforts to create and implement an effect asset management program for its transmission and distribution infrastructure on Maui.

6.E. The companies will evaluate and implement additional energy storage resources on Maui, and work cooperatively with operators of existing energy storage on Maui as a means to facilitate increased renewable energy (that is, reduced curtailment) and reliable system operation.

6.F. Maui Electric will perform an engineering analysis to determine possible impacts of tsunami to the Maalaea Power Plant, and implement appropriate mitigation measures.

Fairness

As described in the Action Plan for Hawaiian Electric (see 7.A., 7.B., and 7.C. on page ES-32), Maui Electric will work collaboratively with Hawaiian Electric and Hawaii Electric Light to implement the actions uniformly across the Companies.

Maui Electric Action Plan (Molokai)

Lower Customer Bills

1. Replace Oil with LNG

1.A. To assure compliance with EPA's air regulations, the lowest-cost solution is to convert existing generation from burning sulfur-bearing fuels to LNG. The Companies would support the development of LNG infrastructure to transport LNG from Oahu to Maui County, and regasification and distribution systems on the island(s) of Maui County. Combustion equipment will be modified to fire natural gas.

2. Other Projects to Lower Customer Bills

2.A. Maui Electric continue to support the initiatives for attainment of the Energy Efficiency Portfolio Standards and will work cooperatively with its customers to implement on bill financing (OBF) for customer-sited renewable energy installations on Molokai.

2.B. Through competitive solicitations, Maui Electric will continue to source low-cost biofuels for Molokai.

Clean Energy Future

3. Meet or Exceed Renewable Portfolio Standards

3.A. Maui Electric will work collaboratively with the Molokai community to implement cost-effective utility-scale PV with energy storage and/or a biomass generator.

Modernize Grid — Molokai Island

4. Improve Grid Operations

4.A. Maui Electric will implement upgrades to its transmission and distribution system on Molokai for purposes of safety, reliability, environmental stewardship, and customer requests.

4.B. The existing grid will be transformed into a "smarter", more efficient, more reliable grid that integrates more renewable energy through the use of various technologies and capabilities and provide more information and options to customers with the overall goal of reducing costs and improving customer service. Central to achieving this goal will be the use of advance metering infrastructure (AMI) to enable real-time communications between the customers and the utility. The initial smart meter deployments will be functionally and/or geographically targeted, however, the Companies are committed to island-wide deployment of smart meters (with customer opt-out option) for Molokai by 2018.

4.C. The telecommunications infrastructure on Molokai will be upgraded to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, smart grid technologies, and customer programs.

4.D. Maui Electric will continue its efforts to create and implement an effective asset management program for its transmission and distribution infrastructure on Molokai.

4.E. The companies will evaluate and implement additional energy storage resources on Molokai, and work cooperatively with operators of existing energy storage on Molokai as a means to facilitate increased renewable energy (that is, reduced curtailment) and reliable system operation.

Fairness

As described in the Action Plan for Hawaiian Electric (see 7.A., 7.B., and 7.C. on page ES-32), Maui Electric will work collaboratively with Hawaiian Electric and Hawaii Electric Light to implement the actions uniformly across the Companies.

Maui Electric Action Plan (Lanai)

Lower Customer Bills

1. Replace Oil with LNG

1.A. To assure compliance with EPA's air regulations, the lowest-cost solution is to convert existing generation from burning sulfur-bearing fuels to LNG. The Companies would support the development of LNG infrastructure to transport LNG from Oahu to Maui County, and regasification and distribution systems on the island(s) of Maui County. Combustion equipment will be modified to fire natural gas.

2. Other Projects to Lower Customer Bills

2.A. Maui Electric continue to support the initiatives for attainment of the Energy Efficiency Portfolio Standards and will work cooperatively with its customers to implement on bill financing (OBF) for customer-sited renewable energy installations on Lanai.

2.B. Through competitive solicitations, Maui Electric will continue to source low-cost biofuels for Lanai.

Clean Energy Future

3. Meet or Exceed Renewable Portfolio Standards

3.A. Maui Electric will work collaboratively with the Lanai community to implement cost-effective utility-scale PV with energy storage and/or biomass generator.

Modernize Grid — Lanai Island

4. Improve Grid Operations

4.A. Maui Electric will implement upgrades to its transmission and distribution system on Lanai for purposes of safety, reliability, environmental stewardship, and customer requests.

4.B. The existing grid will be transformed into a "smarter", more efficient, more reliable grid that integrates more renewable energy through the use of various technologies and capabilities and provide more information and options to customers with the overall goal of reducing costs and improving customer service. Central to achieving this goal will be the use of advance metering infrastructure (AMI) to enable real-time communications between the customers and the utility. The initial smart meter deployments will be functionally and/or geographically targeted, however, the Companies are committed to island-wide deployment of smart meters (with customer opt-out option) for Lanai by 2018.

4.C. The telecommunications infrastructure on Lanai will be upgraded to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, smart grid technologies, and customer programs.

4.D. Maui Electric will continue its efforts to create and implement an effective asset management program for its transmission and distribution infrastructure on Lanai.

4.E. The companies will evaluate and implement additional energy storage resources on Lanai, and work cooperatively with operators of existing energy storage on Lanai, as a means to facilitate increased renewable energy (that is, reduced curtailment) and reliable system operation.

Fairness

As described in the Action Plan for Hawaiian Electric (see 7.A., 7.B., and 7.C. on page ES-32), Maui Electric will work collaboratively with Hawaiian Electric and Hawaii Electric Light to implement the actions uniformly across the Companies.

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II. FUNDAMENTALS OF THE IRP REPORT

Chapter 1: Introduction

The goal of integrated resource planning is to develop an *Action Plan* that governs how the Hawaiian Electric Companies will meet energy *objectives* and customer energy needs consistent with state energy policies and goals, while providing safe and reliable utility service at reasonable cost, through the development of *Resource Plans* and *Scenarios* of possible futures that provide a broader long-term perspective.

About Integrated Resource Planning

Integrated Resource Planning (IRP) is a planning, analysis, and decision-making process that examines and determines how a utility will meet future demands.

The concept of IRP was developed in the 1980s as a refinement of a least-cost planning process, and represents a fundamental change from "traditional" utility resource planning because the IRP process:

- Integrates efficiency and load management programs, considered on par with supply resources.
- Integrated broadly framed societal concerns, considered in addition to direct dollar costs to the utility and its customers.
- Integrated public participation into the utility planning process.

The analysis incumbent to every IRP focuses on developing an Action Plan rather than single preferred resource plan. The 2013 IRP process for the Companies employs scenarios planning, possible futures in which the utility might need to operate. Scenario planning enables the results of the IRP process to nimble and broad enough to be prepared for future contingencies.

The goal of the IRP is to develop an Action Plan that is valid and executable, while being flexible enough to meet the ever-changing future landscape in which utilities constantly operate. The IRP Action Plan identifies specific and necessary actions and options.

Fundamental Concepts of the IRP

The Commission defined some fundamental concepts that apply to the IRP 2013 process.

Goal of Integrated Resource Planning

The Public Utilities Commission has stated the following goal:

> The goal of integrated resource planning is to develop an Action Plan that governs how the Hawaiian Electric Companies will meet energy objectives and customer energy needs consistent with state energy policies and goals, while providing safe and reliable utility service at reasonable cost, through the development of Resource Plans and Scenarios of possible futures that provide a broader long-term perspective.[5]

As the goal states, the Companies must develop an Action Plan based on Resource Plans and Scenarios with Advisory Group input throughout the process.

The Framework also defines the following terms, as they are integral to our planning and analysis.

Action Plan

> "Action Plan" means an implementation plan and schedule for the specific actions, resource options, and programs to be executed by the utility to serve its customers' future energy needs and requirements in a manner consistent with the framework. The Action Plan covers the first five (5) years of the twenty (20) year horizon based on the Scenarios analyzed.[6]

Resource Plan

> "Resource Plan" means a set of resources, programs, or actions over the twenty (20) year planning horizon resulting from the analyses performed for the Scenarios developed during the integrated resource planning process governed by this framework.[7]

Scenarios

> "Scenarios" means a manageable range of possible future circumstances or set of possible circumstances reflecting potential energy-related policy choices, uncertain circumstances, and risks facing the utility and its customers, which

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5 A Framework for Integrated Resource Planning, Revised March 14, 2012, Section II. A: Goal of Integrated Resource Planning; page 2.

6 *ibid.*, Section I. Definitions; page 1.

7 *ibid.*, page 2.

will be the basis for the plans analyzed. A Scenario may not (*that is, cannot*) consist of a particular project.

Scenarios are plausible futures. They deal with 'what if' questions, and tell a story of uncertainties that need to be coped with. They contemplate things the Companies can't control, don't know, attempt to capture the range of possibilities, and focus on the joint effect of many factors. They are not predictions.

Resource Plans and Strategies

As required by the Commission's Order No. 30534, the Companies must consider whether the Resource Plans effectively ensure affordable electric rates, maintain service reliability, and accommodate expected increasing proportions of variable and/or intermittent renewable generation resources. As required by the Framework, the Companies have developed final Resource Plans based on review of the various analyses and resource plans shown in *Appendix O: Resource Plan Sheets*. The final Resource Plans are designated as the Preferred Resource Plan, Contingency Resource Plan, Parallel Resource Plan, and Secondary Resource Plan. These plans identify resources and describe generally what the 20-year plans would look like if the future were to unfold as described by the particular scenario. The Companies describe these four plans in two Scenarios: Blazing a Bold Frontier and Stuck in the Middle (the "Reference Case") which represent two divergent futures that could occur. The Action Plan supports implementation of strategies from all four of these plans and not only a single specific resource plan. Although the Action Plan is composed of elements from the four plans, the Companies would not be implementing all of them at the same time. The Action Plan is flexible to allow for decisions to be made as the future unfolds.

Role of the Companies

The Companies are responsible for developing Scenarios and Resource Plans that provide a long-term perspective that guide the development an Action Plan for the next five years, subject to Commission approval. Once approved, the Company will implement the Action Plan.

Over the five-year implementation cycle, the Company will periodically examine and evaluate its Action Plan. During this time, the Company will also work collaboratively with the Public Benefits Fee Administrator to design energy efficient, demand-side management programs.

During the IRP process, the Companies:

- Identified (with input from the Advisory Group) a list of issues and objectives.
- Developed and designed four Scenarios on which analysis was conducted and resource plans were created.
- Considered Advisory Group and public comments.
- Emphasized the importance of reasonable cost and affordable energy services in all of the issues that are addressed.
- Ensured the continued safety and reliability of the overall grid.
- Considered, addressed, and factored into the IRP's Action plan issues identified by the Commission.
- Complied with the IRP Framework.

Compliance with the Revised Framework

At every step in the process, the Companies have endeavored to comply with the Revised Framework. Specifically, we have:

- Developed resource plans and an Action Plan in consultation with the Advisory Group, the public, and the Independent Entity.
- Complied with applicable federal, state, and county laws, formally adopted state and county plans, and other applicable administrative and regulatory requirements.
- Considered and analyzed the short- and long-term costs, effectiveness, benefits, and risks of all appropriate, available, and feasible resource options and the adequacy and reliability of energy services.
- Considered the Action Plan's impact on the utility's customers, the environment, culture, community lifestyles, the State's economy, and society.
- Considered the utility's financial integrity, available sources of capital, ownership structure, size, and physical capability.
- Considered current governmentally established energy policies.
- Ensured an open and transparent public process that provided opportunities for public participation and feedback, and created a broad-based awareness of the complex and sometimes conflicting objectives and issues the utility and the Commission must resolve.
- Focused our planning analyses across a range of four Scenarios that guided the development of a reasonable and prudent Action Plan.
- Considered generation, transmission and distribution infrastructure requirements and associated capital and operating costs, including operational changes, grid upgrades, system capacity additions or replacements, and technological advances.

The Planning Process

In compliance with the IRP Framework, the Companies conducted the IRP process as summarized below:

Planning

During the planning step, the Companies:

- Identified the utility's needs.
- Identified the utility's objectives.

- Identified and clarified the assumptions, costs, risks, trends, expected events, and uncertainties.
- Developed the Scenarios to reflect possible futures dealing with uncertain circumstances and risks facing the utility and its customers.
- Identified the utility's system needs (such as generation, transmission and distribution needs).
- Determined the cost, effectiveness, and benefits of each resource option, program, or action under each Scenario.
- Explained the detailed analyses that were conducted.

Planning Period: This planning resulted in the utility's resource plans for the planning period of 2014–2033.

Programming (Analyzing and Evaluating)

During this step, the Companies analyzed and evaluated the resources, programs, and action from all of the resource plan for both the 20-year planning period and for the five-year implementation period of the Action Plan. During this process, the Companies determined the:

- Options selected to be implemented
- Order in which the selected options are to be implemented
- Phases or steps in which each option is to be implemented
- Expected target group and the annual size of the target group or annual target level of penetration of demand-side management programs
- Supply-side system additions and potential resource procurement method
- Relevant transmission system additions
- Estimated annual expenditures required to support implementation of the options.

This process resulted in a valid and executable Action Plan that includes a timeline for implementing the actions. See the entirety of Section IV: Executable Action Plans of this report for the plan details.

Submissions to the Commission

This 2013 Integrated Resource Planning Report contains a full and detailed description of the key phases of its integrated resource planning process, and describes:

- The planning objectives and principal issues that have been used and considered to provide guidance or be the basis for decisions made in the integrated resource planning process.
- The Scenarios developed that reflect possible futures dealing with uncertain circumstances and risks facing the utility and its customers,

which were used as the basis for the Resource Plans analyzed, and includes the rationale used to select and formulate the various Scenarios.

- The assumptions and their basis underlying the Scenarios and Resource Plans, and the key drivers of uncertainty that might significantly impact the assumptions.
- The risks, trends, expected events, and uncertainties associated with the Scenarios and Resource Plans.
- The forecasts made and the assumptions underlying the forecasts.
- The resource options or mix of resource options considered in the development of the Resource Plans for the Scenarios.
- The needs of the utility system (such as supply-side or transmission additions), and identifies the proposed procurement method.
- A detailed description of the analyses upon which the Resource Plans and Action Plan are based as well as the data, its source, and the methodologies used including, when possible, revenue requirement calculations, estimates of the potential impact of the plans on rates, bills and customer' energy use, external costs, risks and benefits, renewable portfolio standards and energy efficiency portfolio standards compliance, reliability impacts, and sensitivity analysis.

The Companies have included in this IRP a full and detailed Action Plan which, among other things, describes:

- An implementation schedule showing the resources, programs, actions, or phases of resources, programs, or actions to be implemented in each of the five years of the Action Plan.
- The estimated expenditures required to support implementation of each option or phase of such option.
- The steps anticipated in order to realize and implement the supply-side and demand-side resources.
- How the Action Plan was developed based on the resource plans and Scenarios analyzed.

This 2013 IRP Report is simply and clearly written and, when practicable, in non-technical language. The 2013 IRP Report contains numerous charts, tables, and other visual devices to aid in understanding the Scenarios, Resource Plans, the Action Plan, and our analyses, as well as a detailed table of contents. 2013 IRP Report begins with an Executive Summary of the Scenarios, Resource Plans, analyses, and Action Plan.

Complying with Planning Guidelines

The Companies have complied with the Planning Guidelines as outline in section V. Planning Guidelines of the IRP Framework. More specifically, the Companies have:

- Considered the input, comments, and suggestions provided by the Advisory Group and members of the general public, and incorporated this information to the extent feasible.
- Addresses issues and concerns identified by the Advisory Group, the Independent Entity, and the general public, to the extent feasible. (See *Appendix D: Advisory Group* and *Appendix G: Public Commentary*.)
- Identified planning objectives and metrics. (See *Chapter 3: Objectives and Metrics*.)
- Identified the principal issues. (See *Chapter 4: Principal Issues to Address*.)
- Characterized the existing systems and conditions. (See *Chapter 7: Resource Options*.)
- Determined a set of planning Scenarios and forecasts together with driving forces and major uncertainties that affect the Companies' planning. (See *Chapter 5: Scenario Planning, Chapter 6: Four Planning Scenarios, Appendix E: Quantifying the Scenarios* and *Appendix J: Scenario Planning Advisory Group Information*.)
- Identified appropriate, available, and feasible resource options while developing a reasonable range of Scenarios of possible futures. (See *Chapter 7: Resource Options and Appendix K: Supply-Side Resource Assessment*.)
- Performed detailed analysis to create a number of resource plans to analyze and use an input for creating detailed, executable Action Plans. (See the entirety of *Section III: Strategic Analysis of the Principal Issues*.)
- Developed four final Resource Plans designated as the Preferred Resource Plan, Contingency Resource Plan, Parallel Resource Plan, and Secondary Resource Plan. (See *Chapter 19: Action Plans*.)
- Created Action Plans for each utility that identify specific actions, costs, and implementation schedules based on our assessment of the resource plans. (See the entirety of *Section IV: Executable Action Plans*.)

Outline of the 2013 IRP Report

Here is a breakdown of the sections and chapters in the 2013 IRP report.

Table 1-1. 2013 IRP Report Chapter Summary Descriptions

#	Section	Summary Description
Section I	Executive Summary	Summarizes the Scenarios, resource plans, the analyses, and the Action Plan
Section II	Fundamentals of the IRP Report	Begins the seven chapters that describe the fundamental elements on which the report was based.
Chapter 1	Introduction	Introduces the concept of integrated resource planning, and describes how the Companies have complied with the Commission's order as stated in the Revised Framework
Chapter 2	Planning Process	Outlines the roles of the various participants in the IRP process, and describes the phases of the process.
Chapter 3	Objectives and Metrics	Describes the quantitative and qualitative metrics developed by the Companies with input from the Advisory Group used as a basis for analyses.
Chapter 4	Principal Issues to Address	Provides an outline of the 17 Principal Issues as identified by the Commission which framed the analyses conducted for the IRP process.
Chapter 5	Scenario Planning	Describes the three-day planning workshop with the Advisory Group in August 2012 which provided the basis for formulating the four planning Scenarios.
Chapter 6	Four Planning Scenarios	Describes in detail the four planning Scenarios, named to identify the nature of their potential future: Blazing a Bold Frontier; Stuck in the Middle; No Burning Desire; and Moved by Passion.
Chapter 7	Resource Options	Describes the existing resources for all five grids, the Demand Response (DR) programs, the Demand-Side Management (DSM) programs, and the supply-side resource options.
Section III	Strategic Analysis of the Principal Issues	Begins the 11 chapters in the details analysis section of the 2013 IRP Report, and explains where each Principal Issues was addressed in the Report.
Chapter 8	Resource Planning and Analysis	Comprises the bulk of the analyses conducted during the IRP process, including capacity planning criteria used, an overview of the modeling and analysis process, and detailed analyses of Demand Response, fossil fuel replacement, energy storage, energy efficiency, renewable portfolio standards, and fuel supply.
Chapter 9	Environmental Regulation Compliance	Explains and details analyses on how the Companies are planning to comply with the current environmental standards, and details compliance cost estimates.
Chapter 10	CIP CT-1 Generating Station Analysis	Describes our analysis about how best to use the Campbell Industrial Part CT-1 unit.
Chapter 11	Inter-Island and Inter-Utility Connection Analysis	Presents our analysis of connecting islands and grids to Oahu via an undersea cable.
Chapter 12	Smart Grid Implementation Analysis	Describes our analysis for implementing Smart Grid technologies and their related costs.
Chapter 13	Essential Grid Ancillary Services	Analyzes the costs and benefits for implementing new technologies that provide essential ancillary services.

#	Section	Summary Description
Chapter 14	Transmission Planning Analysis	Presents the analysis that evaluates the efficiency and effectiveness of our transmission and subtransmission systems, including load and cost forecasts for improvements and upgrades.
Chapter 15	Assessing the Capacity Value of Wind	Describes the analysis for assessing wind's capacity value toward meeting demand and system reliability.
Chapter 16	Integrating High Penetration of Variable Distributed Generation	Explains the challenges posed by integrating increasing amount of distributed generation into the grid, and discusses the fairness of its cost.
Chapter 17	Advisory Group Qualitative Metric Considerations	Lists two matrices of qualitative metrics accumulated by the Advisory Group that were included in our resource plans.
Chapter 18	Competitive Bidding and Resource Acquisition	Explains the competitive bidding process for acquiring resources.
Section IV	Executable Action Plans	Begins the section of four chapters that detail the Action Plans.
Chapter 19	Action Plans	Outlines the four strategic themes that form the basis of the Action Plans, explains how each Action Plan was developed, and discusses each utility's resource plans.
Chapter 20	Hawaiian Electric Action Plan	Details the specific actions, resource options, and programs to be implemented by Hawaiian Electric Company in the first five years of the planning period.
Chapter 21	HELCO Action Plan	Details the specific actions, resource options, and programs to be implemented by Hawaii Electric Light Company in the first five years of the planning period.
Chapter 22	MECO Action Plan	Details the specific actions, resource options, and programs to be implemented by Maui Electric Company in the first five years of the planning period.
Section V	Appendices	Begins the section of appendices that provide critical data used to create the 2013 IRP Report. See the Table of Contents for summary descriptions of these appendices.

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Chapter 2: Planning Process

The planning process employed to design, develop, analyze, evaluate, and create the 2013 IRP Report produced robust, Action Plans. The Companies designed and followed a six-phase process, and work collaboratively with several participants throughout the process.

Phases of the IRP Process

The Companies designed, and followed, a six phase process in analyzing, evaluating, and creating the 2013 IRP report.

1. Develop Scope

- State IRP goal
- Identify Principal Issues
- Characterize existing system and conditions
- Develop objectives and metrics

2. Identify Input

- Identify scenario driving forces
- Identify critical uncertainties
- Develop scenario framework and stories
- Develop initial planning assumptions

3. Quantify and Clarify

- Quantify the scenarios
- Finalize the planning assumptions
- Develop resource strategies

4. Test and Analyze

- Test the resource strategies
- Analyze the strategies
- Develop resource plans
- Compile results and metrics

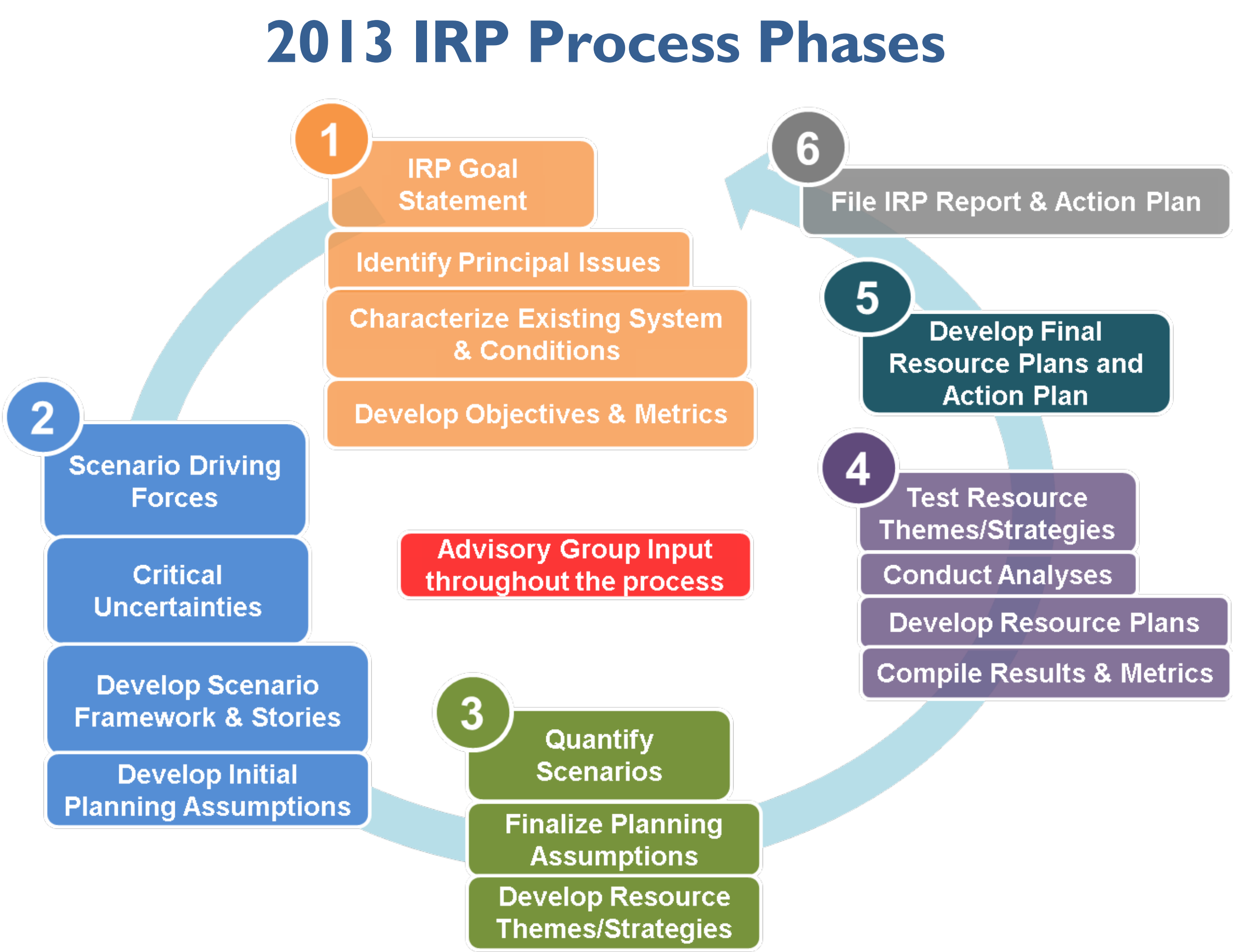
5. Develop the Final Resource Plans and Action Plan

- Define final Resource Plans
- Define flexible actions
- Provide value

6. File IRP Report and Action Plan

Process Phases Flowchart

Figure 1-1. 2013 IRP Process Phases



Participants in the IRP Process

As indicated in the IRP Framework, the following are participants in the IRP process:

- Commission
- Hawaiian Electric Companies
- Independent Entity
- Consumer Advocate
- Public Benefits Fee Administrator
- Advisory Group
- General Public

A brief, high-level outline of the roles for each of these participants follows.

Commission

The Commission's responsibility is to determine whether the Companies' Action Plan is in the public interest and represents a reasonable course for meeting the goal and objectives of the integrated resource planning process.

The Commission will review and evaluate the Companies' Scenarios, Resource Plans, Action Plan, and generally monitor the implementation the Action Plan as approved by the Commission.

The Commission will select the Independent Entity and Advisory Group members.

Hawaiian Electric Companies

The Hawaiian Electric Companies must prepare the IRP report and its incumbent Action Plan. The Companies must follow the process (outlined in *Chapter 1: Introduction*), perform the analyses, and file the IRP as specified in the IRP Framework. The Companies must consider the input of each Advisory Group member, but are not bound to follow that advice or recommendations.

After its approval, the Companies must implement the Action Plan and keep it current.

Independent Entity

The Independent Entity shall directly report to, take direction from, and be accountable to, the Commission or the Commission's designee. The Independent Entity's responsibilities include:

- Advising the Companies and the Commission.
- Providing unbiased oversight of the integrated resource planning process — including the development of Scenarios, Resource Plans, and the Action Plan — in a cost-effective and timely manner.
- Monitoring and evaluating the IRP process and reporting its status to the Commission.
- Chairing Advisory Group meetings and facilitating communication between the Advisory Group, the general public, and the Companies.
- Ensuring a timely process.
- Certifying the IRP process has been conducted consistent with the Revised Framework.

Advisory Group

The Advisory Group represented interests affected by IRP report. Members possess the ability to provide significant perspective and expertise to resource plan development. The Advisory Group's mission is to represent diverse community, environmental, social, political, and cultural interests and provide community perspectives through its participation in the IRP process.

Advisory Group members attend meetings; review utility planning activities; and provide questions, comments, and advice to the utilities. Advisory Group members were encouraged to arrive at consensus on issues to the extent possible or practicable, however they could also act as individuals.

Advisory Group Meetings

In total, the Advisory Group met 17 times for 20 days over the course of 11 months.

Ten Advisory Group meetings were held during key phases of the integrated resource planning process. In addition, seven working technical sessions were added to the process as events unfolded. Representatives from the Companies attended every meeting and technical session; provided Advisory Group members with reports, presentations, and other information; and presented and discussed valuable information about the planning process with Advisory Group members.

See *Appendix D: Advisory Group* for a list of these meetings and their agendas. Included in this appendix is the web address containing all the materials produced throughout these meetings. The appendix also contains utility responses to some Advisory Group comments and questions.

Consumer Advocate

The Consumer Advocate participated in the IRP process and be party to the IRP docket. The Consumer Advocate, as its title suggests, has a statutory responsibility to represent, protect, and advance the interests of the utilities' customers.

Public Benefits Fee Administrator (Hawaii Energy)

The Public Benefits Fee Administrator (who was a member of Hawaii Energy) participated in IRP process with the role of focusing on energy efficiency and Demand-Side Management programs including forecasts, studies of technical and economic potential, development of programs, and estimates of costs and effectiveness.

General Public

The general public was encouraged to provide advice and comments to the Companies through public forums. The Companies held eight public meetings during two time frames: late November/December 2012 and then again in June 2013 at times that would be most convenient for public attendance. Each time, individual meetings were Oahu, Maui, Lanai, and Molokai, with three meetings at separate locations on the Island of Hawaii.

Appendix G: Public Commentary describes the proceedings from these meetings.

Chapter 3: Objectives and Metrics

The goal of integrated resource planning is to develop an Action Plan that governs how each island utility will meet energy objectives and customer energy needs consistent with state energy policies and goals, while providing safe and reliable utility service at reasonable cost, through the development of Resource Plans and Scenarios of possible futures that provide a broader long-term perspective, that allow the Companies to plan with greater insight and forethought.

Introduction

2013 IRP Objectives

To better meet our goal of this IRP, the Companies have developed a number of objectives that the Companies will strive to attain. To summarize, these objectives are (not in any particular order):

1. Protect Hawaii's culture and communities.
2. Protect Hawaii's environment.
3. Reduce dependency on imported fossil fuels and improve price stability.
4. Increase the use of indigenous energy resources.
5. Provide reliable service.
6. Improve operating flexibility.
7. Provide electricity at a reasonable cost.

2013 IRP Metrics

Each objective comprises one or more metrics that enable the Companies to assess how well each objective is being met. Metrics are either qualitative or quantitative, depending on how they are measured.

Qualitative Metric. A *qualitative* metric measures the quality or characteristic of an objective. Qualitative metrics measure direction — for instance: up, down, or the same — rather than the size of the movement (which would be a hard number). While the description of a qualitative metric can be expanded beyond the simple "up, down, the same", this additional information is inherently subjective because they are based on personal opinion.

Quantitative Metric. On the other hand, a *quantitative* metric uses hard numbers to measure the movement of an objective. Quantitative metrics provide the actual number of a movement. Rather than indicating that sales went up, a quantitative measure would state the actual amount sales rose, such as "12% over the same time last year". While opinions might vary over what such a number means, the number itself — and thus all quantitative metrics — are objective. Thus, quantitative metrics have computable results.

2013 IRP Objectives and Metrics

Each of the seven 2103 IRP objectives cover a specific area that the Companies are striving to attain. In this chapter, each objective is explained together with the qualitative and quantitative metrics that the Companies are tracking.

I. Protect Hawaii's Culture and Communities

When moving toward a clean energy future, the Companies are mindful of the potential impacts to Hawaii's unique culture and varied community lifestyles.

Qualitative Metrics

Table 3-1. Qualitative Metrics: Protect Hawaii's Culture and Communities

Qualitative Metric	Comments
Potential impacts on, and compatibility with, community lifestyles	Opportunity for Advisory Group members to provide perspectives and comments, including any qualitative value surveys led and conducted by others.
Potential impact to Hawaii's culture and cultural values	Opportunity for Advisory Group members to provide perspectives and comments, including any qualitative value surveys led and conducted by others.

Quantitative Metrics

This objective is not measured with quantitative metrics.

2. Protect Hawaii's Environment

As the Companies move aggressively and decisively away from imported oil for electricity generation towards a diverse, local, and renewable energy future, Hawaii's environment will benefit from reduced emissions and lower greenhouse gases. However, the Companies' strategies and projects might have other impacts on the environment including, among others, land conversion, water resources, endangered species, and invasive species. Protection and preservation of Hawaii's unique environment must be taken into account in the development and implementation of projects.

Quantitative Metrics

Table 3-2. Quantitative Metrics: Protect Hawaii's Environment

Quantitative Metric	Units	Formula	Comments
Greenhouse Gas (GHG) emissions	Tons	Σ CO_2e Emissions	Representative measure of GHG emissions. Annual calculation of carbon dioxide equivalent (CO_2e) emissions based on fossil fuel consumption. Used to assess compliance with Hawaii's GHG emissions limit.
Sulfur oxides (SO_X) emissions intensity	Pounds/ MWh	$\frac{\Sigma\ SO_X\ \text{Emissions}}{\text{Net Sales}}$	Annual calculation of sulfur oxides (SO_X) emissions divided by unit of energy consumed.
Nitrous oxides (NO_X) emissions intensity	Pounds/ MWh	$\frac{\Sigma\ NO_X\ \text{Emissions}}{\text{Net Sales}}$	Annual calculation of nitrous oxides (NO_X) emissions divided by unit of energy consumed.
Particulate (PM) emissions intensity	Pounds/ MWh	$\frac{\Sigma\ \text{PM Emissions}}{\text{Net Sales}}$	Annual calculation of particulate (PM) emissions divided by unit of energy consumed. For Mercury and Air Toxic Standards (MATS), Filterable PM is an approved surrogate measure for Hazardous Air Pollutants metals. MATS only applies to large fossil-fuel fired steam electrical generating units.

Qualitative Metrics

Table 3-3. Qualitative Metrics: Protect Hawaii's Environment

Qualitative Metric	Comments
Impact on water resources	Assessment of potential impacts on water sources, both potable and marine.
Other potential non-air emissions related environmental impacts (for example, siting, land conversion, endangered species, invasive species)	Implementing projects may have significant environmental impacts other than emissions.

3. Reduce Dependency on Imported Fossil Fuels & Improve Long Term Price Stability

Providing secure, clean energy for Hawaii is a critical element of the Companies' mission. The Companies are playing a critical role in realizing the State's clean energy future by reducing our dependence on imported fossil fuel and other volatile-priced resources by effectively using Hawaii's diverse and abundant natural resources to generate energy. Importing millions of gallons of crude oil a year not only threatens our energy security, our economy, and our environment, but also subjects customers to high volatility in electricity prices because the cost of the majority of our generation is linked to the price of imported fossil fuel and other volatile priced resources.

Quantitative Metrics

Table 3-4. Quantitative Metrics: Reduce Dependency on Fossil Fuels

Quantitative Metric	Units	Formula	Comments
Share of delivered energy from imported fossil fuels	%	$\frac{\Sigma \text{(Energy Generated by Fossil Fuels)}}{\text{Net Generation, GWh}}$	Representative measure of the exposure of utility customers to volatile-priced resources. Calculated annually for generation from fossil fuels and generation that receive payments linked to fossil fuels (for example, oil and natural gas).
Share of the resource plan's cost linked to imported fossil fuels	%	$\frac{\text{Total Fuel Cost of Volatile Resources}}{\text{Total Resource Cost}}$	Indicative measure of the potential cost volatility of a resource plan due to the cost of fossil fuels in the plan. The accumulated present value of the fuel costs of the resource plan as a percentage of the total resource cost for the plan as a whole.
Amount of imported fossil fuel oils	Barrels	Σ Low Sulfur + Diesel Fuel Oil + Industrial Fuel Oil	Totaled annually for all energy generated by imported fossil fuel oils.
Amount of liquefied natural gas	(000) cubic feet	Σ Liquefied Natural Gas	Totaled annually for all energy generated by liquefied natural gas.
Energy efficiency portfolio standard savings	GWh	$\sum_{2014}^{2033} \textit{EEPS Energy Savings}$	Based on forecasts provided by EM&V Contractor/PBFA to lower the system demand and decrease fuel consumption.

Qualitative Metrics

This objective is not being measured with qualitative metrics.

4. Increase the Use of Indigenous Energy Resources

The Companies are committed to meeting and exceeding the Renewable Portfolio Standards (RPS) goals by actively seeking and incorporating a diverse portfolio of renewable energy resources to stabilize electricity prices and strengthen Hawaii's energy independence.

Quantitative Metrics

Table 3-5. Quantitative Metrics: Increase Use of Indigenous Energy Resources

Quantitative Metric	Units	Formula	Comments
Renewable Portfolio Standards percentage	%	$\frac{\Sigma \text{ (Qualifying Renewable Energy GWh)}}{\text{Net System Sales}}$	Calculated annually and for goal years of 2015, 2020, and 2030.
Renewable energy curtailed	GWh	Dumped Energy in GWh	Provided annually; identifies system constraints and measures opportunity to increase renewable energy by making changes to the system.
Resource diversity index	Ranges from 0 to 1 (one single resource to hypothetical perfect diversity)	$\alpha = 1 - \Sigma(x_i)^2$ where α is the resource diversity x is the generation share from a given resource across all generation types	Calculated annually. A diverse generation portfolio ensures that the company is not too dependent on one type of resource.
Share of generation from local resources	%	$\frac{\Sigma \text{ (Energy from Local Resources)}}{\text{Net Generation, GWh}}$	Calculated annually for generation from local resources (such as geothermal, wind, solar, biomass, biofuel, ocean, etc.) divided by total generation.

Qualitative Metrics

This objective is not being measured with qualitative metrics.

5. Provide Reliable Service

As regulated utilities, the Companies are responsible for providing safe, reliable power to their customers. The Companies must be able to meet the demand for electricity at any time with only reasonable disruptions in service. As the penetration of variable energy resources[8] increases, system operation becomes more challenging. Grid management measures to ensure reliable operations on each system will be essential to match demand with supply, especially if supply includes increasing amounts of variable energy resources.

Quantitative Metrics

Table 3-6. Quantitative Metrics: Provide Reliable Service

Quantitative Metric	Units	Formula	Comments
Reserve margin	%	$\frac{\text{System Net Capacity} - (\text{Peak} - \text{Interruptible Load})}{(\text{Peak} - \text{Interruptible Load})}$	Calculated annually.
Variable energy resource penetration	%	$\frac{\sum_{\text{As-Available}} (\text{Nameplate Capacity})}{\text{Average Peak Load}}$	Calculated annually. Proxy measurement of challenges with managing grid reliably as it illustrates the potential level of variable capacity that could be running at any time as a percent of the peak load.

Qualitative Metrics

Table 3-7. Qualitative Metrics: Provide Reliable Service

Qualitative Metric	Comments
System power quality	How do resources affect voltage stability? Can they add VARs? What are the ramping rates? Does it help system stability by adding to system inertia, etc.?
Geographic diversity of generating resources	Locational diversity of resources adds to the reliability and security of the system, however, the ability to site new resources is limited.

8 As defined in the Notice of Proposed Rulemaking, a Variable Energy Resource is a device for the production of electricity that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator. This includes, for example, wind, solar thermal and photovoltaic, and hydrokinetic generating facilities. *See Integration of Variable Energy Resources Notice of Proposed Rulemaking*, FERC Stats. & Regs. 32,664, at P 64 (2010) (Proposed Rule).

6. Improve Operating Flexibility

The Companies must continually improve the operating flexibility of each of their island systems to integrate renewable energy resources or new technologies of varying size and type. Having resources that provide necessary grid services provides operating flexibility to adapt to changes on the system.

Quantitative Metrics

Table 3-8. Quantitative Metrics: Improve Operating Flexibility

Quantitative Metric	Units	Formula	Comments
Generation efficiency	Heat Rate Btu/kWh	$\frac{\text{Fossil Fuel Energy Consumed}}{\text{Electrical Energy from Fossil Fuel}}$	Calculated annually. Efficiently use fuels, especially fossil fuels, for energy production.
System regulating capability	%	$\frac{\Sigma\text{ (Regulating Reserve + Demand Response + Quick Start)}}{\text{Peak Load}}$	Calculated annually. High level indicator of the capability of the system to manage the variability of the variable output from the as-available resources.

Qualitative Metric

Table 3-9. Qualitative Metric: Improve Operating Flexibility

Qualitative Metric	Comments
Appropriate mix of baseload, cycling, peaking generating capacity, and as-available generation	The mix of resources is important in providing the necessary grid services for integrating renewable energy.

7. Provide Electricity at a Reasonable Cost

As regulated utilities, the Companies are required to provide and distribute energy at a reasonable cost to their customers. Resource plans and action plans need to consider short-term and long-term costs to customers and the local economy while balancing these issues against energy policies, reliability criteria, environmental standards, and the Companies' financial integrity.

Quantitative Metrics

Table 3-10. Quantitative Metric: Provide Electricity at a Reasonable Cost

Quantitative Metric	Units	Formula	Comments
Nominal price of electricity (residential, commercial, and industrial rate classes)	Cents/kWh nominal	$\frac{\text{Revenue Requirements}}{\text{Net Sales}}$	Calculated annually. Proxy rate calculation of revenue requirements from model runs used for relative rate comparisons.
Nominal residential bill	$/month	(Nominal residential price of electricity) x (Typical residential monthly consumption)	Nominal monthly residential bill based on a typical monthly consumption.
Annual revenue requirements for capital	$ (000)	Utility Revenue Requirements for New Generation and Transmission Capital	Annual calculation. Serves as a proxy indicator of the utility's needs to raise investment capital from bondholders and shareholders.
Total Resource Cost (TRC)	$ (000) accumulated present value of revenue requirements	$\sum_{j=2014}^{2033}\left(\frac{TRC_j}{(1+r)^{j-2014}}\right)$	The accumulated total costs to the utility and its customers. The costs include fuel, non-utility generation payments, emissions, capital, O&M, and energy efficiency (both utility and customer).

Qualitative Metric

Table 3-11. Qualitative Metric: Provide Electricity at a Reasonable Cost

Qualitative Metric	Comments
Impact to the local economy	A reasonable rate influences the resources available to the local economy.

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Chapter 4:
Principal Issues to Address

On July 19, 2012, the Hawaii Public Utilities Commission (Commission) issued Order No. 30534 under Docket No. 2012-0036 that identified a number of issues for the Hawaiian Electric Companies to address when developing the 2013 IRP. The document provides an overview of the integrated resource planning process, then itemizes seventeen principal issues: five principal issues presented by the Hawaii Legislature with an additional twelve principal issues presented by the Commission. This chapter summarizes those seventeen principal issues which form the basis for the analysis performed to develop the 2013 IRP.

Introduction

The Public Utilities Commission (Commission) has issued four orders that directly affect the Hawaiian Electric Companies:

- Docket No. 2009-0108, *Decision and Order*, filed 14 March 2011, and Exhibit A: *A Framework for Integrated Resource Planning*. This order issued a revised Framework for Integrated Resource Planning (IRP) which states the goal of the Companies' IRP process. The revised IRP Framework includes scenario planning as a new tool for the Companies' development of its Action Plan.
- Docket No. 2012-0036, Order No. 30233: *Initiating HECO Companies' Integrated Resource Planning Process*, filed 01 March 2012. This order formally commenced the IRP process for the Companies.
- Docket No. 2012-0036, Order No. 30513: *Establishing the Advisory Group for the HECO Companies' Integrated Resource Planning Process*, filed 29 June 2012. This order established a 68-person Advisory Group, its members and their affiliations, and detailed its responsibilities in providing community perspectives to the Companies.
- Docket No. 2012-0036, Order No. 30534: *Identifying Issues and Questions for the Hawaiian Electric Companies' Integrated Resource Planning Process*, filed 19 July 2012. This order identifies several issues, questions, and objectives the Companies must address in the Integrated Resource Planning cycle, and include in their IRP report and Action Plan.

Per Section V.B.1. of the IRP Framework, the Companies have identified 17 principal issues that will be addressed in the IRP process. In order to better understand this task, the Companies identify our stated goal and governing principles under which the IRP must be conducted, then number, list, and describe each principal issue.

See *Appendix C: PUC Decision and Orders* for links to these documents.

Legislative Issues to Address

House Concurrent Resolution No. 58, H.D. 1, S.D. 1 (H.C.R. 58) presented two issues surrounding Renewable Portfolio Standards (RPS) and Energy Efficiency Portfolio Standards (EEPS).

The Resolution also directed the Commission to consider five issues in the IRP process for electric utilities.

Renewable Portfolio Standards (RPS)

The current law, Hawaii Revised Statutes §269-92, requires that the Companies meet the following renewable portfolio standard[9] (RPS) of:

1. Ten per cent (10%) of its net electricity sales by December 31, 2010.
2. Fifteen per cent (15%) of its net electricity sales by December 31, 2015.
3. Twenty-five per cent (25%) of its net electricity sales by December 31, 2020.
4. Forty per cent (40%) of its net electricity sales by December 31, 2030.

The Public Utilities Commission can establish standards for each utility that prescribe what portion of the RPS shall be met by specific types of renewable energy resources; provided that:

- Prior to January 1, 2015, at least fifty per cent (50%) of the RPS shall be met by electrical energy generated using renewable energy as the source, and after December 31, 2014, the entire RPS shall be met by electrical generation from renewable energy sources;
- Beginning January 1, 2015, electrical energy savings shall not count toward meeting the RPS;
- Where electrical energy is generated or displaced by a combination of renewable and nonrenewable means, the proportion attributable to the renewable means shall be credited as renewable energy; and
- Where fossil and renewable fuels are co-fired in the same generating unit, the unit shall be considered to generate renewable electricity in direct proportion to the percentage of the total heat input value represented by the heat input value of the renewable fuels.

[9] *Hawaii Revised Statutes* §269-91 [Definitions], "Renewable portfolio standard" means the percentage of electrical energy sales that is represented by renewable electrical energy.

Energy Efficiency Portfolio Standards (EEPS)

The current law, Hawaii Revised Statutes §269-96, established the EEPS to achieve four thousand three hundred (4,300) gigawatt hours of electricity-use reductions statewide by 2030 provided that the Public Utilities Commission establishes interim goals for electricity-use reduction to be achieved by 2015, 2020, and 2025.

Beginning in 2015, electric energy savings brought about by the use of renewable displacement or offset technologies (including solar water heating and sea-water air-conditioning district cooling systems) counts toward meeting this standard.[10]

1. Replace Existing Fossil Fuel Generating Plants

Consider strategies for replacing existing fossil fuel plants with renewable energy resources.[11]

2. Inter-Island Connectivity

Consider transmitting firm or intermittent electricity between islands, including developing undersea electricity transmission cables.[12]

3. Geothermal Resources

Consider generating electricity using geothermal steam on geothermal resources that replaces or mitigates fossil fuel-based generation.[13]

4. Energy Storage

Consider hydrogen and other available energy storage technologies to stabilize the grid when necessary.[14]

5. Waste-to-Energy Facilities

Consider generating electricity from waste-to-energy facilities to serve as an untapped fuel source.[15]

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[10] *ibid.*

[11] *Identifying Issues and Questions for the Hawaiian Electric Companies' Integrated Resource Planning Process*, Section I. Background; item 1; page 3.

[12] *ibid.*, item 2.

[13] *ibid.*, item 3.

[14] *ibid.*, item 4.

[15] *ibid.*, item 5.

Commission Issues to Address

The Commission has identified a number of issues, in both its current dockets as well as in past dockets, that the Companies must address.

6. Best Use of Hawaiian Electric CIP CT-1 Generating Facility

The IRP must ascertain whether the current exclusive use of biofuel in CIP CT-1 reflects the highest or best use of the unit. For example, can greater efficiencies, and/or overall system benefits be gained if CIP CT-1 is used to support the maximum integration of renewables through the use of more efficient and/or cheaper fuels, rather than limiting CIP CT-1 use as a biofuel peaking unit with a negligible contribution to the Renewable Portfolio Standard?[16]

7. Reasonable Cost and Rate Impacts

The Companies, with input from the Advisory Group, must consider whether the IRP report and Action Plan result in affordable electric utility service. Reasonable cost is an important objective for resource planning identified in the statement of the goal of Integrated Resource Planning. The affordability of utility-provided energy services is a primary concern and objective of the Commission, especially in light of the need for timely implementation of statutory standards and goals and the need to maintain reliable energy service. Among any other possible measures of the achievement of this objective, the Companies' planning analysis shall include meaningful measures of the rate impacts of the Resource Plans and Action Plan evaluated in accordance with the planning scenarios, forecasts, and sensitivity analyses. The Companies shall determine meaningful methods to measure rate impacts with input from the Advisory Group.[17]

8. RPS Rate Impact

The Companies shall consider in its analysis the cost and rate impacts that result from fully attaining, various levels of partially attaining, as well as exceeding the current RPS law.[18]

[16] *ibid.*

[17] *ibid.*, Section II. Issues, Questions, and Objective, A. Reasonable Cost and Rate Impacts; page 6.

[18] *ibid.*, Item 1; page 7.

9. EEPS Rate Impact

The Companies shall consider in its analysis the cost and rate impacts that result from fully attaining, various levels of partially attaining, as well as exceeding the current EEPS law.[19]

10. Captive Customer Rate Impact

The Companies must consider whether and to what extent utility customers who do not have a renewable energy device or have implemented energy efficiency measures could face high cost and rate impacts if utility sales decrease for any of several possible causes. The planning process should consider circumstances that could compound to result in high utility fixed costs and/or low utility system sales and evaluate the extent to which these circumstances could lead to high rate impacts and possible customer exit or self-generation.[20]

11. Inter-Island and Inter-Utility System Transmission

The Companies must analyze the comparative costs and benefits of whether possible alternate inter-island and inter-utility system transmission connections across multiple islands can be used to increase use of renewable energy resources, lower costs of existing fossil-fuel resources, or provide other net benefits across multiple islands.[21]

12. Smart Grid Implementation

The Companies must analyze the comparative costs and benefits of whether adoption and utilization of a smart grid, including smart meters, should be completed by the Companies. The Companies shall analyze how these technologies could:

- Enable the electrical grid to be operated more efficiently and reliably.
- Enhance customer service.
- Accommodate additional renewable energy resources through energy storage and by remotely controlling customers' loads, that is, Demand Response (DR).
- Increase energy efficiency and conservation through real-time transparency of energy usage and costs.

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[19] *ibid.*, Item 2; page 7.

[20] *ibid.*, Item 3; pages 7–8.

[21] *ibid.*, Item 1; page 8.

- Modify the existing and future distribution system design criteria and operation practices to enable greater interconnection of distributed renewable energy resources.[22]

13. Environmental Regulation Compliance

The Companies must analyze the comparative costs and benefits of strategies to comply with expected and possible changes in environmental regulations. One of the strategies to be analyzed is whether fuel switching will result in the net reduction in capital and operating costs when complying with new environmental regulations.[23]

14. Fuel Supply and Infrastructure

The Companies must analyze the comparative costs and benefits of:

- Modifying the fuel supply portfolio and delivery infrastructure—for existing utility and non-utility fossil generation resources—to reduce system fuel costs and/or reduce environmental compliance costs.
- Assessing the total cost (capital, fuel, and operating expenses) and merits of fuel supply strategies to utilize alternate fuels, supply procurement methods, and delivery options.

One specific question concerns the fuel supply infrastructure requirements, including costs, necessary to provide diverse fuel sourcing, procurement, and delivery options. Will significant changes in fuel output by refineries operating in Hawaii affect the Companies' fuel supply options?[24]

15. Fossil Fuel Generation Resources

The Companies must analyze the comparative costs and benefits of:

- Modernizing or adapting existing utility and non-utility fossil generation resources to achieve greater efficiency, reliability, and flexibility to reduce renewable energy curtailment.
- Assessing the costs and merits of retiring units (with or without replacement), minimizing the amount of must-run fossil generation, and enhancing the operational flexibility of generating units to reduce costs and increase renewable energy penetration.[25]

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[22] *ibid.*, Item 2; pages 8–9.
[23] *ibid.*, Item 3; page 9.
[24] *ibid.*, Item 4; page 9.
[25] *ibid.*, Item 5; page 10.

16. Essential Grid Ancillary Services

The Companies must analyze the comparative costs and benefits of:

- Implementing new technologies, measures, and strategies to decrease reliance on fossil-fuel generation resources, provide essential grid ancillary services, and accommodate expected increasing proportions of variable and/or intermittent renewable generation resources.
- Assessing the costs and merits of possible non-fossil fuel resources, technologies, or programs to provide quick-response capacity and other ancillary services—including modifying existing fossil and renewable energy generating units, customer demand response programs, and energy storage resources.[26]

17. Transmission Planning Analysis

The Companies must analyze the comparative costs and benefits of adding to or modifying existing transmission and subtransmission systems to:

- Meet system and/or local load growth.
- Comply with reliability planning criteria.
- Interconnect new generation resources regardless of ownership or technology.
- Retire, with replacement, aging and antiquated grid infrastructure.
- Mitigate transmission congestion (bottlenecks).

The result of these analyses is to provide the long-term transmission capital investment requirements for the Companies.[27]

One specific question is to what extent fossil generation must operate due to lack of sufficient transmission capacity or other grid operational constraints (such as local voltage support) while solar or wind resources are being curtailed?

[26] *ibid.*, Item 6; pages 10–11.

[27] *ibid.*, Item 7; page 11.

Action Plan Validation and Execution

The Companies shall determine and demonstrate that their Action Plan represents a reasonable course of action. The Action Plan must:

- Comply with the Revised IRP Framework.
- Provide "the greatest value and flexibility across as many of the evaluated Scenarios and Resource Plans as reasonably practicable".
- Represent a reasonable course of action.
- Be dynamic, and not fixed and unchanging. In particular, the Action Plan must be:

> "Flexible enough to account for changes in planning assumptions, forecasts, and circumstances. This will allow for major decisions regarding the implementation of options (both supply-side and demand-side resources) to be made incrementally, based on the best and current available information at the time decisions are made."[28]

[28] *ibid.* at 14, C. Action Plan Validation and Execution; pages 11–12.

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Chapter 5: Scenario Planning

A scenario planning workshop was held during the week of August 20–24, 2012. The schedule included a two-day workshop during which the Advisory Group drafted several scenarios, and final day during which the Companies presented four Scenarios which were an assimilation of the Advisory Group's input.

Overview of Scenario Planning

During the week of August 20–24, 2012, the Companies, with input from the Advisory Group, were able to develop the four Scenarios that formed the basis of the IRP analysis. During the workshop, the Advisory Group created over 20 draft scenarios, from which the Companies developed the final four scenarios. The workshop was facilitated by a representative from the Global Business Network, a scenario and strategy consulting firm.

The planning schedule consisted of a two-day workshop with the Advisory Group on August 20–21, two days assimilating the information garnered from the workshop by the Companies, and a final summary day on August 24 with the Advisory Group.

The purpose of the workshop was to present the Advisory Group with a process of creating and reviewing driving forces in the electric utility industry, and to fashion potential futures that could result from these driving forces. The Companies worked closely with the Advisory Group to prepare them for the workshop, and to facilitate their work in designing and creating the scenarios. The role of the Company was to oversee and facilitate the process, but not to be involved in the actual creation of the Scenarios.

At its essence, the workshop proceeded along a pre-determined outline. The Advisory Group was broken out into five separate groups. Each group brainstormed among themselves, and created their own set of plausible scenarios. After this two-day workshop concluded, the Companies together with their consultants, spend two days assimilating the five work group scenarios, to create four planning Scenarios that incorporated the most common elements. On the last day of the week, the Companies presented these assimilated Scenarios to the Advisory Group and solicited their comments and suggestions.

Preparing for the Workshop

To help the Advisory Group members prepared, the Companies wrote a Pre-Read Packet that was provided to the Advisory Group one week before the start of the workshop. The Pre-Read Packet contained the following elements:

- **Welcome and Overview (Cover Letter).** This cover letter described the reason for creating Scenarios, a definition of Scenarios, an overview of the entire Pre-Read packet, and the workshop schedule for the week.
- **Ten Tips for Successful Scenarios.** A list of ten tips (written by the cofounders of Global Business Network) together with descriptions that would enable the Advisory Group to better understand the process of creating Scenarios, and how to work within that process.
- **Scenario Thinking Defined.** A chapter from the book *What If? The Art of Scenario Thinking for Nonprofits* written by Global Business Network staff.
- **Pre-Read Packet.** A compendium of information necessary to develop scenarios. This packet describes and provided extensive examples of driving forces, which establish a foundation for creating scenarios. The packet also included instructions for preparing for the workshop together with extensive utility reference material, including graphs of fuel forecasts, of peak and sales forecasts, and for energy efficiency, as well as a basic glossary of industry terms.

The Pre-Read Packet is reproduced in *Appendix J: Scenario Planning Advisory Group Information*.

Scenario Workshop

The workshop followed this agenda for the two working main workshop days on Monday and Tuesday, August 20–21.

Monday Morning, August 20

- Welcome and introductions.
- Brief overview of scenario planning (Hawaiian Electric).
- Discussions about Hawaiian Electric driving forces (small groups).
- Overview of critical uncertainties (Hawaiian Electric).
- Labeling of critical uncertainties (small groups).
- Four to six well-labeled critical uncertainties (from each small group).

Monday Afternoon, August 20

- Plenary discussion of work on critical uncertainties.
- Further refinement of labeled critical uncertainties (small groups).
- Introduction to scenario frameworks (Hawaiian Electric).
- Creation of scenario frameworks (small groups).
- Plenary discussion of work on scenario frameworks.
- Selection of one scenario framework (small groups).
- Finalization of one scenario framework and the naming of four scenarios (small groups).
- Summation and instructions for tomorrow.

Tuesday Morning, August 21

- Plenary reflections on creating scenarios.
- Preparation of high-level scenario stories (small groups).
- Plenary presentation of some proposed scenario sets.
- Straw poll to assess strongest scenario frameworks most relevant to the IRP.
- Plenary discussion about the straw poll results.
- Create teams to work on ‘favorite’ scenario frameworks.

Tuesday Afternoon, August 21

- Establishment of broad targets (Hawaiian Electric).
- Development of scenario narratives relevant to the IRP.
- Identification of high-level implications for each scenario.
- Final plenary read-out of scenarios, stories, and emerging implications.
- Plenary discussion and group voting for final selection of preferred scenario framework.
- Selection of final scenario framework.

Opening Presentation

An opening presentation established the basis for the scenario planning workshop by:

- Defining scenarios and their role in integrated resource planning.
- Presenting a seven step process for creating scenarios.
- Discussing the concept of driving forces and how to identify them.
- Discussing the concept of critical uncertainties and providing examples.
- Outlining how to use the driving forces and critical uncertainties to create a matrix of a scenario framework.
- Explaining how to identify draft scenarios and write their stories.
- Explaining how to identify how the scenarios effect resource planning for the Companies.

The Advisory Group was separated into five working groups where they created a list of driving forces, choose the essential drivers, and determined critical uncertainties from which they formulated at least four draft scenarios. Each Advisory Group team then presented their scenarios and discussed the "stories" behind them: the plausible future scenarios.

Company representatives did not participate in the workshop; instead they facilitated Advisory Group members during the workshop.

Wednesday and Thursday, June 22–23

During these two days, the IRP planning team and its consultants, assimilated the information created by the five Advisory Group groups. The team compared and contrasted all of the draft scenarios, refined the gathered information, and used that as a basis to group common themes into four final draft scenarios.

Friday, June 24

On the last day of the week-long workshop, the Companies presented these four resultant scenarios to the Advisory Group, where attendees had the opportunity to comment and further refine the scenarios.

Advisory Group Workshop Outputs

As a result of the Advisory Group's work during the workshop, the Companies were able to assimilate and refine the four Scenarios that were subsequently used throughout the IRP process. Those Scenarios are described in detail in *Chapter 6: Four Planning Scenarios*.

As the next Advisory Group meeting, the Companies presented a summary of the scenario development workshop. This document contained five major sections:

1. Driving Forces influencing the future evolution of the energy landscape in Hawaii between the present and 2032.
2. Major Uncertainties influencing future scenarios.
3. Critical Uncertainties which could substantially impact the future modeling assumptions.
4. The Initial Scenario Set encompassing the five individual team scenario frameworks and a final scenario set integrated from across all five frameworks.
5. Feedback from the Advisory Group on the initial scenarios.

This document is reproduced in *Appendix J: Scenario Planning Advisory Group Information*.

From the workshop, the Companies were also able to refine the objectives and metrics (see *Chapter 3: Objectives and Metrics*) used as measurements for analysis conducted during the IRP process.

Chapter 6:
Four Planning Scenarios

During the scenario planning workshop in August 2012, the Advisory Group developed the foundation for creating scenarios based on key uncertainties and major driving forces. From that foundation, the Companies developed four scenarios that described potential futures to be used in resource planning. The final four scenarios describe different futures that can help the companies better meet the demands of the ever-changing future environment.

These four scenarios are titled:

- Blazing a Bold Frontier
- Stuck in the Middle
- No Burning Desire
- Moved by Passion

Key Uncertainties

Key Uncertainties are a select subset of the entire universe of driving forces provided by the Advisory Group during the scenario development workshop. These key uncertainties affect the wide range of possible futures that the Companies need to address when developing their IRP Action Plan. The key uncertainties share two characteristics. They are:

- Exceptionally powerful factors or trends that can *substantially alter* the core assumptions that modelers and planners make about the future.
- Exceptionally volatile factors or trends that cannot be easily predicted by traditional forecasting methods.

In creating scenarios, key uncertainties are important elements precisely because they matter and often defy the best efforts of forecasters. The scenarios incorporated intentionally broad yet plausible combinations of these factors. The planners are then able to think expansively beyond traditional IRP assumptions, without having to model an infinite number of permutations on those assumptions.

These key uncertainties strongly influence the future conditions under which the utility might need to operate. This is distinguished from the future plans that the utility might make in response to a particular scenario. The scenarios are simply imaginative, plausible futures that are not predisposed towards any particular strategy that the utility might ultimately exercise. Under this context, and considering the input of the Advisory Group, the Companies have identified the following key uncertainties.

1. Community Sentiment
2. Economic Conditions
3. Renewable Energy Regulations
4. Fuel Supply and Prices (oil, biofuels, and natural gas)
5. Electricity Demand (self-generation and energy efficiency impact)
6. Energy Incentives
7. Environmental Regulations (Greenhouse Gas Regulations such as CO_2 tax)
8. Operating Cost (includes maintenance)
9. Construction Cost Escalation Rate (includes renewable technologies)

Four Energy Scenarios

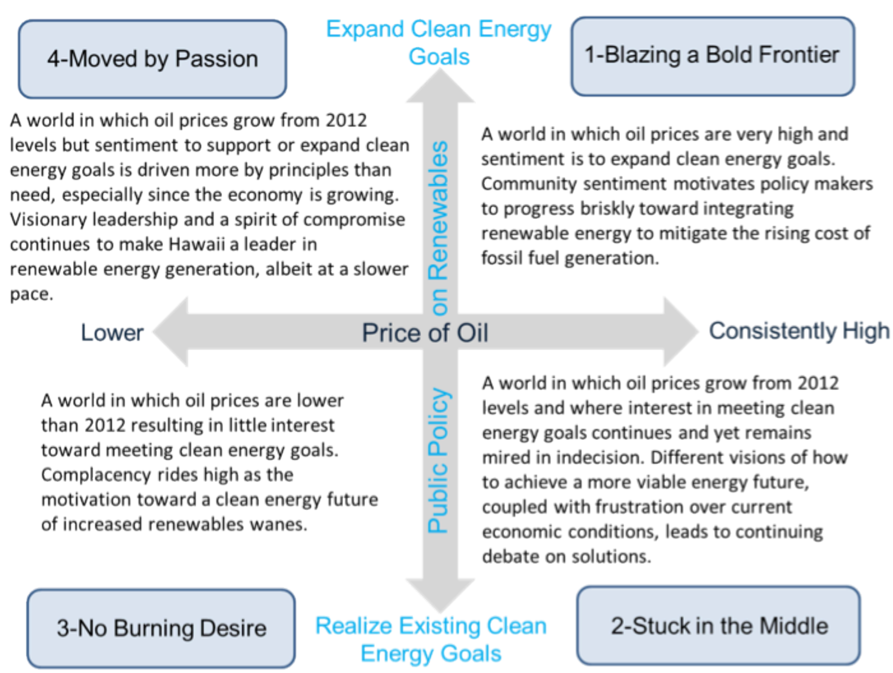
The Companies used these key uncertainties to develop four scenario descriptions each of which focused on the sets of divergent modeling assumptions to be utilized in analyzing the resource strategies.

These four scenarios describe future conditions under which the Companies could potentially operate and outline credible circumstances that pertain to the energy and utilities industries:

- Blazing a Bold Frontier
- Stuck in the Middle
- No Burning Desire
- Moved by Passion

Each scenario describes potential circumstances for each key uncertainty. These scenarios can also be depicted in a matrix comparing the price of oil and public policy on renewables.

Figure 6-1. Scenario Matrix



I. Blazing a Bold Frontier

A world in which oil prices are very high and sentiment is to expand clean energy goals. Community sentiment motivates policy makers to progress briskly and boldly toward integrating renewable energy to mitigate the rising and high cost of fossil fuel generation on electricity rates.

Community Sentiment

Sustained, productive community engagement and desire to preserve Hawaii's unique environment results in energy innovation, resourcefulness, and creativity. Wide-spread community support exists for Hawaii to eliminate its oil dependency to better ensure energy security.

Economic Conditions

Overall, the economy grows slowly.

Honolulu County experiences a deep and prolonged downturn in the near term with job losses continuing through the next decade. Over the full 20-year integrated resource planning period, population remains stable with a small decline in the job base (compared with a 0.7% average job growth in the baseline). Real income expands at only 0.2% annually over these two decades.[29]

Hawaii County experiences a short-term downturn, followed by an anemic recovery. Over the two-decade planning period, population together with the job base grow slightly (compared with 1.5% average annual job growth in the baseline). Real income expands at only a 0.9% annual rate over these two decades.[30]

In the near term, Maui County experiences a very sluggish job and income recovery. Over the entire two-decade planning period, both the population and the job base experience only slight growth (compared to a 1.2% average annual job growth in the baseline). Real income expands at only a 0.6% annual rate over these two decades.[31]

Renewable Energy Regulations

Inspired action by law makers and government leaders causes the renewable portfolio standards (RPS) to be increased beyond current legislative directives.

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[29] Based on *UHERO Long-Term Projections and Scenarios* prepared for Hawaiian Electric Company, Inc. (HECO), May 16, 2012.

[30] Based on *UHERO Long-Term Projections and Scenarios* prepared for Hawaii Electric Light Company, Inc. (HELCO), May 16, 2012.

[31] Based on *UHERO Long-Term Projections and Scenarios* prepared for Maui Electric Company, Ltd. (MECO), May 16, 2012.

Fuel Supply and Prices (oil, biofuels, and natural gas)

Fuel oil prices for Hawaii are even higher than anticipated 2012 levels due to increased demand in Asia for low sulfur fuels. This is driven by Japan in particular as the country continues to recover from the earthquake that shuttered its nuclear generation in 2011. Changes in the output from local refineries could also drive high fuel prices, adversely affect fuel supply options, and ultimately lead to higher fuel prices.

Skyrocketing oil prices force intense inspection of renewable alternatives. Hawaii begins to see lower biofuels prices due to technological breakthroughs, increased local production of biofuels and their associated feedstock, and increased worldwide supply of biofuels.

Natural gas production in North America quickly ramps up as predicted as America looks to become more energy self-sufficient and many new LNG export terminals are permitted and constructed. Hawaii, however, is not able to secure LNG pricing tied to Henry Hub gas prices, and can only obtain gas priced against oil alternatives such as the Japan Crude Cocktail price.

Electricity Demand (self-generation and energy efficiency impact)

The call for solutions to high energy prices leads policy makers to increase the energy efficiency portfolio standards (EEPS) beyond current legislative directives. High electricity prices motivate more customers to migrate off grid and self-generate all or part of their needs especially with the advent of energy storage batteries for the residential market.

All of these factors lead to falling electricity demand, resulting in upward pressure on pricing. Petroleum based transportation is very expensive and many alternatives become commonplace including the use of biodiesel for commercial vehicles and electric cars. Electric vehicle (EV) penetration exceeds expectations as new players enter the market and the consumers have many attractive EV choices.

Energy Incentives

Progressive discussions by policy makers, energy entrepreneurs, and motivated citizens trigger a remarkable series of breakthrough events that allow for lower energy prices. Existing tax incentives are continued and many new incentives are introduced to encourage increasing the use of renewables, electric vehicles, and energy efficiency measures. Customers are pleased to have a wide array of energy alternatives, even though prices vary just as widely.

Environmental Regulations

To help spur a transition to greater and faster use of renewable sourced generation, greenhouse gas legislation is passed which adopts a very stringent carbon tax policy (CO_2 tax).

Operating Cost (includes maintenance)

This rapid change for energy alternatives engenders many challenges, including increased utility operating expenses.

Construction Cost Escalation Rate (includes emerging technologies)

An entire raft of renewable, alternative, newer, and cleaner energy technologies emerge. In light of high fuel oil prices, many new players create competitive alternatives while offering new service options.

2. Stuck in the Middle

A world in which oil prices grow from 2012 levels and where interest in meeting clean energy goals continues and yet remains mired in indecision. Different visions of how to achieve a more viable energy future, coupled with frustration over current economic conditions, lead to continuing debate on solutions and little policy changes.

Community Sentiment

Sentiment toward the Companies has dipped to new lows as customers are frustrated with high electricity prices. While communities embrace a passion for a more sustainable energy mix, their visions for that future are conflicting and contradictory. Ardent activism is prevalent, but generally unfocused without garnering full political support and thus cannot be sustained. Most residents agree that the current situation is untenable, yet cannot concur on a clear path. Supporters of renewable energy projects are pitted against communities seeking to avoid impact to Hawaii's unique environment. Progress requires grim trade-offs that strain communities, discouraging bold initiatives and courageous action because of perceived risks and fairness issues.

Economic Conditions

Overall, the economy experiences moderate growth over the next ten years. Over the long term, Hawaii is expected to experience a dampening of economic growth rates as a result of slower growth in Hawaii's major visitor markets; constraints to visitor capacity expansion; and a deceleration of population growth in all counties.

All of these trends contribute to slow economic growth beyond the current decade. The economy continues a gradual process of natural diversification: the tourism mix evolves toward emerging markets while non-tourism areas grow as a share of local economic activity.[32]

Oahu, Hawaii, Maui, Molokai, and Lanai continue to experience a gradual increase in economic diversification similar to that seen in recent years. While tourism remains a key component in the local economy, it becomes somewhat less dominant as an employer than it has been historically. Other industries (such as health care and business services) increase. Agriculture and manufacturing—already small sectors—shrink further in relative importance over the next two decades.[33]

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[32] Based on *UHERO County Forecast: Sponsors Edition: Jobs Still Lag in County Recoveries*, May 18, 2012.

[33] Based on *UHERO Long-Term Projections and Scenarios* prepared for Hawaiian Electric Company, Inc. (HECO), May 16, 2012; *UHERO Long-Term Projections and Scenarios* prepared for Hawaii Electric Light Company, Inc. (HELCO), May 16, 2012, and *UHERO Long-Term Projections and Scenarios* prepared for Maui Electric Company, Ltd. (MECO), May 16, 2012.

Renewable Energy Regulations

The continuing clean energy debate leads to no changes with the existing renewable portfolio standards (RPS). There still is an underlying pressure by some to change the Companies' energy mix yet progress toward that change does not have the political support to move forward.

Fuel Supply and Prices (oil, biofuels, and natural gas)

Hawaii continues to see high fuel oil prices from 2012 levels due to continued competition especially by Japan and the maritime transportation sector for the same sulfur content fuels. Biofuel prices continue to be high due to the absence of any technology breakthroughs and the high cost of local production. Natural gas production in North America ramps up as predicted and many new LNG export terminals are permitted and constructed.

Electricity Demand (self-generation and energy efficiency impact)

Despite a concerted effort by the Public Benefit Fee Administrator and government agencies to implement new energy efficiency building codes, the actual amount of energy savings falls short of the energy efficiency portfolio standards (EEPS) set by the current law. Migration to self-generation (to fulfill all or part of energy needs) continues albeit at a slower pace and primarily for those who can afford it on their own. This results in a slightly decreasing energy demand in the future. Electric vehicle (EV) penetration growth is dampened by continued consumer preference for gasoline and hybrid vehicles.

Energy Incentives

With moderate economic growth, policy makers support the need to move to a clean energy future, but growing competition for limited government funds ultimately leads to a phase out or sunsetting of alternative energy tax credits.

Environmental Regulations

The moderate economy creates a political environment with little support to establish greenhouse gas laws in the form of a carbon tax.

Operating Cost (includes maintenance)

Costs continue to escalate at expected escalation rates.

Construction Cost Escalation Rate (includes emerging technologies)

Investment dollars are available, but decisions either can't be made regarding renewable projects, or are slowed by interminable and contentious public debate over size, siting, and transmission issues.

3. No Burning Desire

A world in which oil prices are lower than 2012 resulting in little interest toward meeting clean energy goals. Complacency rides high as the motivation toward a clean energy future of increased renewables wanes.

Community Sentiment

Important energy issues still exist, but conditions fail to motivate any meaningful attention. Debate between renewable energy projects and preserving Hawaii's unique environment are set aside as the motivation to move ahead with such projects wanes. Community interest in other areas takes the focus away from clean energy.

Economic Conditions

The economy experiences strong growth, as the recovery is rapid.

Population growth, nonfarm job growth, and real income growth all are stronger than baseline forecast.

Population growth rates in Honolulu County, Hawaii County, and Maui County are all somewhat stronger than baseline forecasts, with per year averages of 0.9%, 1.6% and 1.3%, respectively.

Nonfarm jobs growth rates experience annual average rates of 1.5%, 2.3% and 2.0%, respectively in the three counties, about 0.8% faster than the baseline forecast.

Real income expands at an annual rate of 2.3%, 3.0% and 2.7%, respectively for each county, compared with the baseline forecasts of 1.2%, 2.0% and 1.7%, respectively for each country.[34]

Renewable Energy Regulations

The renewable portfolio standards (RPS) are re-examined and the goals are lowered due to the lower oil prices and lack of urgency to move towards relatively higher cost renewables. Sustaining economic growth is the focus. Aging infrastructure is ignored as public and governmental attention focuses on other issues.

Fuel Supply and Prices (oil, biofuels, and natural gas)

The lesser use of low sulfur fuels in Asia and especially in Japan is realized as Japan is able to resolve their nuclear energy debate. Lower than expected oil prices neutralize serious discussions on alternate fuel sources to reduce Hawaii's dependency on oil. Biofuel prices continue to be high due to an absence of technology breakthroughs and the high cost of locally produced biofuels. Natural gas production in North America ramps up as predicted and many new LNG export terminals are permitted and constructed.

[34] *ibid.*

Electricity Demand (self-generation and energy efficiency impact)

The energy efficiency portfolio standards (EEPS) are re-examined and the goals are lowered due to the low oil prices, a lack of urgency to move towards renewables, and a prevailing view that the costs to implement could slow economic growth. Demand for energy grows modestly as the economy grows and customers' desire to self-generate all or part of their needs is reduced. Sales and market penetration of electric vehicles is slower than generally predicted because consumer sentiment towards the relatively lower price of gasoline does not change car purchase behavior.

Energy Incentives

Renewable energy incentives end, causing investment in renewables to deteriorate and, with it, the slowing of new entrepreneurial activity.

Environmental Regulations

There is no political support for greenhouse gas legislation.

Operating Cost (includes maintenance)

Costs escalate at normal rates.

Construction Cost Escalation Rate (includes emerging technologies)

Current renewable energy projects progress slowly or are cancelled. Advancement and adoption of new technology stagnates.

4. Moved by Passion

A world in which oil prices grow from 2012 levels but sentiment to support or expand clean energy goals is driven more by principles than need, especially since the economy is growing. Visionary leadership and a spirit of compromise continue to make Hawaii a leader in renewable energy generation, albeit at a more considered pace.

Community Sentiment

Policy makers and the citizenry have facilitated substantial changes in energy generation despite more stable oil prices and electricity rates. Consumers are engaging in a more thoughtful and considerate discussion about where and how energy is generated and transmitted because they realize that oil prices could increase again. The community's desire to preserve Hawaii's unique environment is balanced with the growing support for using indigenous renewable energy resources as a method to secure energy independence and price stability for future generations because people believe it's the right thing to do. Consumers who have a strong interest in energy diversification and increasing the use of renewable resources lead the discussion, although they sometimes struggle to attract attention due to a lack of urgency and limited innovations.

Economic Conditions

The economy experiences moderate growth over the first decade. Beyond the current decade, economic growth slows as a result of slower growth in major visitor markets, constraints to further visitor capacity growth, and a deceleration in the growth of domestic population for Honolulu, Hawaii, and Maui counties.

The economy continues a gradual process of natural diversification, with the tourism mix evolving toward emerging markets and non-tourism service areas growing as a share of local economic activity.[35]

The three counties experience gradually increasing economic diversification experienced in recent years. Tourism remains a key component in the local economy, however, it becomes somewhat less dominant as an employer than historically. On the other hand, other industries (such as health care and business services) increase. The small sectors of agriculture and manufacturing shrink further in relative importance.[36]

Renewable Energy Regulations

The renewable portfolio standards (RPS) targets remain unchanged.

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[35] *ibid.* 4.

[36] *ibid.* 5.

Fuel Supply and Prices (oil, biofuels, and natural gas)

Hawaii's fuel oil prices continue to increase from the 2012 levels due to continued competition for the same fuels. Biofuel prices remain high due to an absence of technology breakthroughs and the high cost of locally produced biofuels. Natural gas production in North America ramps up as predicted and many new LNG export terminals are permitted and constructed.

Electricity Demand (self-generation and energy efficiency impact)

Economic growth drives the underlying use of electricity higher. The energy efficiency portfolio standards (EEPS) targets are achieved. Electricity demand grows modestly in the short term due to the slower pace for achieving the RPS and EEPS. Because incentives for investing in renewables continue, consumers continue to leave the grid. There is growing interest in electric vehicles (EV) but sales and market penetration grows only at a moderate rate as consumers still prefer hybrid vehicles over EVs.

Energy Incentives

Incentives for investing in renewables continue because it is a policy that in principle supports clean energy goals.

Environmental Regulations

Carbon emission regulations are established through a carbon tax (CO_2 tax). Environmental regulations become more stringent with the advent of emission taxes and penalties.

Operating Cost (includes maintenance)

Operation and maintenance costs increases modestly due to inflationary pressures from a growing economy.

Construction Cost Escalation Rate (includes emerging technologies)

New investment costs increases modestly due to inflationary pressures from the growing economy.

Quantifying the Scenarios

The planning assumptions that will be used in 2013 IRP process were established based on the scenario descriptions. Utility data for sales, peak demand, self-generation levels, fuel prices, and price escalation rates were used to quantify the varying assumptions of the different scenarios. The key policy uncertainties that were described in each scenario were also established.

Summary Table Quantifying the Scenarios

Table 6-1. Summary Table Quantifying the Scenarios

Cost Driver	1. Blazing a Bold Frontier	2. Stuck in the Middle	3. No Burning Desire	4. Moved by Passion
Economic Conditions	Slow Growth	Moderate Growth	Strong Growth	Moderate Growth
Renewable Portfolio Standards (RPS) Energy Regulations	Raised: 2020 at 30% 2030 at 60%	Status Quo: 2020 at 25% 2030 at 40%	Lowered: 2020 at 20% 2030 at 30%	Status Quo: 2020 at 25% 2030 at 40%
Electricity Demand				
♦ *Underlying Economic Sales & Peak (page 6-14)*	Low	Medium	High	Medium
♦ *Customer Renewable Self-Generation (page 6-20)*	Very High	Medium	Low	High
♦ *Energy Efficiency Portfolio Standards–EEPS (page 6-23)*	Exceeded 110% of Base	Partially Achieved 75% of Base	Partially Achieved 75% of Base	Achieved 100% of Base
♦ *Electric Vehicles (page 6-27)*	High	Medium	Low	Medium
Construction Cost Escalation Rate (page 6-29)	General: 3% Renewables: 0%	General: 3% Renewables: 3%	General: 3% Renewables: 3%	General: 3% Renewables: 2%
Fuel Supply & Prices (page 6-30)				
♦ *Oil*	High Forecast	Reference Forecast	Low Forecast	Reference Forecast
♦ *Biofuels*	Low Forecast	High Forecast	High Forecast	High Forecast
♦ *LNG*	High Forecast (high forecast for neighbor islands)	Reference (high forecast for neighbor islands)	Reference (high forecast for neighbor islands)	Reference (high forecast for neighbor islands)
Energy Incentives	Continue	Gradually phased out by 2016	End 2014	Continue
Greenhouse Gas Regulations	CO_2: \$100/ton	CO_2: \$0	CO_2: \$0	CO_2: \$25/ton
Operating Costs	Escalate at 1.87%	Escalate at 1.87%	Escalate at 2%	Escalate at 1.87%

Demand for Electricity and Electricity Sales by Scenario

Each utility must determine the amount of electrical energy to generate to meet customer demand. To do this, the utility forecasts electricity sales and peak demand. Electricity demand continually fluctuates throughout the day. And, at a given instant during a year, this demand reaches its highest level: the peak demand. The utility must be able to generate enough megawatts during peak demand, when customer use is at its greatest.

Figure 6-2 through Figure 6-35 show the utility sales and net system peak demand forecasts by scenario and some of the major factors that influenced the forecasts including:

- Overall sales of electricity
- Underlying economic conditions
- Reduction in sales and peak demand due to amount of renewable self-generation.
- The forecasted impact of the level of Energy Efficiency Portfolio Standard (EEPS) that are achieved. The total level of EEPS impacts are comprised of the Non-Public Benefits Fee Administrator (PBFA) EEPS contributions and the contributions from the PBFA Demand Side Management (DSM) programs.
- Sales growth due to electric vehicles.

Underlying Economic Sales and Peak Forecasts

How the Underlying Sales and Peak Forecasts Were Derived

The Companies derived the long-term sales and peak forecasts using an extensive forecasting effort that uses a comprehensive set of methods. The process incorporates the latest information available at the time the forecasts were developed. Several levels of management, including the executive level, reviewed the forecasts.

UHERO Reports Analyzed

The University of Hawaii Economic Research Organization (UHERO) performed detailed studies of both the short-term and long-term economic outlooks. A major component of the Companies' forecast efforts is a detailed economic forecast. The long-term sales and peak forecasts were based on economic data and forecasts prepared annually by UHERO for the Companies' exclusive use.

The Companies annually invite several local business executives to roundtable discussions on the economy in Honolulu, Hawaii, and Maui counties to gain a deeper understanding of the outlook from the perspective of various business sectors. These roundtable discussions provide a background from which UHERO builds detailed county-level economic forecasts. UHERO provided low, medium, and high economic forecasts for each county. The general long-term trends of the county-level resident population, non-agricultural jobs, and personal income from UHERO's April 2012 forecast were shown graphically at the IRP Advisory Group Meeting #4 on September 24, 2012.

Historical Sales and Peaks Examined

The Companies' forecast process, performed separately by Hawaiian Electric, HELCO, and MECO for their service territories, begins with an examination of historical sales and peaks. The Companies derived the sales forecasts using econometric methods and historical sales data not reduced by demand side management (DSM) program or impacted by customer renewable self-generation. Before applying econometric methods, The Companies further partitioned the historical sales data into sectors: residential, commercial, or rate schedule.

Econometric Analyses Applied

The Companies applied econometric analyses by sector that relates the customers' use of electricity to external drivers. Econometric analysis relies on econometric models that attempt to link sales or customers' use of electricity to macroeconomic variables, such as personal income or jobs, and other variables (including temperature, humidity, or electricity price). Econometric models also incorporate time series parameters such as lagged dependent variables or an autoregressive term. The strength of these models lies in the quantification of the impact of changes in the economic and other variables on electricity sales and use. The Companies also used proprietary software packages to specify and evaluate hypothetical relationships that allowed the Companies to conduct analyses and statistical testing of econometric models. The Companies considered, tested, and rejected many hypothetical relationships before identifying econometric equations for each company and each sector's electricity use or sales for our forecasts. The Companies also added to the econometric forecasts load projections from specific large construction projects that the Companies identified as being outside of normal historical trends

For the long-term forecasts, the Companies relied on growth rates from annual econometric models applied to near-term forecasts developed taking into account island specific information. The Companies derived these near-term forecasts using a number of methods: monthly econometric models, customer-by-customer analysis, construction project information, local (districts or locale vs. county) information, and other methods that reflect more localized knowledge. This type of information is valuable in that it is more specific than macroeconomic data, but it is applicable primarily in the near-term.

Electric Power Research Institute HELM Employed

The Companies apportioned their respective sales forecasts between rate schedules in order to develop peak forecasts based on load profiles by rate schedule. The Companies derived the peak forecasts for Hawaiian Electric and Maui and the long-term peak forecast for HELCO using the Electric Power Research Institute's Hourly Electric Load Model (HELM). HELM uses load profiles by rate schedule from class load studies conducted by each company and the forecasted sales by rate schedule. HELM sums the load profiles adjusted for forecasted sales to produce system profiles. The Companies employed the highest system demands to calculate the annual system peaks. After determining the underlying peak forecast, the Companies made adjustments for standby loads, specific large projects, and other impacts that were outside of the underlying forecasts. The Companies developed the peak forecasts for Lanai and Molokai and the near-term peak forecast for HELCO using a sales load factor methodology that uses the historical relationship between sales and peaks to project the peak forecast based on the sales forecast.

Final Forecast Data

The Companies employed this process to develop the underlying economic forecasts for all 2013 IRP scenarios. To derive the final forecasts, the Companies modify the underlying economic forecasts by adding varied effects of renewable self-generation, EEPS (DSM), and electric vehicles (that is, layers). *Appendix E-1: Quantification of Sales Forecasts* and *Appendix E-2: Quantification of Peak Forecasts* summarize the forecasts by scenario with the layers for each of the three utilities, as well as the underlying economic forecasts and layer forecasts used to derive the 2013 IRP sales and peak forecasts.

Sales Forecast Graphs

These sales forecast graphs depict historical sales and the forecasted sales trends for each of the four scenarios, for each island. See *Appendix E-3: Sales Forecasts Data* for the data used to generate these Sales Forecast graphs (Figure 6-2 through Figure 6-6).

Figure 6-2. HECO Sales Forecast (GWh)

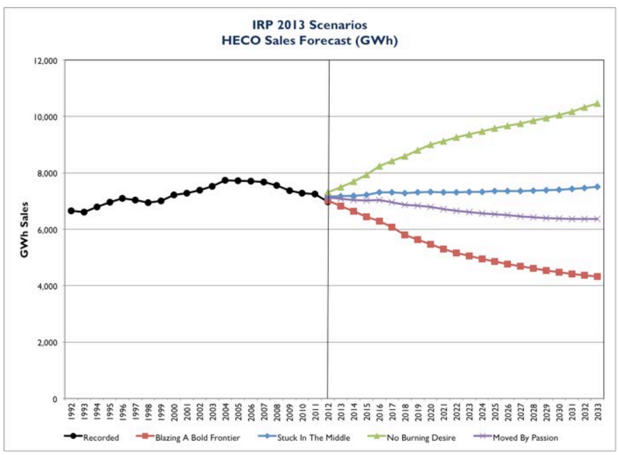


Figure 6-3. HELCO Sales Forecast (GWh)

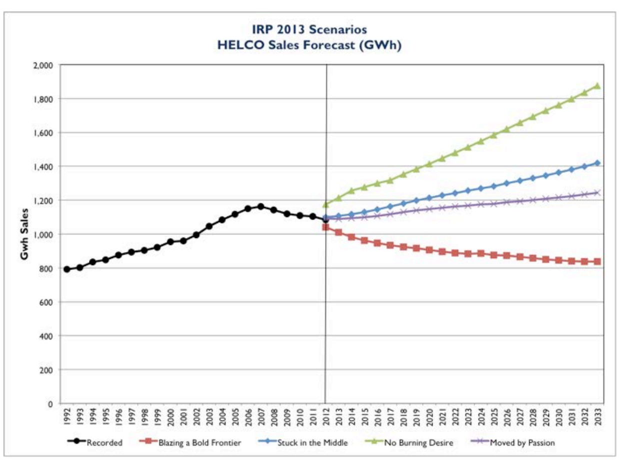


Figure 6-4. Maui Sales Forecast (GWh)

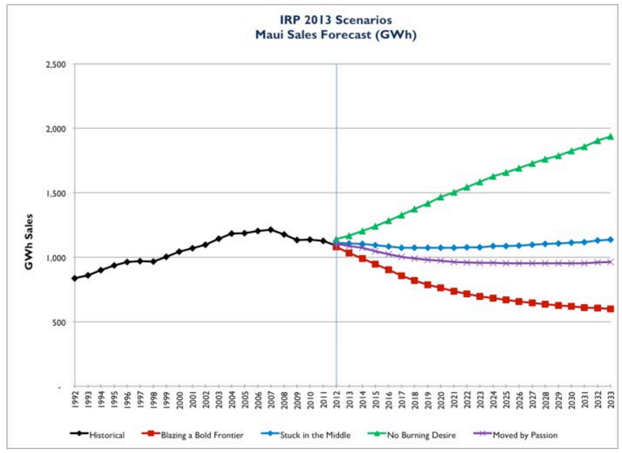


Figure 6-5. Lanai Sales Forecast (MWh)

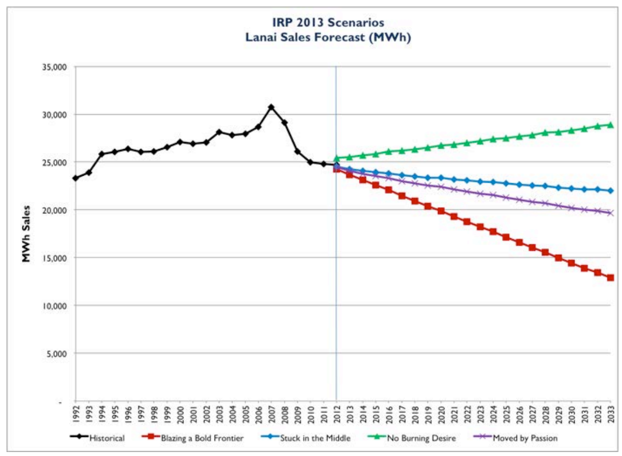
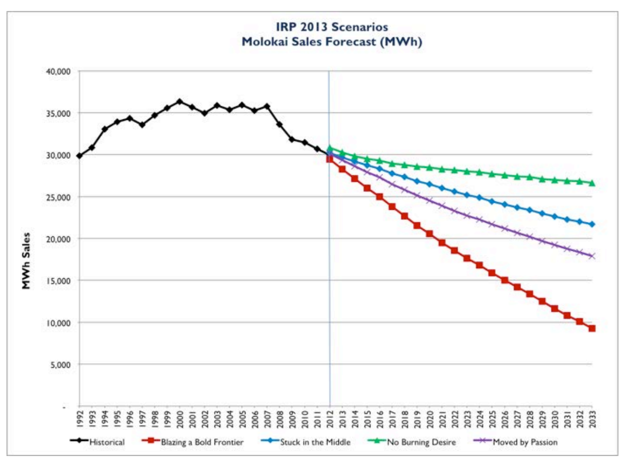


Figure 6-6. Molokai Sales Forecast (MWh)



Peak Forecast Graphs

These peak forecast graphs depict historical peaks and the forecasted peak trends for each of the four scenarios, for each island. See *Appendix E-4: Peak Forecasts Data* for the data used to generate these Peak Forecast graphs (Figure 6-7 through Figure 6-11).

Figure 6-7. HECO Peak Forecast (MW)

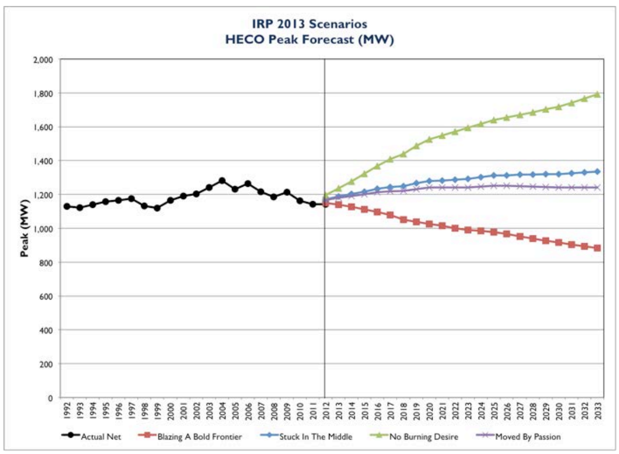


Figure 6-8. HELCO Peak Forecast (MW)

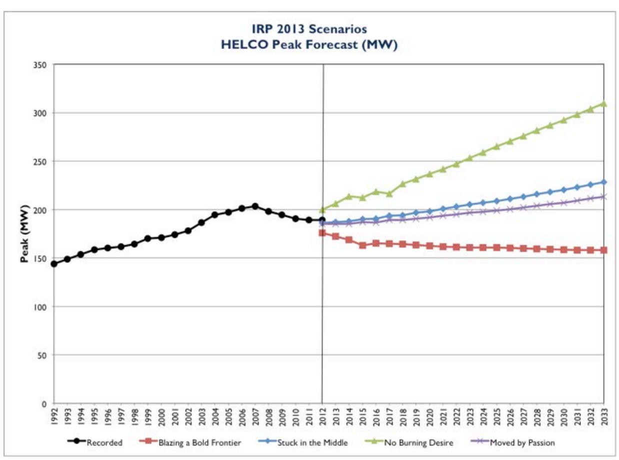


Figure 6-9. Maui Peak Forecast (MW)

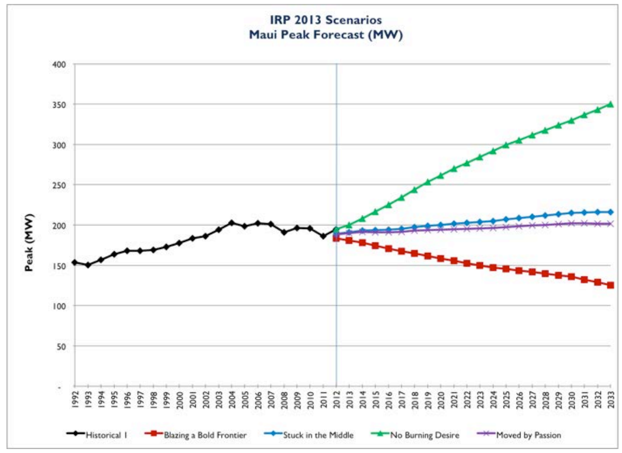


Figure 6-10. Lanai Peak Forecast (MW)

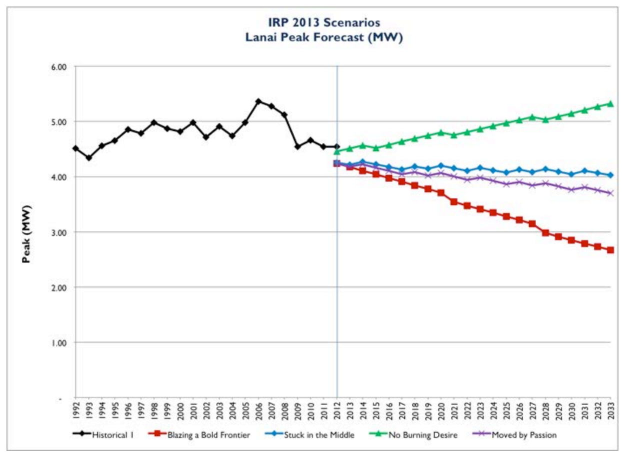
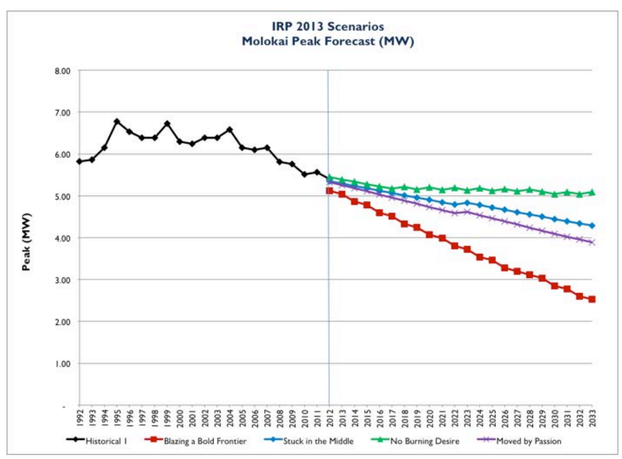


Figure 6-11. Molokai Peak Forecast (MW)



Underlying Economic Forecast Graphs

These underlying economic forecast graphs depict historical data and the forecasted underlying economic trends for each of the four scenarios, for each island. See *Appendix E-5: Underlying Economic Forecasts Data* for the data used to generate these Underlying Economic Forecast graphs (Figure 6-12 through Figure 6-16).

Figure 6-12. HECO Underlying Economic Forecast (GWh)

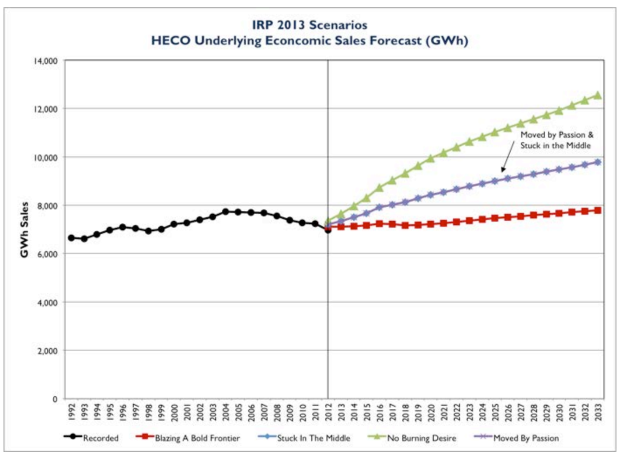


Figure 6-13. HELCO Underlying Economic Forecast (GWh)

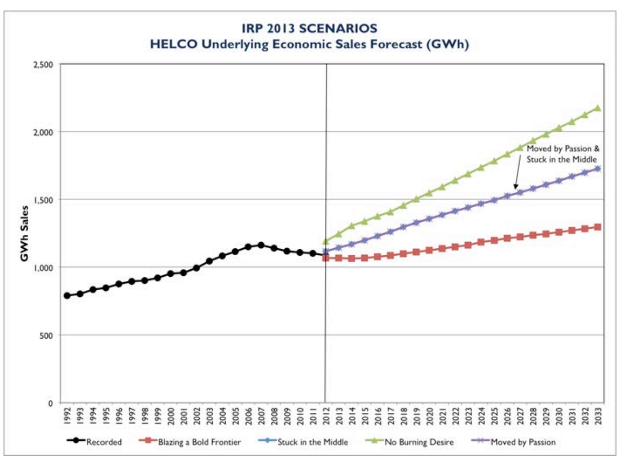


Figure 6-14. Maui Underlying Economic Forecast (GWh)

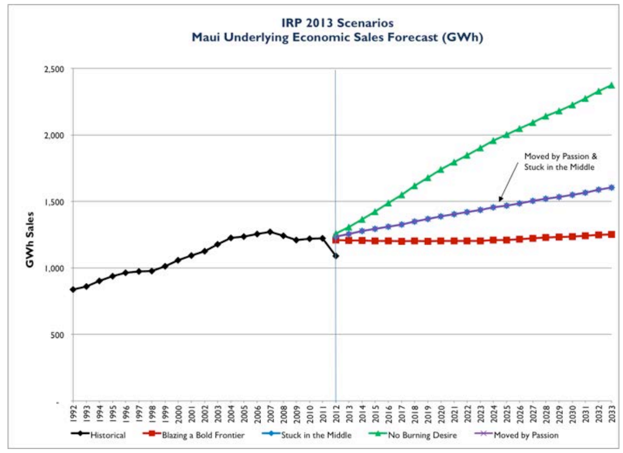


Figure 6-15. Lanai Underlying Economic Forecast (MWh)

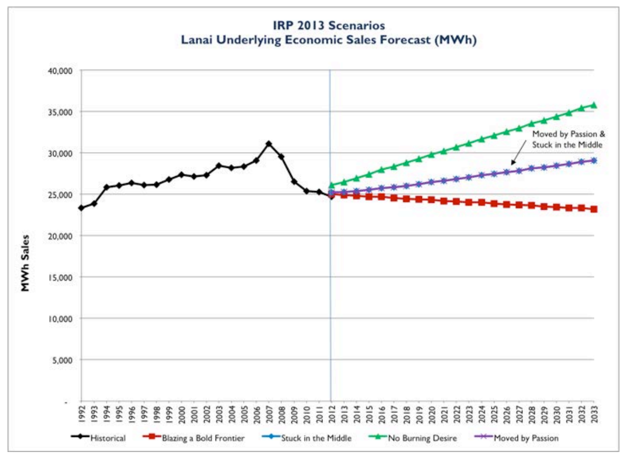
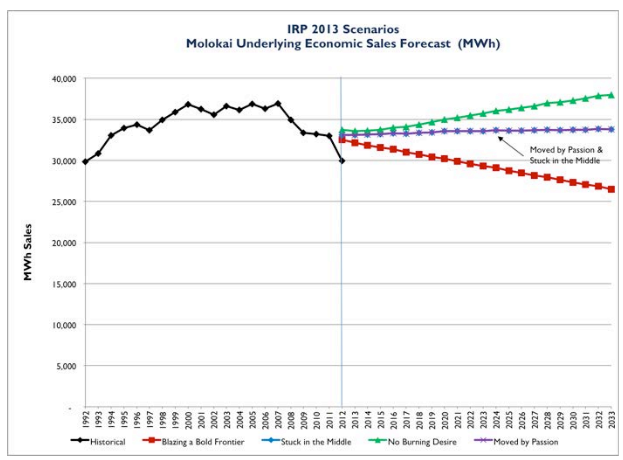


Figure 6-16. Molokai Underlying Economic Forecast (MWh)



Customer Renewable Self-Generation Forecasts

How the Renewable Self-Generation Forecasts Were Derived

The Companies derived the customer-sited renewable self-generation forecasts to project energy sales impacts from Net Energy Metering (NEM), Standard Interconnection Agreement (SIA), and Feed-in-Tariff (FIT) installations. The sales impact represents the estimated total amount of energy generated by NEM and SIA systems plus the estimated amount of FIT generated energy used to satisfy the needs at each FIT installation location (thereby offsetting load rather than selling that energy to the utility)[37].

Data Sources

The Companies based historical sales impact estimates on actual installed kilowatts, and the forecast for future sales impact on projections for new installations. The projections for new installations consider historical installations, current growth rates, known projects in queue, and likely projects planned by large customers. The Companies gathered information on future customer projects from utility discussions with customers about their potential plans for the future. These graphs assume that changes in tax incentives are offset by lower future costs and future new technologies offset grid reliability constraints.

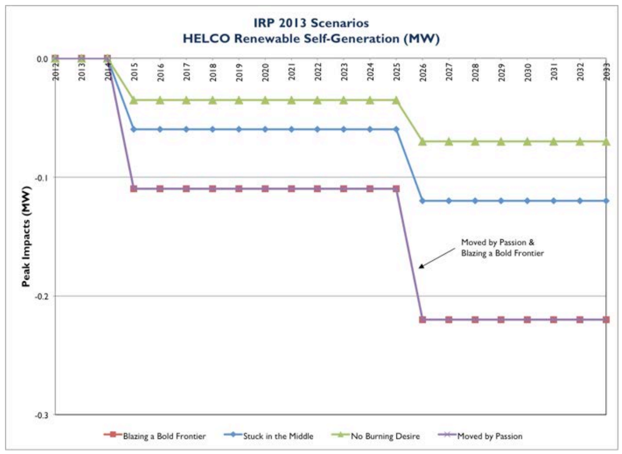
[37] FIT energy that is sold to the utility is not captured in the customer-sited self-generation sales impact. That portion of the FIT energy production is captured as a purchased power supply-side resource. The portion of FIT energy used to offset load is very small in comparison to the amount that is sold to the utility.

Renewable Self-Generation Peak Forecast Graphs

These renewable self-generation forecast graphs depict historical data and the forecasted renewable self-generation trends (plus the peak trends for HELCO) for each of the four scenarios, for each island. See *Appendix E-6: Renewable Self-Generation Forecasts Data* for the data used to generate Figure 6-17 through Figure 6-22.

Hawaiian Electric and MECO renewable self-generation peak forecasts are zero, and thus not shown.

Figure 6-17. HELCO Renewable Self-Generation Peak (MW)



Renewable Self-Generation Forecast Graphs

Figure 6-18. HECO Renewable Self-Generation Forecast (GWh)

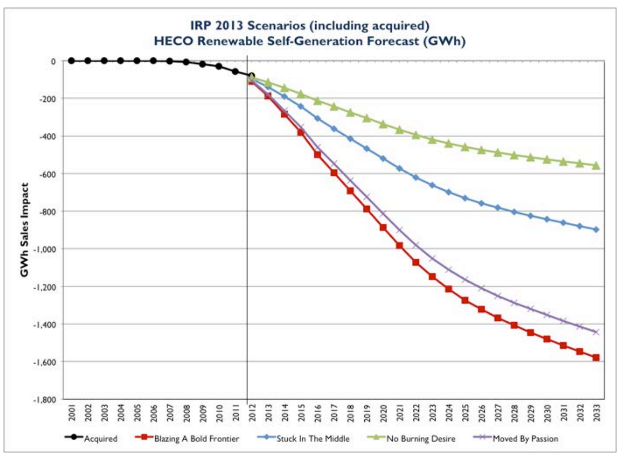


Figure 6-19. HELCO Renewable Self-Generation Forecast (GWh)

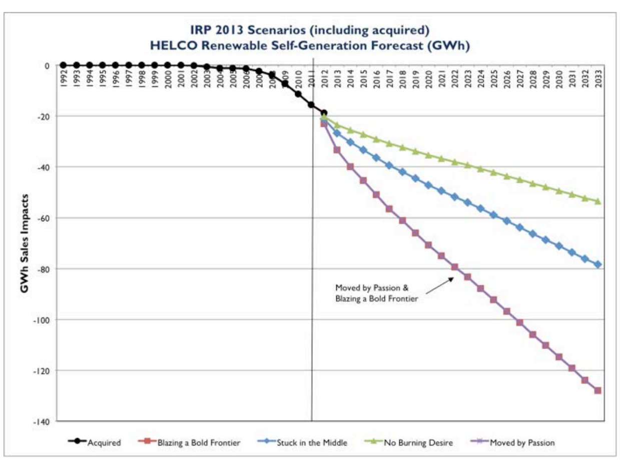


Figure 6-20. Maui Renewable Self-Generation Forecast (GWh)

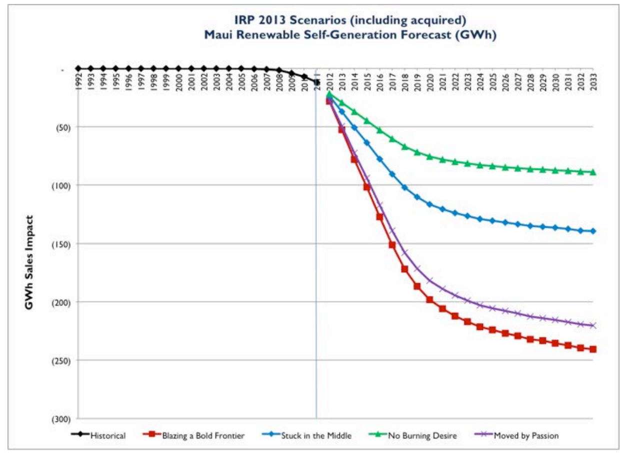


Figure 6-21. Lanai Renewable Self-Generation Forecast (MWh)

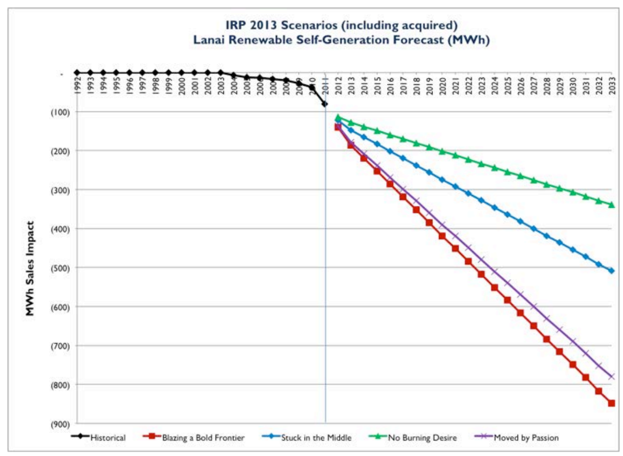
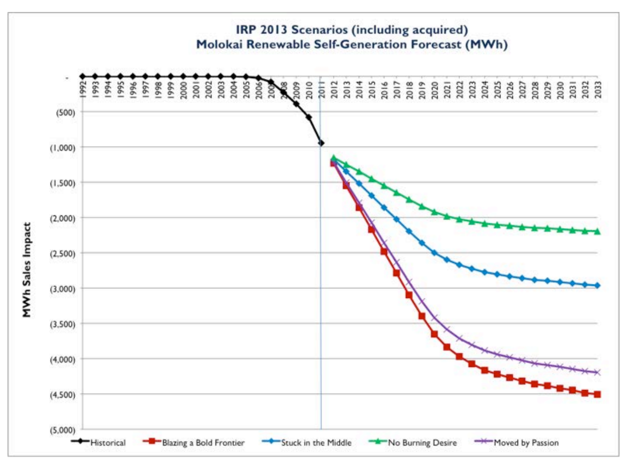


Figure 6-22. Molokai Renewable Self-Generation Forecast (MWh)



Energy Efficiency Portfolio Standards (EEPS) Forecasts

How the EEPS Forecasts Were Derived

The efficient use of electricity is one of the state's energy objectives; therefore, maximizing cost-effective energy efficiency is one of our goals. Energy efficiency programs are designed to reduce energy use through the installation of high efficiency measures and equipment. Energy use is reduced over the lifetime of the energy efficiency measure installed.

The long-term goal of energy efficiency programs is to make the acceptance and use of higher efficiency measures and equipment the norm. On January 3, 2012, the Public Utilities Commission in Decision and Order No. 30089 in Docket No. 2010-0037 approved a framework to govern the achievement of Energy Efficiency Portfolio Standards (EEPS) in the State of Hawaii as prescribed in Hawaii Revised Statutes § 269-96. The EEPS shall be designed to achieve 4,300 GWh of electricity reductions statewide by 2030; this was based on a 30% reduction of forecasted sales in 2030 as provided in HRS § 269-96.

Efficiency measures include a range of programs and activities such as traditional incentive-based programs, education and outreach, implementation of building codes and appliance and equipment standards, system upgrades, and efforts designed to address the market barriers to energy efficiency.

The EEPS Evaluation Measurement & Verification Contractor (EM&V Contractor) and the Public Benefits Fee Administrator (PBFA) provided the Companies a base forecast of the total annual EEPS impacts and allocated those impacts to the Companies by island. The Hawaiian Electric Companies have assumed for the purposes of this IRP that all of the EM&V's and PBFA's EEPS base forecast would be attributed to the Companies since no allocation has been made to other contributing entities such as the Kauai Island Utility Cooperative (KIUC). The total EEPS forecast provided to the Companies includes energy and peak demand savings impacts associated with contributions from Commission's regulated entities and non-regulated entities (see the tables "EM&V and PBFA Base Level EEPS Forecast Data" in Appendix E-7 and "EM&V and PBFA Base Level EEPS Peak Impact Forecast Data" in Appendix E-8). The contribution to the EEPS associated with the regulated entities primarily includes the DSM programs administered by the PBFA. The contribution to the EEPS associated with the non-regulated entities, the non-PBFA EEPS contribution, includes energy savings from building codes, new appliance standards, and Federal and State Government energy savings mandates that are forecasted to occur in outside of the PBFA DSM programs.

The Companies then aligned the different levels of EEPS impacts to correspond to each scenario which are reflected in Table 6-1. Summary Table Quantifying the Scenarios (page 6-13). Each scenario's EEPS impacts were developed by adjusting EM&V's and PBFA's EEPS base forecast to the scenario's level. The Non-PBFA EEPS Contribution and PBFA DSM Programs contributions were both adjusted to obtain EEPS impacts that exceeded the base forecast (110% of base EEPS forecast), achieved the base forecast (100% of base EEPS forecast), or partially achieved the base forecast (75% of base EEPS forecast) and are summarized in *Appendix E-9: Contribution Data for Energy Efficiency (EEPS) Data*).

Energy Efficiency (EEPS) Forecast Graphs

These energy efficiency (EEPS) forecast graphs depict historical data and the forecasted energy efficiency trends for each of the four scenarios, for each island. See *Appendix E-7: Energy Efficiency (EEPS) Forecast Data* for the data used to generate Figure 6-23 through Figure 6-27.

Figure 6-23. HECO Energy Efficiency Forecast (GWh)

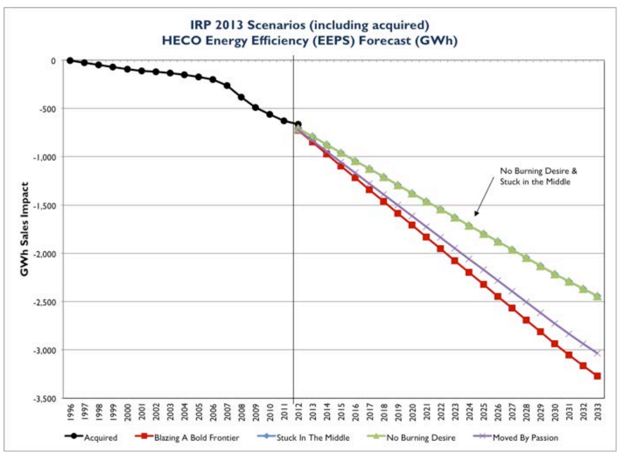


Figure 6-24. HELCO Energy Efficiency Forecast (GWh)

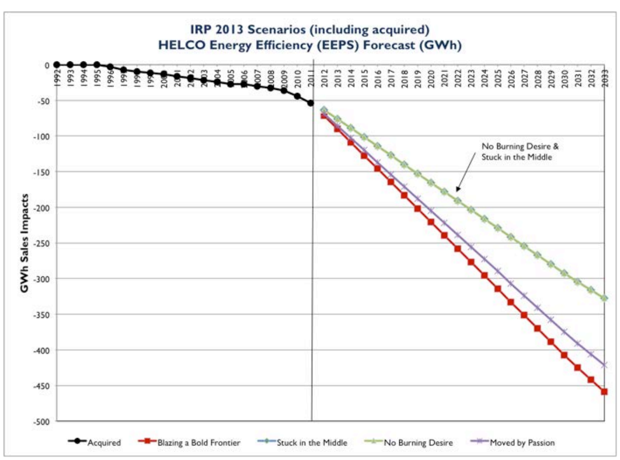


Figure 6-25. Maui Energy Efficiency Forecast (GWh)

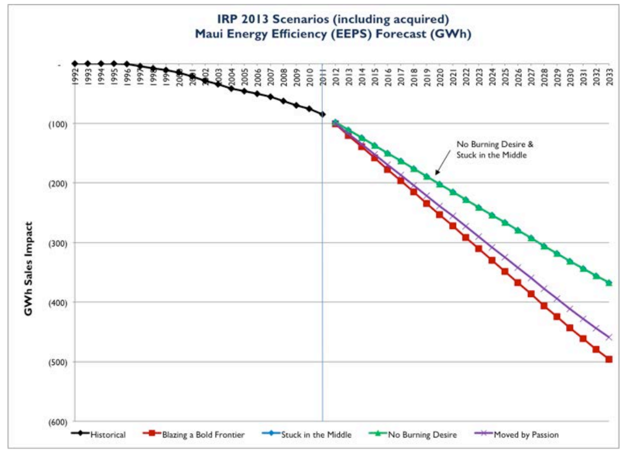


Figure 6-26. Lanai Energy Efficiency Forecast (MWh)

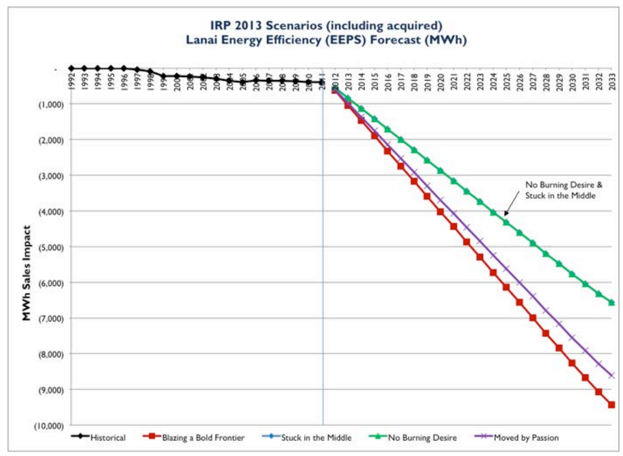
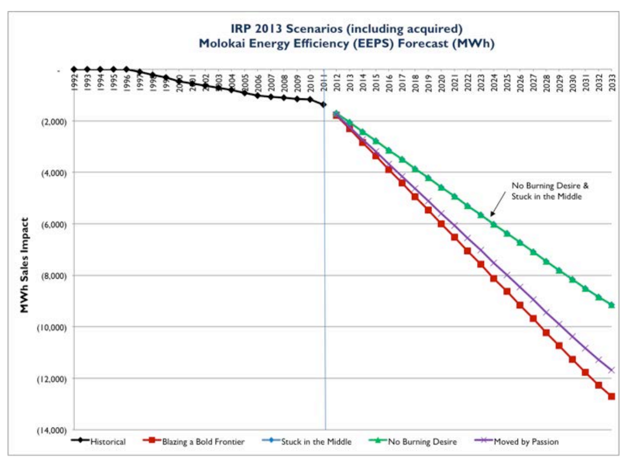


Figure 6-27. Molokai Energy Efficiency Forecast (MWh)



Energy Efficiency (EEPS) Peak Forecast Graphs

These energy efficiency (EEPS) peak forecast graphs depict historical data and the forecasted energy efficiency peak trends for each of the four scenarios, for each island. See *Appendix E-8: Energy Efficiency (EEPS) Peak Forecast Data* for the data used to generate Figure 6-28 through Figure 6-32.

Figure 6-28. HECO Energy Efficiency Peak (MW)

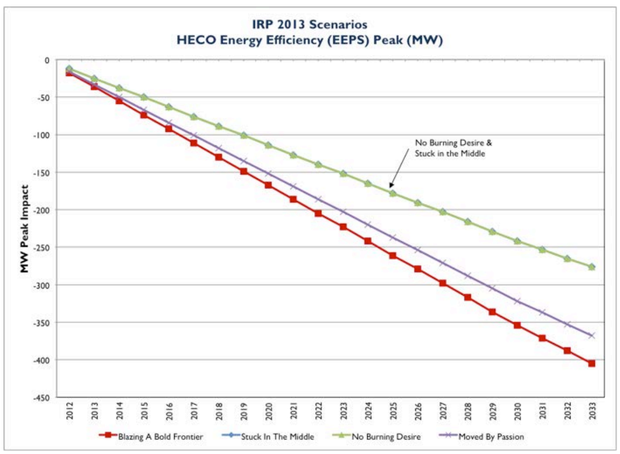


Figure 6-29. HELCO Energy Efficiency Peak (MW)

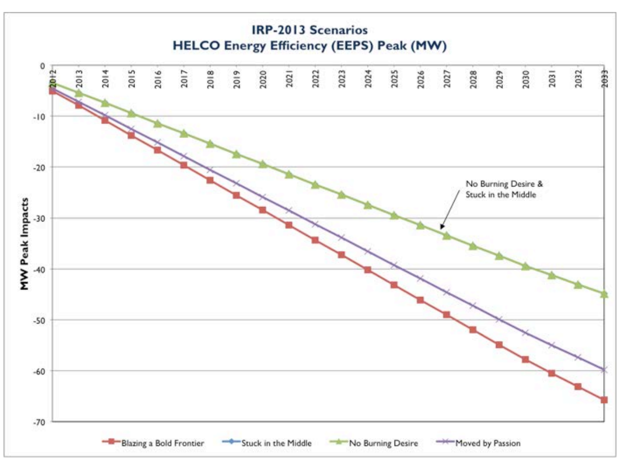


Figure 6-30. Maui Energy Efficiency Peak (MW)

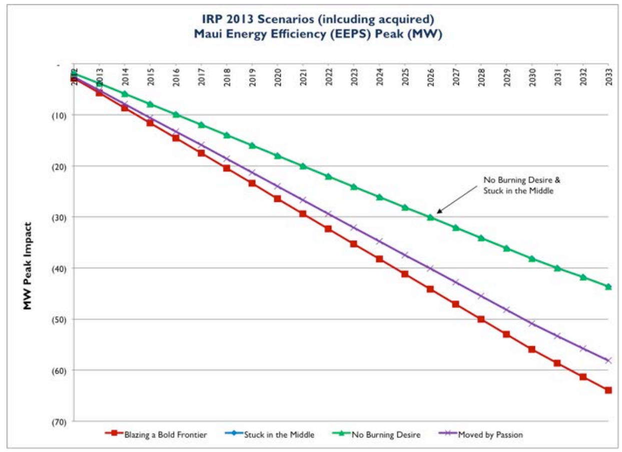


Figure 6-31. Lanai Energy Efficiency Peak (MW)

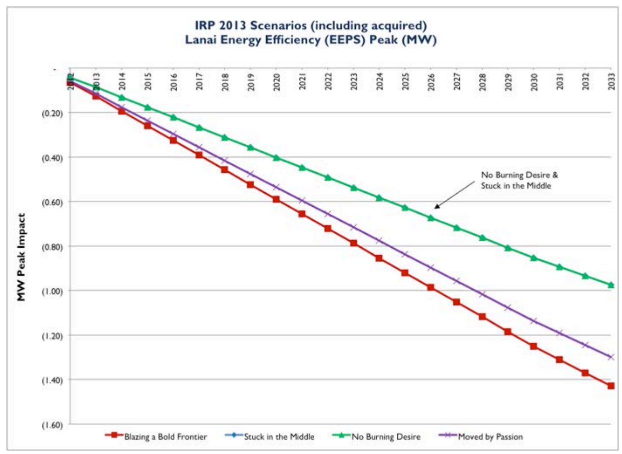
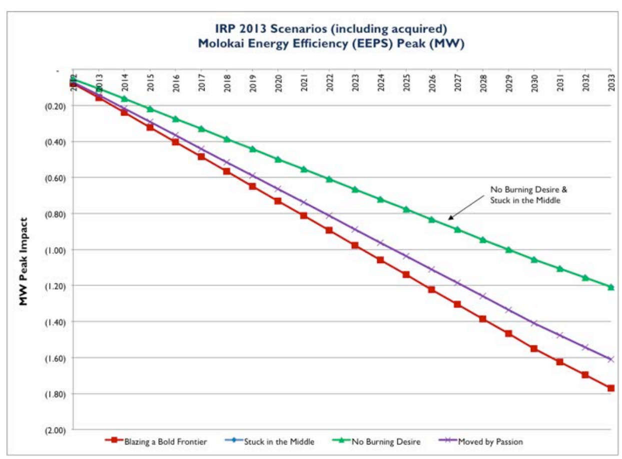


Figure 6-32. Molokai Energy Efficiency Peak (MW)



Electric Vehicle Sales Forecasts

How the Electric Vehicle Forecasts Were Derived

Forecasting electric vehicles (EV) and their impact to sales requires understanding of the EV market — including the buyers' market and access to the product. The impacts on sales, however, is dependent on a number of factors: consumer interest and demand for EVs in this fuel economy, government incentives, industry players, the availability of EVs from the auto manufacturers, as well as regulations at the state and federal level (such as free parking) that give EV ownership significant advantages. Electric vehicle technology is still in its infancy and developing a forecast is difficult at best.

The development of the EV forecasts was based on estimating the number of electric vehicles purchased per year then multiplying that number by an estimate of "typical" electric consumption using charging requirements for plug-in hybrid electric vehicles. Estimating the number of EVs was challenging because the technology is so new and historical data on these newer types of EVs are not available. The following assumptions provide additional details to understanding the development of the forecasts:

1. The statewide vehicle fleet using historical information from the Hawaii Data Book grows at the compound annual growth rate of the previous four years (roughly 4% growth).
2. Plug-in hybrid electric vehicle (PHEV) sales estimates based on the Balducci study from 2011 to 2030 to reach 20% of new car sales by 2030. Only PHEVs are added (that is, no pure EVs) with the expected life of the PHEV to be 13 years.
3. Calculation of the PHEV charging requirements is based the Oak Ridge study (TM-2010-46) which estimates:
    a. One PHEV consumes 2.4 MWh per year.
    b. Roughly 7,300 miles are driven on the electric motor per year (assuming 0.33 kWh/mile).
    c. Estimates for the average annual driving distance for each respective County and island is based on the average annual mileage by county (in accordance with the Hawaii Data Book Table 18.17).
    d. Estimates for "typical" PHEV electric consumption is based on the percentage of 7,300 miles by electric motor compared to the average total annual motor vehicle miles and the balance of the average total annual average motor vehicle miles by county is provided by gasoline.
    e. PHEV charging largely occurs at night after 9:00 PM.
    f. PHEV charging is not expected to significantly affect the annual peak demand.

Electric Vehicles Forecast Graphs

These electric vehicle forecast graphs depict historical data and the forecasted electric vehicles trends for each of the four scenarios, for each island. See *Appendix E-10: Electric Vehicles Forecast Data* for the data used to generate Figure 6-33 through Figure 6-35.

Figure 6-33. HECO Electric Vehicles Forecast (GWh)

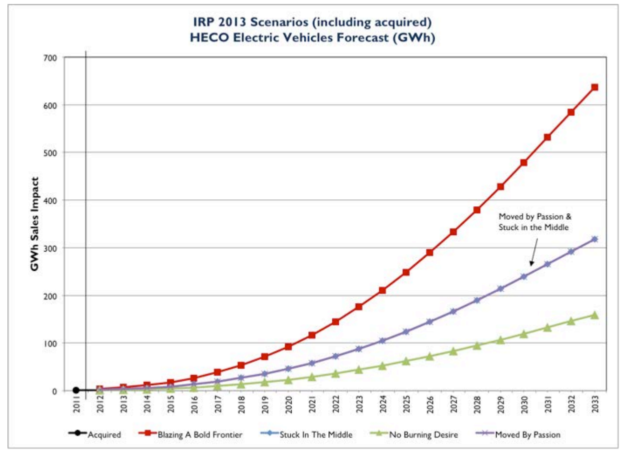


Figure 6-34. HELCO Electric Vehicles Forecast (GWh)

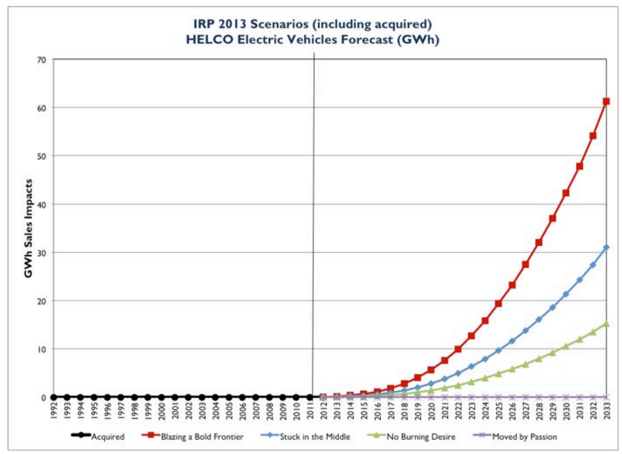
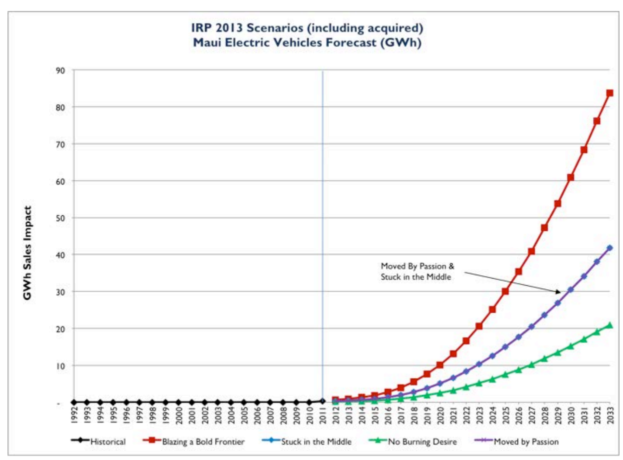


Figure 6-35. Maui Electric Vehicles Forecast (GWh)



Construction Cost Escalation Rate Forecasts

Table 6-1. Summary Table Quantifying the Scenarios (page 6-13) forecasts for the annual growth rate of construction costs. The growth rate of 3% for general construction represents a typical inflation rate. The renewables construction the growth rate was set to be equal to, higher than, or lower than that of general construction in order to be consistent with the story for each scenario. The degree to which the renewables construction cost growth rate is higher or lower than that of general construction were set by the Companies to capture the relative cost difference between technologies.

Utility Cost of Capital and Financial Assumptions

The Hawaiian Electric Companies finance their investments through two main sources of capital: debt (borrowed money) or equity (invested money). In both cases, the Companies pay a certain rate of return for the use of this money. This rate of return is the utility's *Cost of Capital*.

Table 6-2 lists the various sources of capital, their weight (percent of the entire capital portfolio), and their individual rates of return. Composite percentages for costs of capital are presented under the table.

Table 6-2. Utility Cost of Capital

Capital Source	Weight	Rate
Short Term Debt	3.0%	4.0%
Long Term Debt (Taxable Debt)	39.0%	7.0%
Hybrids	0.0%	6.5%
Preferred Stock	1.0%	6.5%
Common Stock	57.0%	11.0%

Composite Weighted Average	9.185%
After-Tax Composite Weighted Average	8.076%

Fuel Supply and Prices Forecasts

The Companies use many different types of fuels to generate power: biodiesel, biocrude, high sulfur diesel, ultra low sulfur diesel, low sulfur fuel oil, medium sulfur fuel oil, low sulfur industrial fuel oil, and liquefied natural gas.

To anticipate the potential cost of producing electricity, the Companies project the cost of various fuels over the next twenty plus years. The utility burns several types of fuel.

- *Biodiesel* refers to a vegetable oil, animal fat, or other renewable liquid-based diesel fuel that can be used as a substitute for petroleum diesel.
- *Biocrude* is raw or unrefined plant oil, animal fat, or other renewable liquefied-based biofuel. This includes crude palm oil based blends.
- *High Sulfur Diesel* contains up to 4,000 parts per million of sulfur; or about 0.4% sulfur content.
- *Ultra Low Sulfur Diesel* (ULSD) contains less than 500 and 15 parts per million of sulfur respectively; or 0.05% and 0.0015% sulfur content.
- *Low Sulfur Fuel Oil* (LSFO) is Hawaiian Electric's primary fuel. It is a residual fuel oil similar to No. 6 fuel oil that contains less than 5,000 parts per million of sulfur; about 0.5% sulfur content.
- *Medium Sulfur Fuel Oil* (MSFO) or Industrial Fuel Oil (IFO) (also known as Bunker Fuel Oil) used by MECO and HELCO contains less than 20,000 parts per million of sulfur; or 2% sulfur content.
- *Low Sulfur Industrial Fuel Oil* (LSIFO) used by MECO and HELCO if a fuel with lower sulfur content than MSFO is needed. It contains up to 7,500 parts per million of sulfur; or about 0.75% sulfur content.
- *Liquefied Natural Gas* (LNG) is a natural gas (a fossil fuel) that has been converted to a liquid, which sharply decreases volume and eases transportation and storage.

How the Fuel Price Forecasts Were Derived

Petroleum-Based Fuel (Not Including LNG)

In general, the Companies derived petroleum-based fuel (not LNG) forecasts by applying the relationship between historical crude oil commodity prices and historical fuel purchase prices to forecasts for the crude oil commodity price. The petroleum-based fuel forecasts reflect U.S. Energy Information Administration (EIA) forecast data for "Imported Crude Oil" and "GDP Chain-Type Price Index" from the 2012 Annual Energy Outlook (AEO2012) year-by-year tables. Historical prices for crude oil are EIA publication table data for the "Monthly Energy Review" and macroeconomic data. Historical actual fuel costs incorporate taxes and certain fuel-related and fuel-handling costs including but not limited to trucking and ocean transport, petroleum inspection, and terminalling fees.

Biofuels

Biofuel forecasts are generally derived by comparing commodity forecasts with recent biofuel contracts and RFP bids to determine adjustments needed to derive each company's respective biofuel price forecast from forecasted commodities. EIA provides low, reference, and high petroleum forecasts, which are used to project low, reference, and high petroleum-based fuel price forecasts. A similar commodity forecast has not been found for biofuels, although EIA might provide one in the future. In lieu of such a source, two entities—The Food and Agricultural Policy Research Institute at Iowa State University (FAPRI) and the World Bank—were used to create pricing estimates based on their commodities forecasts. Therefore, two forecasts were prepared rather than three.

FAPRI and the World Bank was also used to forecast for biodiesel and biocrude prices. FAPRI developed a low biodiesel forecast by using the world biodiesel price minus the U.S. biodiesel price to estimate U.S. biodiesel credits. They developed a biocrude with adders forecast by using soy forecasts. The World Bank also use soy forecasts to develop forecasts for biodiesel and biocrude with adders and subtractions similar to FAPRI's estimated forecast.

Liquefied Natural Gas (LNG)

The Companies do not have historical purchase data for LNG in Hawaii, therefore forecasts were generally derived from EIA fuel commodity forecasts plus adders for liquefaction, shipping, and regasification. The reference forecast represents supply from the U.S. mainland via the Gulf of Mexico, and is based on the EIA forecast for Henry Hub natural gas prices plus adders for liquefaction, shipping from the Gulf of Mexico, and regasification.

The high forecast represents an alternative supply chain from Canada or an LNG supply indexed to the price of oil, which is also used as a proxy for higher cost ISO container supply to the Neighbor Islands. Because Canadian LNG will be oil-price linked, the LNG cost (gas plus liquefaction cost) was calculated at 14.85% of the Japan Crude Cocktail price. The EIA forecast for Brent Crude price was used as the forecast for the Japan Crude Cocktail price. Cost adders for shipping from the West Coast and regasification were included to arrive at a delivered to Hawaii price for LNG.

Fuel Price Projection Graphs and Data Tables

Figure 6-36 through Figure 6-74 depict the fuel price projections for all the fuels used by the Companies, for each of the four scenarios, for each island (depending on the fuel type). See *Appendix E-11: Fuel Costs Forecast Data* for the data used to generate these figures.

Biodiesel

Biodiesel Price per Gallon Forecasts

Figure 6-36. HECO Biodiesel Forecast (Price per Gallon)

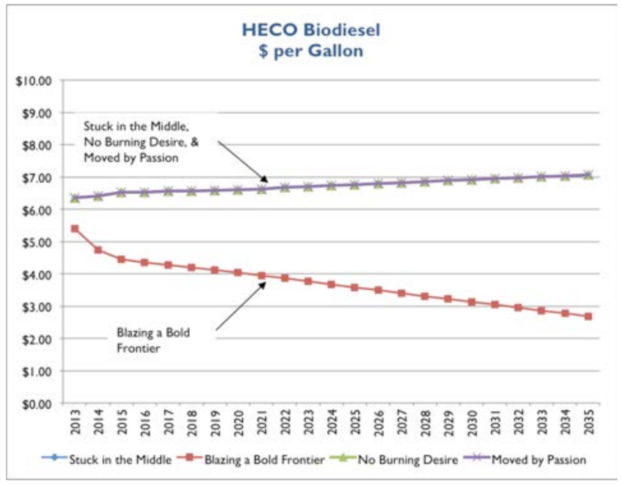


Figure 6-37. HELCO Biodiesel Forecast (Price per Gallon)

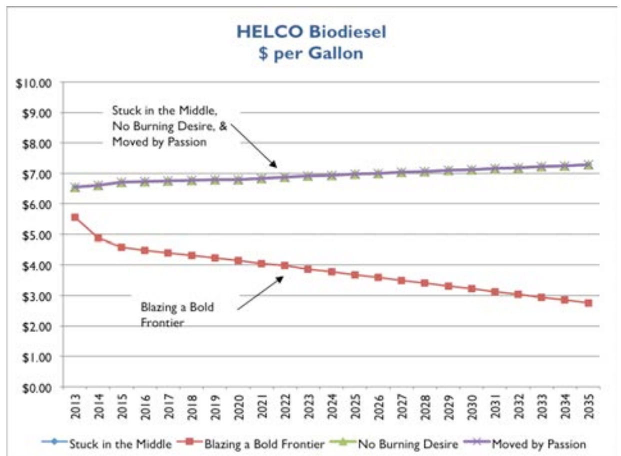
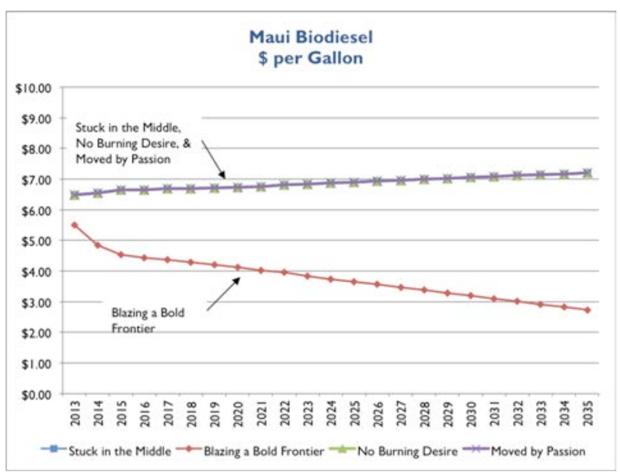


Figure 6-38. Maui Biodiesel Forecast (Price per Gallon)



Biodiesel Price per MMBtu Forecasts

Figure 6-39. HECO Biodiesel Forecast (Price per MMBtu)

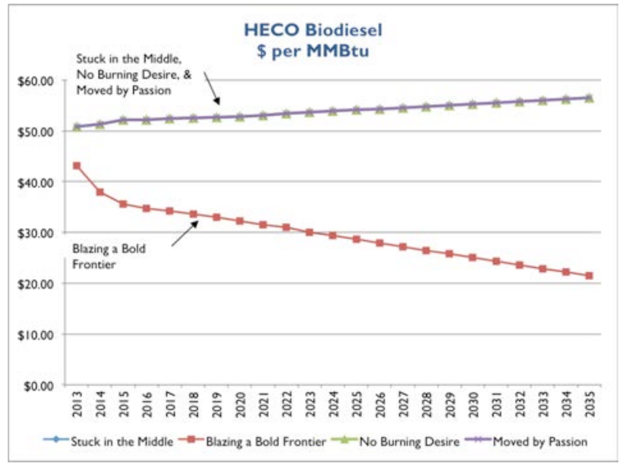


Figure 6-40. HELCO Biodiesel Forecast (Price per MMBtu)

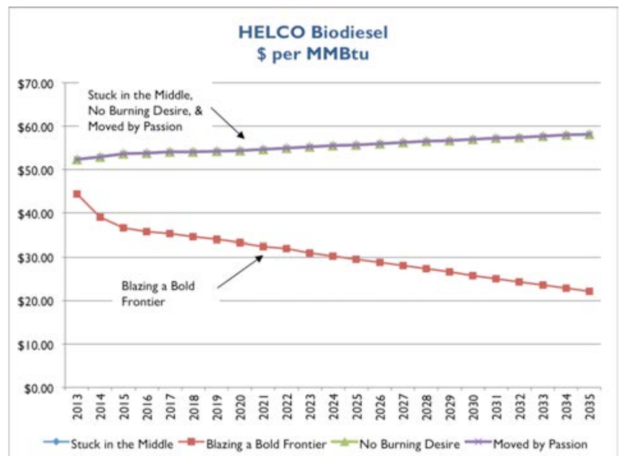
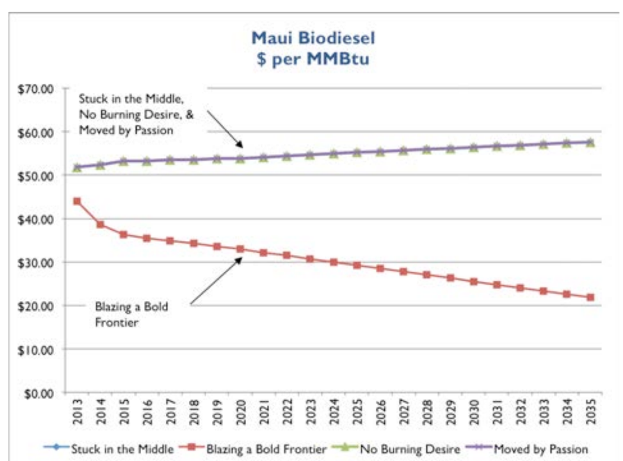


Figure 6-41. Maui Biodiesel Forecast (Price per MMBtu)



Biocrude

Biocrude Price per Gallon Forecasts

Figure 6-42. HECO Biocrude Forecast (Price per Gallon)

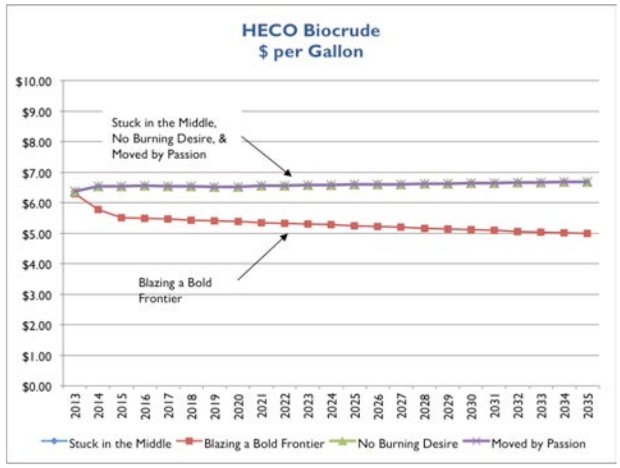


Figure 6-43. HELCO Biocrude Forecast (Price per Gallon)

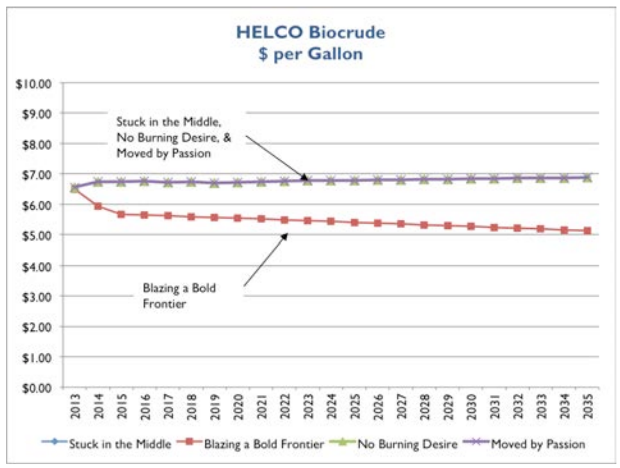
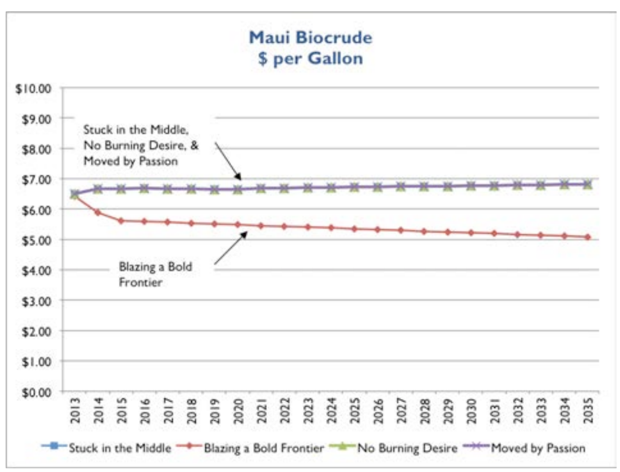


Figure 6-44. Maui Biocrude Forecast (Price per Gallon)



Biocrude Price per MMBtu Forecasts

Figure 6-45. HECO Biocrude Forecast (Price per MMBtu)

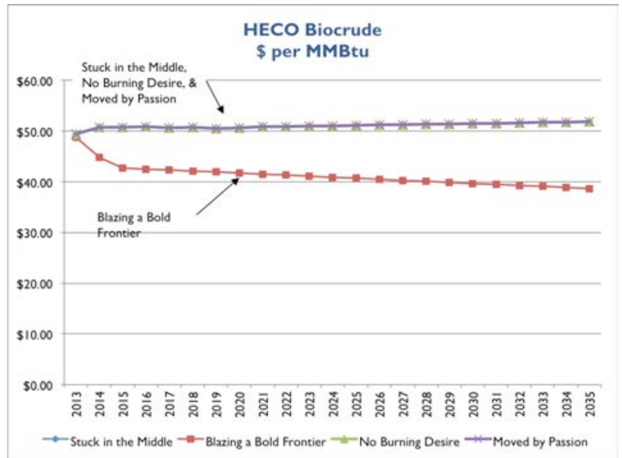


Figure 6-46. HELCO Biocrude Forecast (Price per MMBtu)

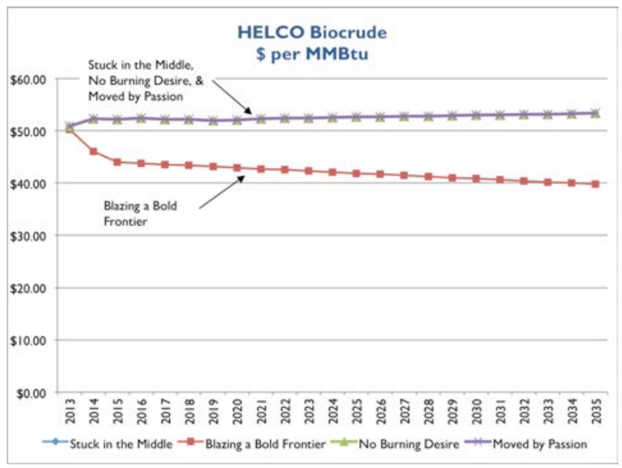
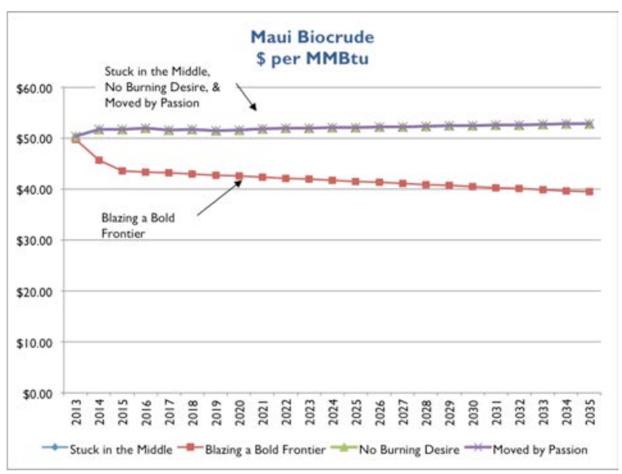


Figure 6-47. Maui Biocrude Forecast (Price per MMBtu)



High Sulfur Diesel

High Sulfur Diesel Price per Barrel Forecasts

Figure 6-48. HECO High Sulfur Diesel Forecast (Price per Barrel)

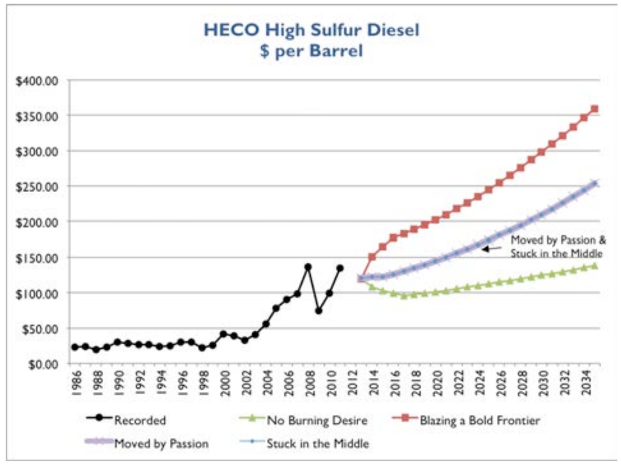


Figure 6-49. HELCO High Sulfur Diesel Forecast (Price per Barrel)

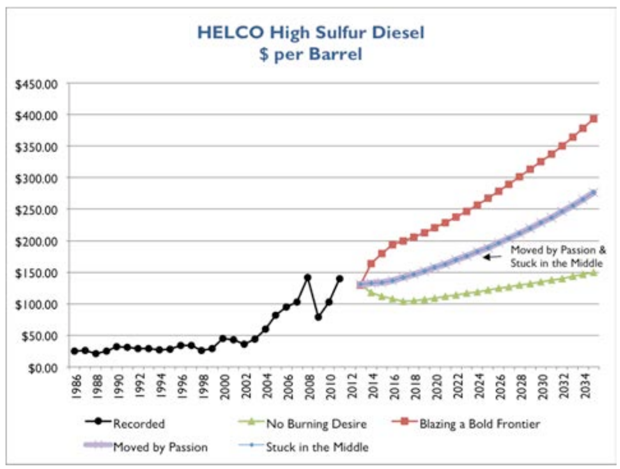
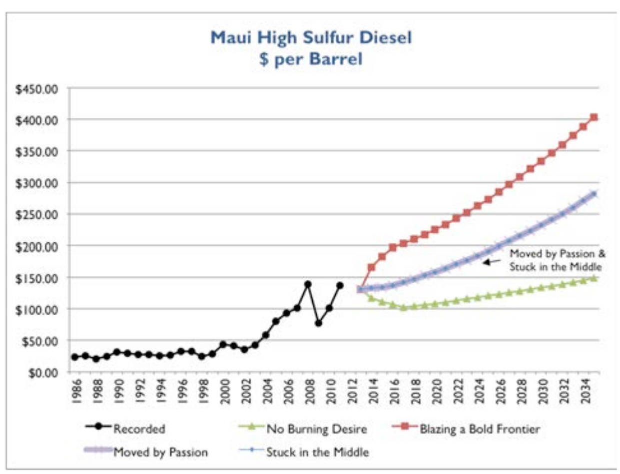


Figure 6-50. Maui High Sulfur Diesel Forecast (Price per Barrel)



High Sulfur Diesel Price per MMBtu Forecasts

Figure 6-51. HECO High Sulfur Diesel Forecast (Price per MMBtu)

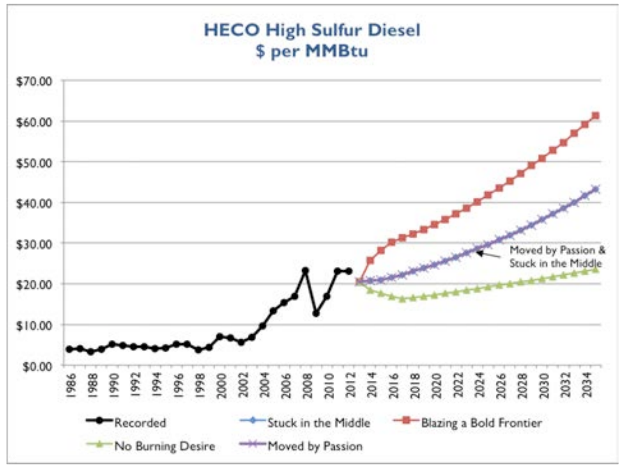


Figure 6-52. HELCO High Sulfur Diesel Forecast (Price per MMBtu)

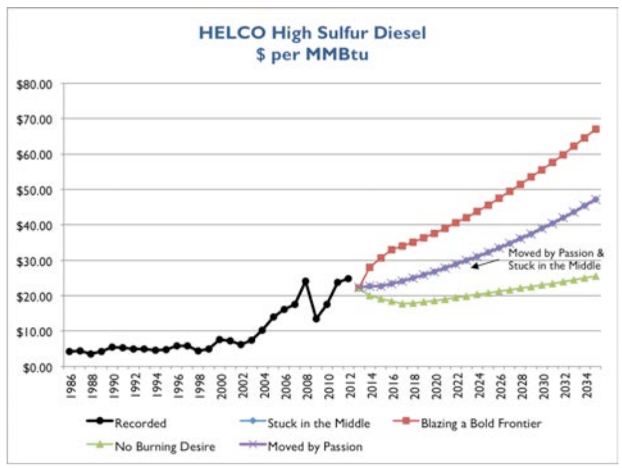
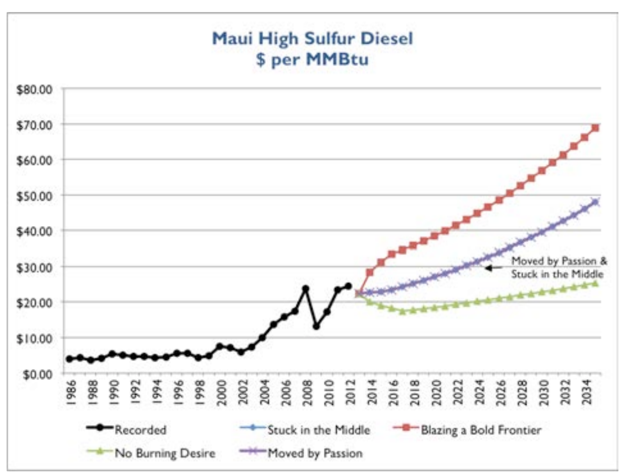


Figure 6-53. Maui High Sulfur Diesel Forecast (Price per MMBtu)



Ultra Low Sulfur Diesel (ULSD)

Ultra Low Sulfur Diesel (ULSD) Price per Barrel Forecasts

Figure 6-54. HECO Ultra Low Sulfur Diesel Forecast (Price per Barrel)

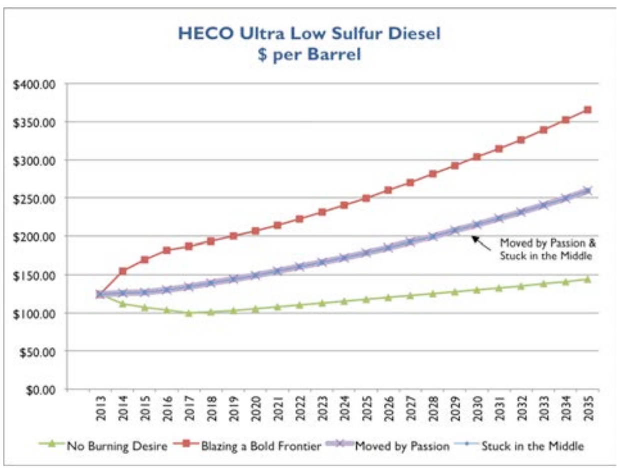


Figure 6-55. HELCO Ultra Low Sulfur Diesel Forecast (Price per Barrel)

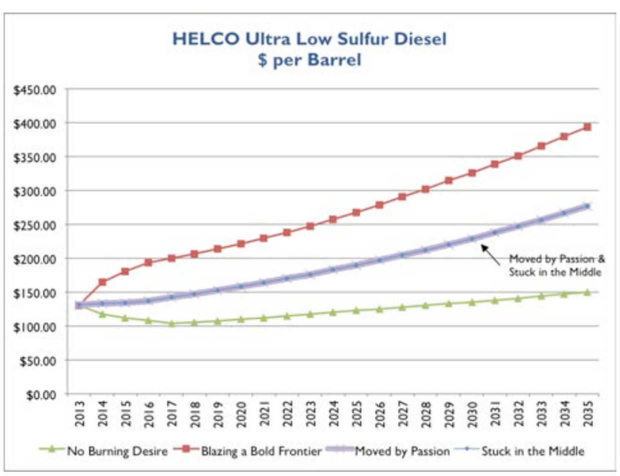


Figure 6-56. Maui Ultra Low Sulfur Diesel Forecast (Price per Barrel)

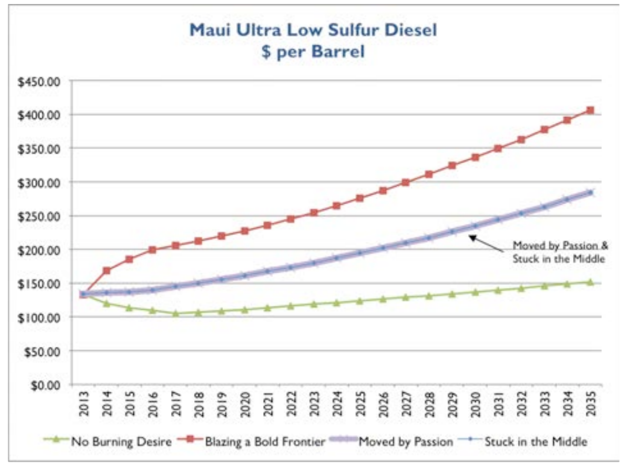


Figure 6-57. Lanai Ultra Low Sulfur Diesel Forecast (Price per Barrel)

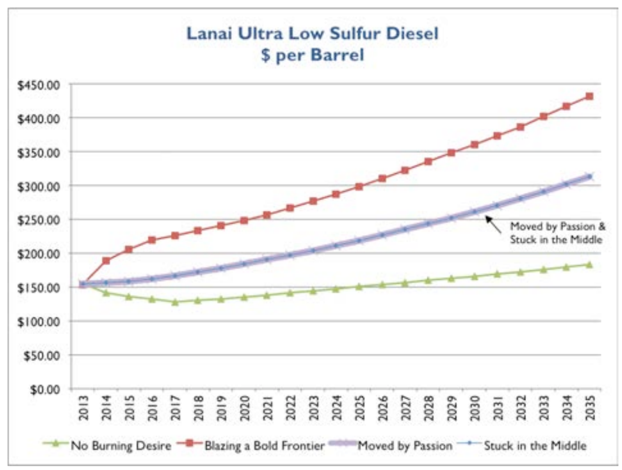
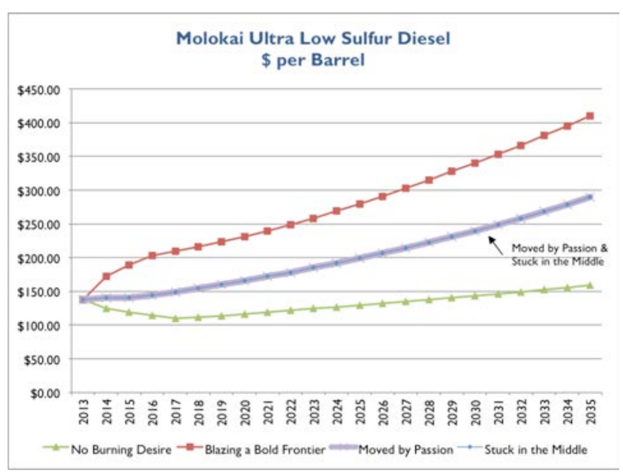


Figure 6-58. Molokai Ultra Low Sulfur Diesel Forecast (Price per Barrel)



Ultra Low Sulfur Diesel (ULSD) Price per MMBtu Forecasts

Figure 6-59. HECO Ultra Low Sulfur Diesel Forecast (Price per MMBtu)

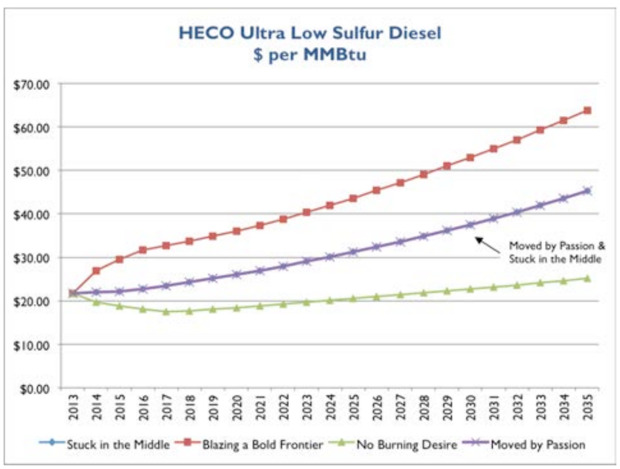


Figure 6-60. HELCO Ultra Low Sulfur Diesel Forecast (Price per MMBtu)

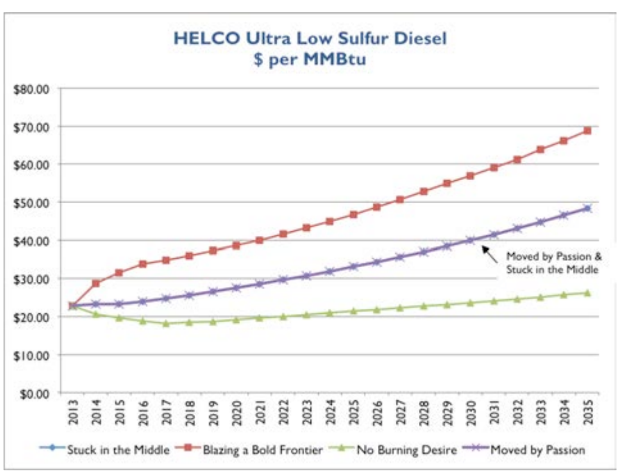


Figure 6-61. Maui Ultra Low Sulfur Diesel Forecast (Price per MMBtu)

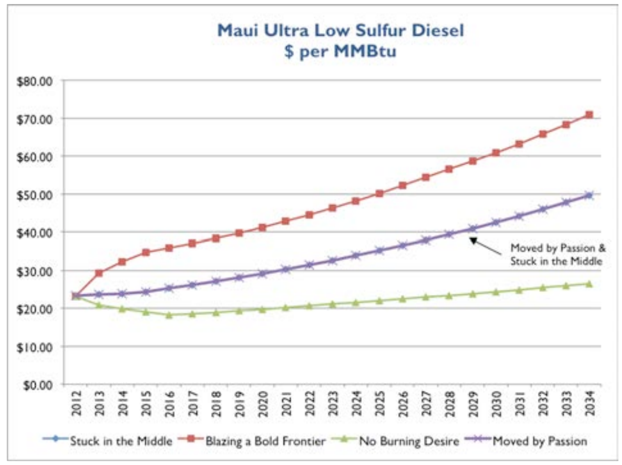


Figure 6-62. Lanai Ultra Low Sulfur Diesel Forecast (Price per MMBtu)

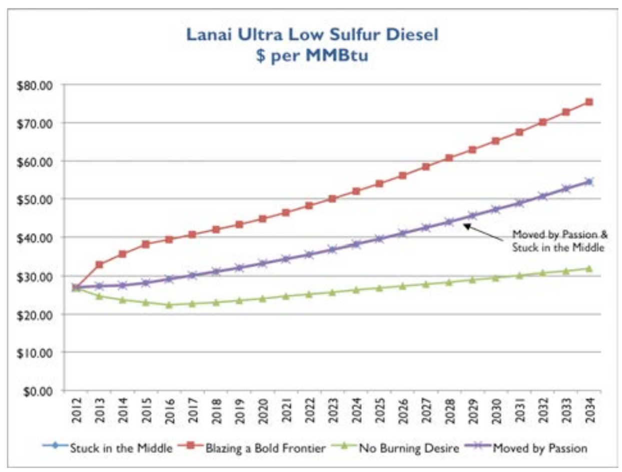
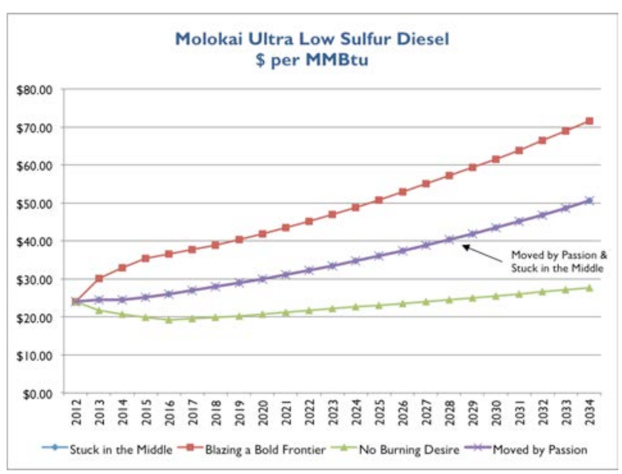
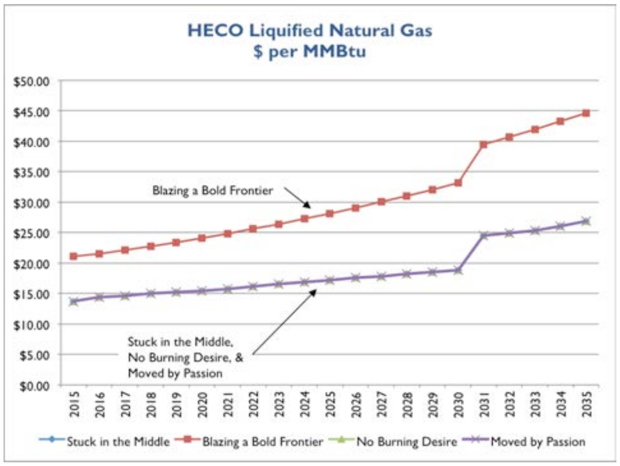


Figure 6-63. Molokai Ultra Low Sulfur Diesel Forecast (Price per MMBtu)



Liquefied Natural Gas (LNG)

Figure 6-64. HECO Liquefied Natural Gas Forecast (Price per MMBtu)



Low Sulfur Fuel Oil (LSFO)

Figure 6-65. HECO Low Sulfur Fuel Oil Forecast (Price per Barrel)

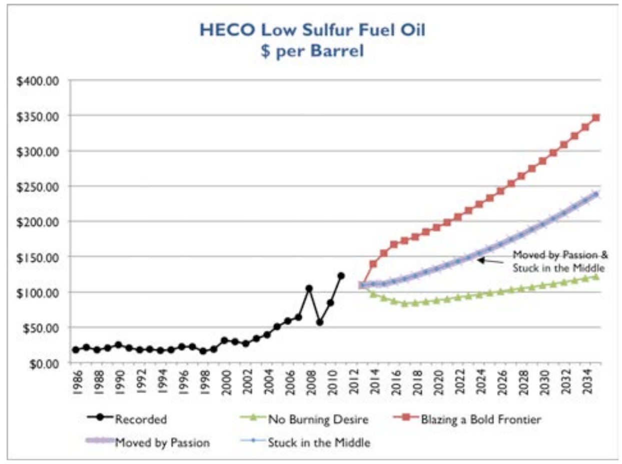
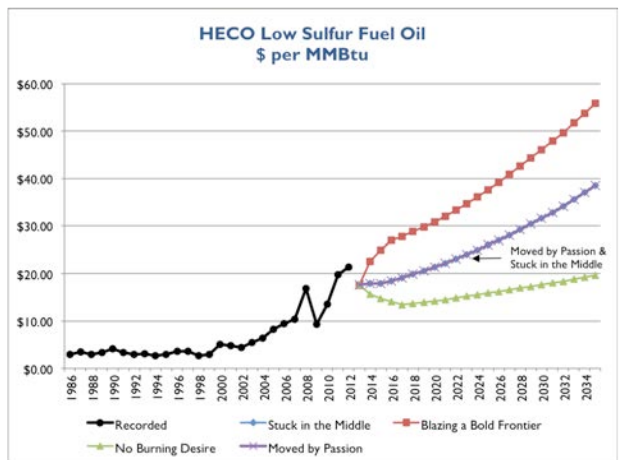


Figure 6-66. HECO Low Sulfur Fuel Oil Forecast (Price per MMBtu)



Medium Sulfur Fuel Oil (MSFO)

Medium Sulfur Fuel Oil Price per Barrel Forecasts

Figure 6-67. HELCO Medium Sulfur Fuel Oil Forecast (Price per Barrel)

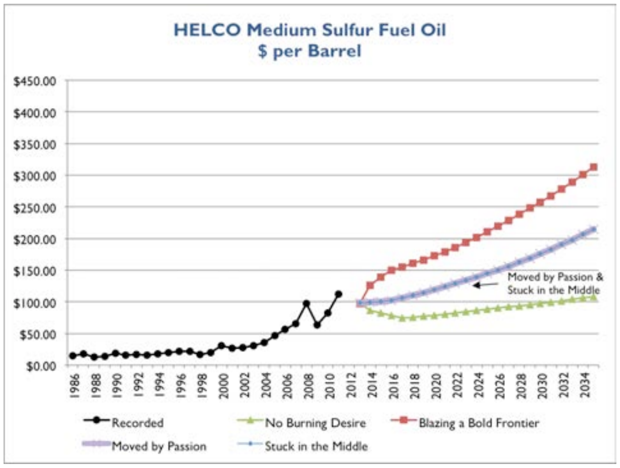
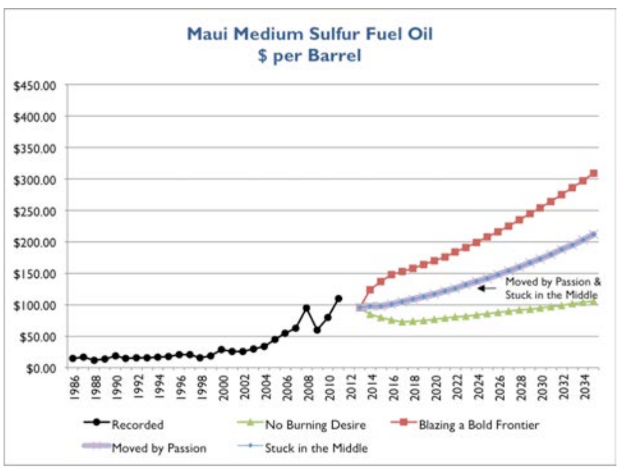


Figure 6-68. Maui Medium Sulfur Fuel Oil Forecast (Price per Barrel)



Medium Sulfur Fuel Oil Price per MMBtu Forecasts

Figure 6-69. HELCO Medium Sulfur Fuel Oil Forecast (Price per MMBtu)

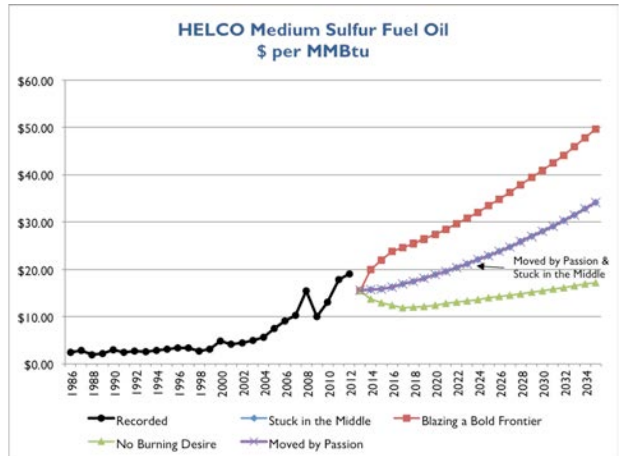
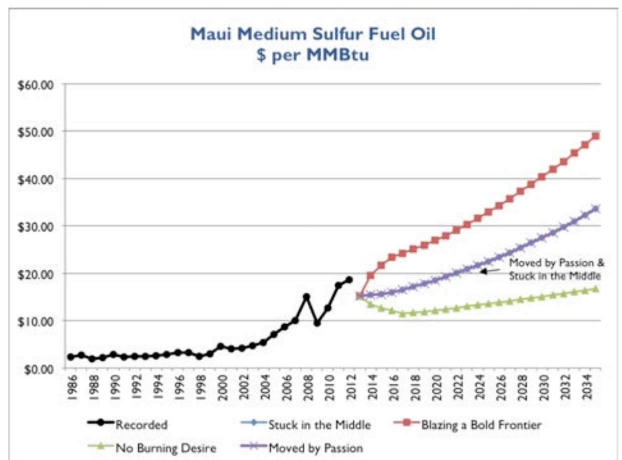


Figure 6-70. Maui Medium Sulfur Fuel Oil Forecast (Price per MMBtu)



Low Sulfur Industrial Fuel Oil (LSIFO)

Low Sulfur Industrial Fuel Oil Price per Barrel Forecasts

Figure 6-71. HELCO Low Sulfur Industrial Fuel Oil Forecast (Price per Barrel)

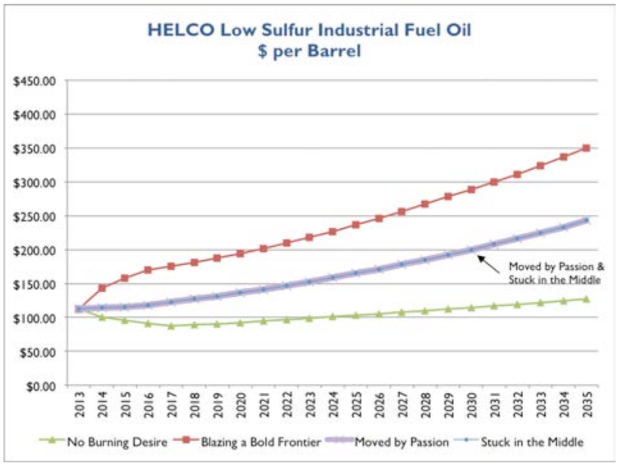
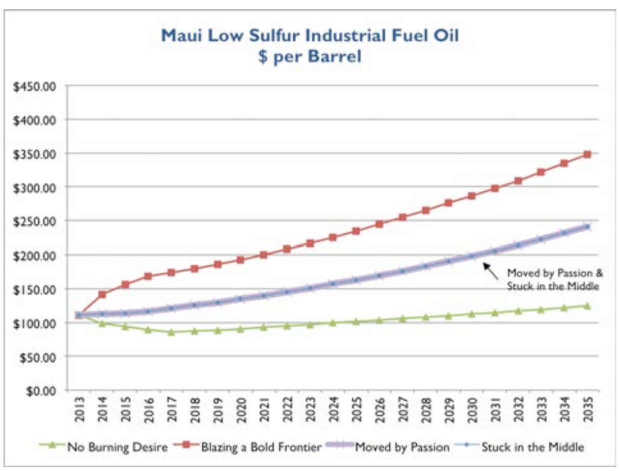


Figure 6-72. Maui Low Sulfur Industrial Fuel Oil Forecast (Price per Barrel)



Low Sulfur Industrial Fuel Oil Price per MMBtu Forecasts

Figure 6-73. HELCO Low Sulfur Industrial Fuel Oil Forecast (Price per MMBtu)

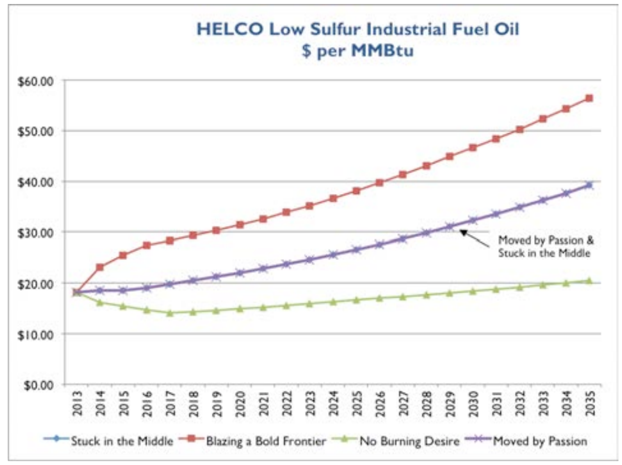
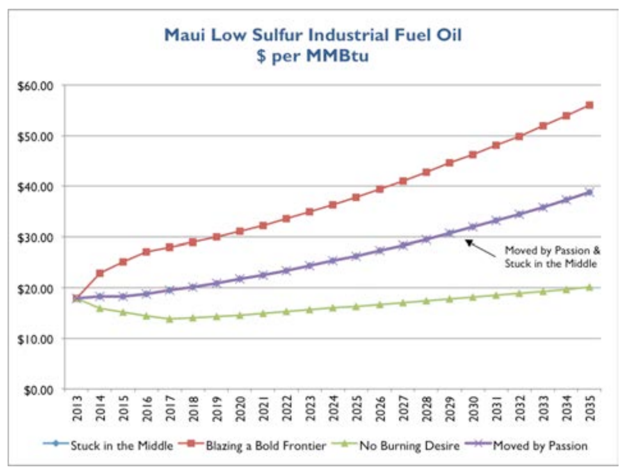


Figure 6-74. Maui Low Sulfur Industrial Fuel Oil Forecast (Price per MMBtu)



Chapter 7: Resource Options

This chapter describes four major resource areas that are integral to the IRP process:

- Existing Generation Resources that describes the generating resources on all five service islands.
- Demand Response Programs that describes the residential, commercial and industrial, and pilot DR programs for the three utilities.
- Demand-Side Management Programs that explains the program managed by the Public Benefits Fee Administrator (PBFA).
- Supply-Side Resource Options outlining the development of the Unit Information Forms (UIFs) with future cost analysis.

Overview

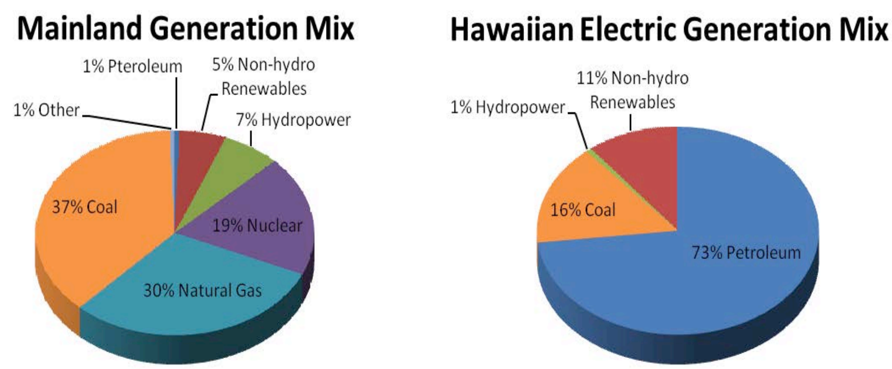
The Hawaiian Electric Companies provide all of the generation required on five islands — Oahu, Maui, Molokai, Lanai, and the island of Hawaii — with three utilities and five grids. This accounts for 95% of all the generation requirements for the entire state of Hawaii.

Hawaiian Electric serves 297,000 customers on Oahu with 1,756 MW (net) of generation. MECO serves 68,000 customers combined on Maui, Molokai, and Lanai with 262 MW (net) generation on Maui, 12 MW (gross) generation on Molokai, and 10.4 MW (gross) generation on Lanai. HELCO serves 81,000 customers on the island of Hawaii with 287 MW (net) of generation.

Generation Mix

The generation mix for the Companies differs greatly from that of the mainland. Approximately 89% of generation on the mainland comes from coal, natural gas, and nuclear. By comparison, approximately 91% of generation by the Companies comes predominantly from petroleum-based fuels.

Figure 7-1. Mainland and Hawaiian Electric Generation Mix Comparison



Currently, natural gas is not available on the islands and nuclear generation has been constitutionally banned. Thus, our long-term energy strategy hinges around reducing our dependency on fossil fuels and replacing it with renewable generation.

This strategy, however, presents a fundamental issue of planning and managing generation from increasing renewable sources: fuel-based generation (such as coal, nuclear, natural gas, and oil) are all dispatchable resources; renewable generation, on the other hand, are comprised of both dispatchable and variable resources.

Renewable Resources

Within the three utilities, the renewable generation varies widely.

Table 7-1. 2012 Renewable Generation Percentages

Island	Renewable Generation
Oahu	7.6%
Maui	20.8%
Hawaii	46.7%
Consolidated	13.9

Interconnecting the Islands

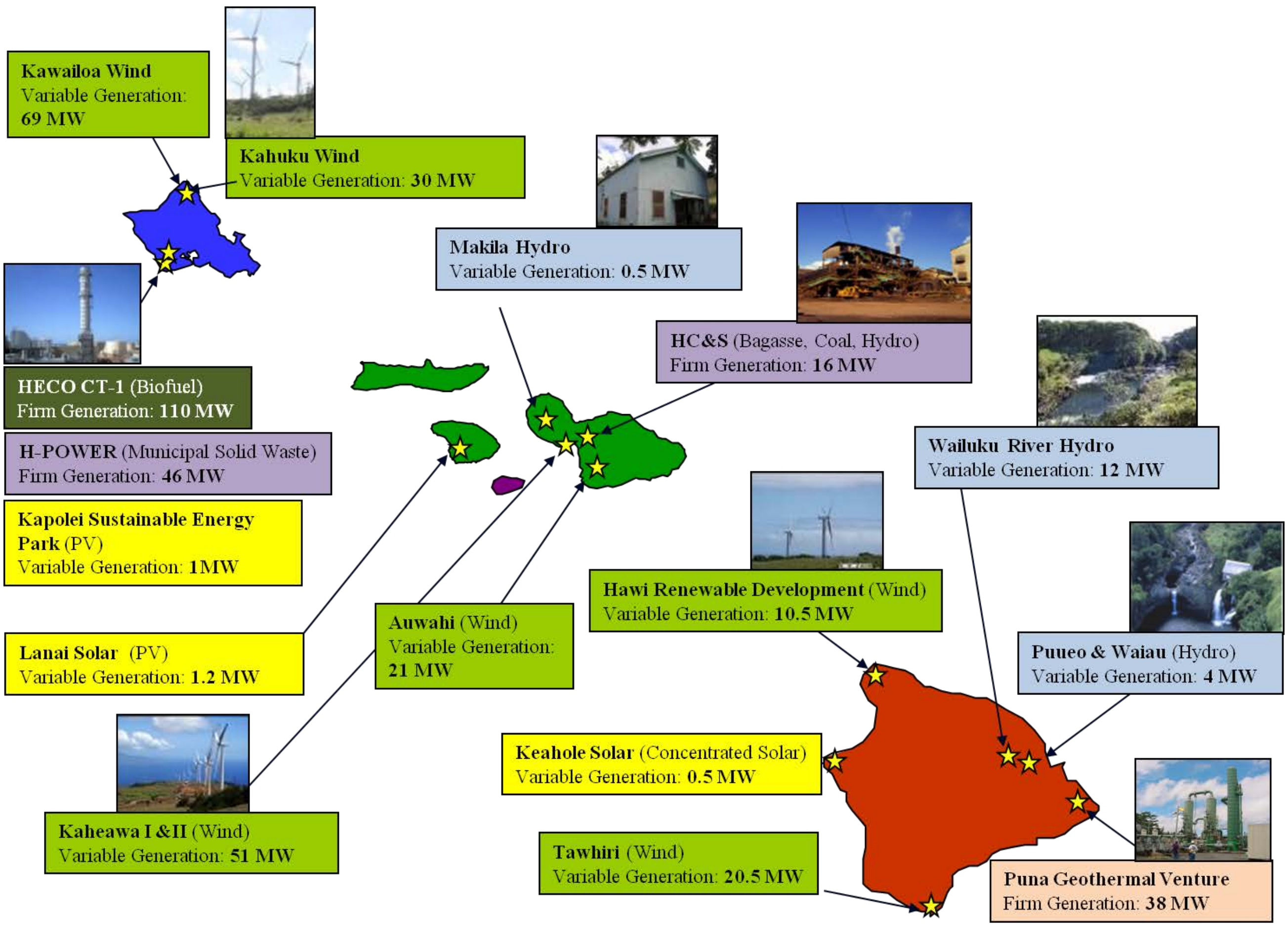
One of the major goals for the Companies is to increase its use of generation from renewable resources. For the Companies and its service area, most of the population, and thus the system load, is on Oahu. Many of the best renewable resources, however, are on the neighbor islands, particularly Maui County and the island of Hawaii.

Currently, there are no interconnections between the islands. An inter-island cable system could transfer renewable energy from neighboring islands to Oahu.

Renewable Generation

The Companies have a number of clean energy generation units across the service area. Figure 7-2 points outs these units and the island where they are sited.

Figure 7-2. Current Clean Energy Resources

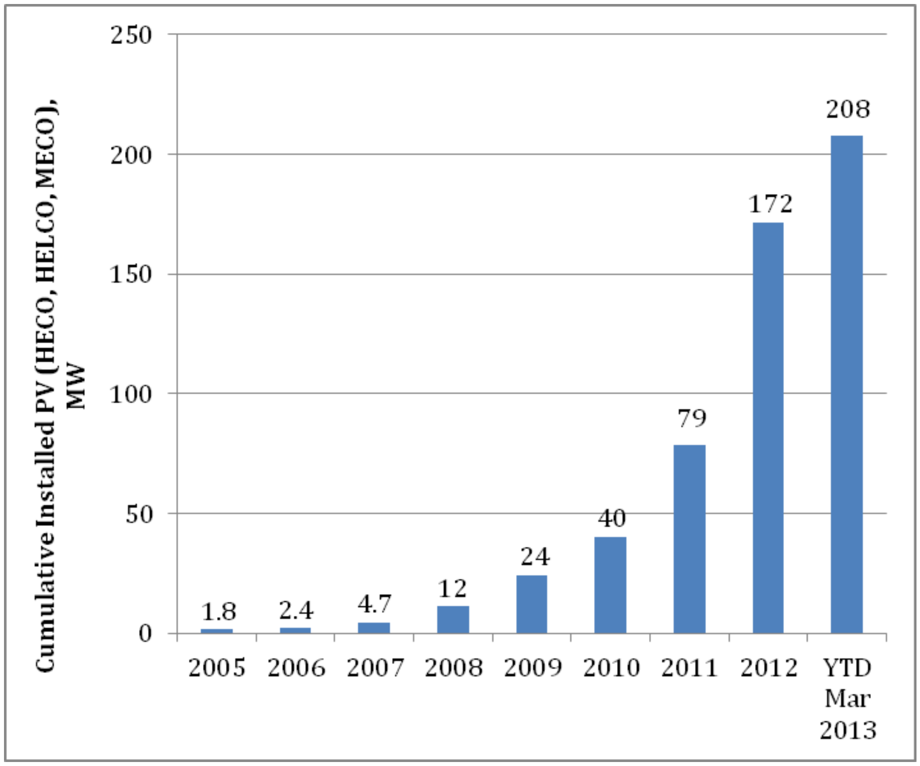


In total, the Companies have 131.2 MW of variable clean generation and 210 MW of firm clean generation.

Photovoltaic Installations

The last ten years have witnessed an explosion in PV generation, mostly from individual distributed generation. By the first quarter of 2012, the amount of megawatts generated has grown over 50 times greater as compared to only seven years earlier (in 2005).

Figure 7-3. Photovoltaic Generation Growth: 2005 to First Quarter 2013



Existing Generation Resources

Hawaiian Electric Generation Units

Hawaiian Electric's generation capacity has a mix of utility-owned generation as well as generation from independent power producers(IPPs).

Utility-Owned Generation

Kahe Generating Station

The Kahe generation station has six steam units, all baseload generation, with a combined nameplate capacity of 651 MW, with 620 MW net generation. These are Hawaiian Electric's most efficient units. The station has black start capability.

Waiau Generating Station

The Waiau generating station has eight units: six are steam units and two are diesel. Two are baseload units; four are cycling units; and two are quick-start combustion turbines. Their combined nameplate capacity is 499 MW, with 481 MW net generation. The station has black start capability.

Honolulu

The Honolulu generating station has two steam units, with a combined nameplate capacity of 113 MW, with 107 MW net generation. Both are cycling units. Located in the downtown load center, these units provide critical transmission support.

Campbell Industrial Park (CIP)

The CIP generation station has one combustion turbine, CT-1, which runs on biodiesel. It provides 113 MW net firm generation. The unit is both quick-start capable and black start capable. This peaker unit runs approximately 10% of the time to address peak load times.

Table 7-2. Oahu Utility-Owned Generation Units

Unit	Fuel	Top Load Ratings MW		Start Date	Delivery Type
		Gross	Net		
Kahe					
Kahe 1	LSFO	92.0	88.2	1963	Baseload
Kahe 2	LSFO	89.0	86.3	1964	Baseload
Kahe 3	LSFO	92.0	88.2	1970	Baseload
Kahe 4	LSFO	93.0	89.2	1972	Baseload
Kahe 5	LSFO	142.0	134.7	1974	Baseload
Kahe 6	LSFO	142.0	133.9	1981	Baseload
Total	—	*650.0*	*620.5*	—	—
Waiau					
Waiau 3	LSFO	49.0	46.2	1947	Baseload
Waiau 4	LSFO	49.0	46.4	1950	Baseload
Waiau 5	LSFO	57.0	54.6	1595	Cycling
Waiau 6	LSFO	56.0	55.6	1961	Cycling
Waiau 7	LSFO	92.0	88.1	1966	Cycling
Waiau 8	LSFO	94.0	88.1	1968	Cycling
Waiau 9	LSFO	53.0	51.9	1973	Quick-start
Waiau 10	LSFO	50.0	49.9	1973	Quick-start
Total	—	*500.0*	*480.8*	—	—
Honolulu					
Honolulu 8	LSFO	56.0	52.9	1954	Cycling
Honolulu 9	LSFO	57.0	54.4	1957	Cycling
Total	—	*113.0*	*107.3*	—	—
Campbell Industrial Park (CIP)					
CT-1	Biodiesel	120.0	113.0		Peaker

IPP Generation

H-Power

The Honolulu Program of Waste Energy Recovery — H-Power — is a municipal solid waste refuse to energy plant that generates 73 MW of baseload, firm generation.

AES

The AES unit is a coal fired plant that generates 180 MW of baseload generation.

Kalaeloa

The Kalaeloa cogeneration (combined cycle) plants that burns LSFO to generate 208 MW of baseload generation.

Kahuku Wind

The Kahuku Wind farm generates 30 MW of variable generation

Kapolei Sustainable Energy Park

The Kapolei Sustainable Energy Park features over 4,000 solar panels that generate 1 MW of variable generation.

Kawailoa Wind

The Kawailoa Wind farm generates 69 MW of variable generation.

Table 7-3. Oahu IPP Generation Units

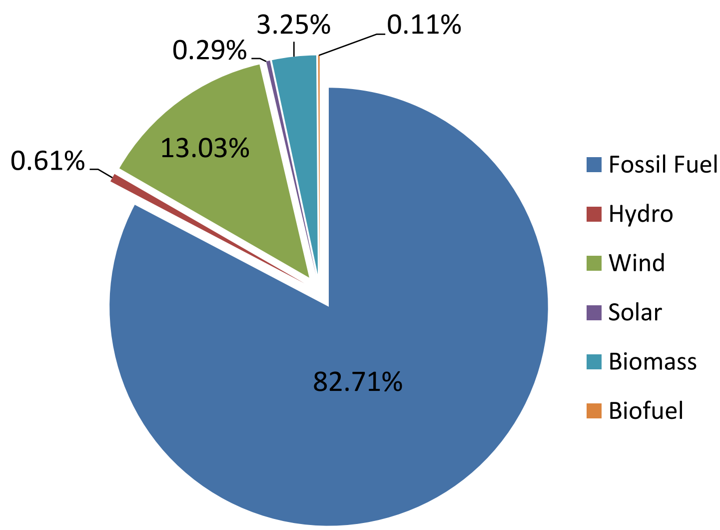
Unit	Fuel	Net MW	Delivery Type
H-Power	Refuse	73	Baseload
AES	Coal	180	Baseload
Kalaeloa	LSFO	208	Baseload
Kahuku	Wind	30	Variable
Kapolei	PV	1	Variable
Kawailoa	Wind	69	Variable
IC Sunshine	PV	5	Variable
Kalaeloa Two	PV	5	Variable

MECO Generation

MECO Generation Mix

MECO generates the majority of its power from combined cycle and internal combustion engine units, as well as a growing portfolio of renewable energy. Maui's total firm capacity is 262.28 MW (net). Lanai's total firm capacity is 10.40 MW (gross). Molokai's total firm capacity is 12.01 MW (gross)

Figure 7-4. MECO Generation Mix



Maui Utility-Owned Generation

MECO owns and operates 27 firm generating units on Maui, totaling 246.2 MW (net), at two generating stations and one distributed generation site.

Kahului Power Plant

The Kahului Power Plant is comprised of four steam units totaling 35.92 MW (net) of firm capacity.

Hana Generators

The two diesel units located at Hana Substation No. 41 total 1.94 MW (net) of firm capacity.

Maalaea Power Plant

The Maalaea Power Plant is comprised of 15 diesel units, a combined cycle gas turbine, and a combined/simple cycle gas turbine. Together they total 208.42 MW (net) of firm capacity.

Table 7-4. Maui Utility-Owned Generation Units

Unit	Fuel	Type	Net-Reserve MW	Net-Normal Top Load MW
Kahului				
K1	Fuel Oil #6	Steam	5.62	4.71
K2	Fuel Oil #6	Steam	5.77	4.76
K3	Fuel Oil #6	Steam	12.15	10.98
K4	Fuel Oil #6	Steam	12.38	11.88
Total KPP			*35.92*	*32.33*
Hana				
H1	Diesel	Diesel	0.97	0.97
H2	Diesel	Diesel	0.97	0.97
Maalaea				
M1	Diesel	Diesel	2.50	2.50
M2	Diesel	Diesel	2.50	2.50
M3	Diesel	Diesel	2.50	2.50
M4	Diesel	Diesel	5.51	5.51
M5	Diesel	Diesel	5.51	5.51
M6	Diesel	Diesel	5.51	5.51
M7	Diesel	Diesel	5.51	5.51
M8	Diesel	Diesel	5.48	5.48
M9	Diesel	Diesel	5.48	5.48
M10	Diesel	Diesel	12.34	12.34
M11	Diesel	Diesel	12.34	12.34
M12	Diesel	Diesel	12.34	12.34
M13	Diesel	Diesel	12.34	12.34
M14, M15, M16	Diesel	Combined Cycle Gas Turbine	56.78	56.78
M17, M18, M19	Diesel	Combined/Simple Cycle Gas Turbine	56.78	56.78
X1	Diesel	Diesel	2.50	2.50
X2	Diesel	Diesel	2.50	2.50
Total MPP			208.42	208.42
Total Utility Owned			*246.28*	*242.69*

As of December 31, 2012 there was also 114.3 MW of capacity from renewable sources on Maui, Lanai and Molokai.

Table 7-5. Renewable Generation on Maui, Lanai and Molokai as of December 31, 2012

Unit	Energy	Rating MW	Type
Hawaiian Commercial & Sugar (Maui)	Bagasse, Coal, Hydro	12.0 4.0	Firm Supplemental
Kaheawa I (Maui)	Wind	30.0	Variable
Kaheawa II (Maui)	Wind	21.0	Variable
Makila Hydro (Maui)	Hydro	0.5	Variable
Auwahi (Maui)	Wind	21.0	Variable
La Ola Solar (Lanai)	Solar PV	1.2	Variable
NEM and FIT (Maui, Lanai, Molokai)	Mostly Solar PV	25.0	Variable

Lanai Utility-Owned Generation

Lanai has capacity to generate 10.4 MW (gross) of power at the Lanai Power Plant.

Table 7-6. Lanai Utility-Owned Generation Units

Unit	Fuel	Type	Gross-Reserve MW	Gross-Normal Top Load MW
LL1	Diesel	Peaking	1.00	1.00
LL2	Diesel	Peaking	1.00	1.00
LL3	Diesel	Peaking	1.00	1.00
LL4	Diesel	Peaking	1.00	1.00
LL5	Diesel	Peaking	1.00	1.00
LL6	Diesel	Peaking	1.00	1.00
LL7	Diesel	Firm Capacity	2.20	2.20
LL8	Diesel	Firm Capacity	2.20	2.20
Manele Bay CHP	Diesel	Firm Capacity	1.00	0.83
Total	–	–	*10.40*	*10.23*

Miki Basin Units LL-l 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 Utility-Owned Generation

Molokai has capacity to generate 12.0 MW (gross) of power at the Palaau Power Plant.

Table 7-7. Molokai Existing Generation Units

Unit	Fuel	Type	Gross-Reserve MW	Gross-Normal Top Load MW
Palaau #7	Diesel	Firm Capacity	2.2	2.20
Palaau #8	Diesel	Firm Capacity	2.2	2.20
Palaau #9	Diesel	Firm Capacity	2.2	2.20
Palaau #10	Diesel	Firm Capacity	2.2	2.20
Palaau #1	Diesel	Peaking	1.25	1.25
Palaau #2	Diesel	Peaking	1.25	1.25
Palaau #3	Diesel	Peaking	0.97	0.97
Palaau #4	Diesel	Peaking	0.97	0.97
Palaau #5	Diesel	Peaking	0.97	0.97
Palaau #6	Diesel	Peaking	0.97	0.97
Total	–	–	*12.01*	*12.01*

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.

HELCO Generation

HELCO currently owns and operates 24 firm generating units, totaling about 182 MW (net), at five generating stations and four distributed generation sites. Five steam units fueled with No. 6 fuel oil (MSFO) are located at the Shipman, Hill, and Puna Generating Stations. Ten diesel engine generators fueled with diesel fuel are located at the Waimea, Kanoelehua, and Keahole Generating Stations. HELCO's five combustion turbines (CT) fueled with diesel fuel are located at the Kanoelehua, Keahole, and Puna Generating Stations. The Keahole CTs are configured to operate in combined cycle with heat recovery steam generators and a steam turbine. Four distributed generation diesel engines fueled with diesel fuel are located (one each) at the Panaewa, Ouli, Punaluu, and Kapua substations.

HELCO also currently owns and operates two run-of-river hydro facilities at Puueo and Waiau.

There are two independent power producers that provide firm capacity power to the HELCO grid. One is a combined-cycle power plant owned and operated by Hamakua Energy Partners L.P. (HEP). The other is a geothermal power plant owned and operated by Puna Geothermal Ventures (PGV). In addition to the two firm capacity independent power producers, there are several independent power producers that furnish power to the HELCO grid on a non-firm, variable basis.

HELCO Utility-Owned Firm Generation

HELCO generates 194.1 MW of firm generation from its utility-owned units.

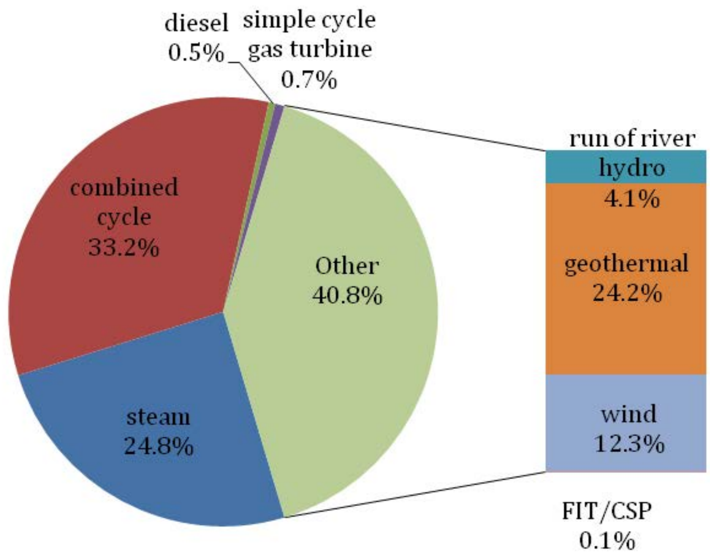
Table 7-8. HELCO Utility-Owned Firm Generation (Net to System)

Unit	Delivery Type	Fuel	Top Load Rating MW	Reserve Rating MW	Start Date
Hill 5 (Kanoelehua)	Baseload	MSFO	13.5	13.5	1965
Hill 6 (Kanoelehua)	Baseload	MSFO	20.2	20.2	1974
Kanoelehua 11	Peaking	Diesel	2.0	2.0	1962
Kanoelehua 15	Peaking	Diesel	2.5	2.75	1972
Kanoelehua 16	Peaking	Diesel	2.5	2.75	1972
Kanoelehua 17	Peaking	Diesel	2.5	2.75	1973
Kanoelehua CT-1	Peaking	Diesel	11.5	11.5	1962
Kapua D-27	Peaking	Diesel	1.0	1.0	1997
Keahole 21	Peaking	Diesel	2.5	2.75	1983
Keahole 22	Peaking	Diesel	2.5	2.75	1983
Keahole 23	Peaking	Diesel	2.5	2.75	1987
Keahole CT-2	Intermediate	Diesel	13.8	13.8	1989
Keahole CT-4/CT-5/ST-7	Intermediate	Diesel	56.25	56.25	2004
Ouli D-25	Peaking	Diesel	1.0	1.0	1997
Paneawa D-24	Peaking	Diesel	1.0	1.0	1997
Puna	Baseload	MSFO	15.7	15.7	1970
Puna CT-3	Intermediate	Diesel	21.0	21.0	1992
Punaluu D-26	Peaking	Diesel	1.0	1.0	1997
Shipman 3	Intermediate	MSFO	7.1	7.1	1955
Shipman 4	Intermediate	MSFO	7.3	7.3	1958
Waimea 12	Peaking	Diesel	2.5	2.75	1970
Waimea 13	Peaking	Diesel	2.5	2.75	1972
Waimea 14	Peaking	Diesel	2.5	2.75	1972

HELCO Renewable Generation

HELCO's renewable energy comprises 49% of its total generation, which doesn't include energy efficiency measures or solar water heating.

Figure 7-5. HELCO Renewable Energy Mix: May 2013



HELCO generates almost 86 MW of power from renewable sources.

Table 7-9. HELCO Renewable Energy Resources

Unit	Energy	Net MW	Delivery Type
Puueo No. 1	Hydro	2.6	Variable
Puueo No. 2	Hydro	0.75	Variable
Waiau No. 1	Hydro	0.75	Variable
Waiau No. 2	Hydro	0.35	Variable
Puna Geothermal Venture	Geothermal	38.0	Firm
Tawhiri	Wind	20.5	Variable
Hawi Renewable	Wind	10.5	Variable
Wailuku Hydro	Hydro	12.1	Variable

Distributed Generation

Distributed generation, mostly photovoltaics, are being installed by Company customers on many of our distribution feeders. The growth of PV systems has been exponential on all of our major islands.

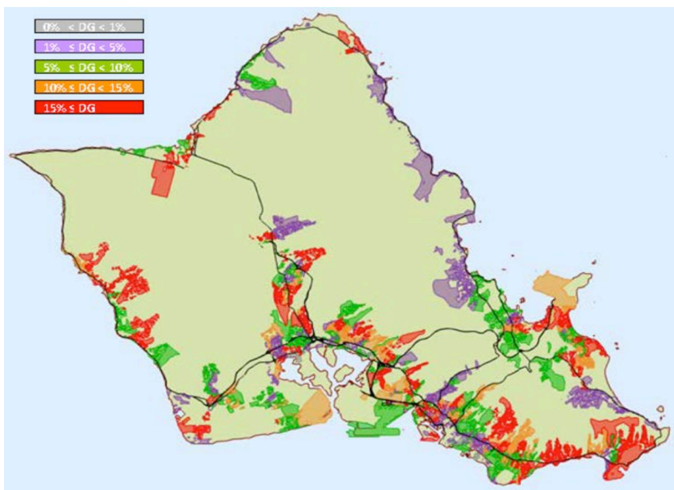
All three utilities are in the Solar Electric Power Association's top 10 PV per capita.

Hawaiian Electric Distributed Generation

Distributed generation on Oahu currently exceeds 95 MW total nameplate capacity. This is about the size of one of our mid-sized power plants.

Figure 7-6 shows the distributed generation areas on Oahu.

Figure 7-6. Distributed Generation Map of Oahu

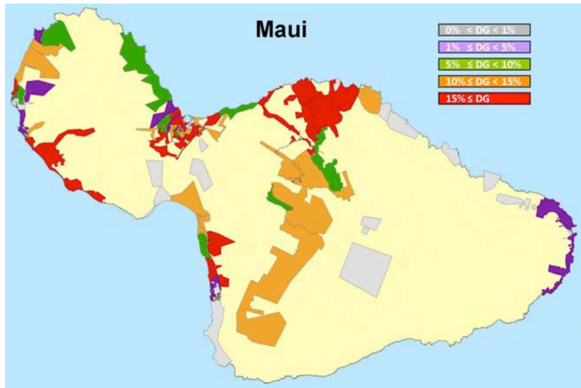


MECO Distributed Generation

Maui Distributed Generation

Figure 7-7 shows the distributed generation areas on Maui.

Figure 7-7. Maui Distributed Generation Map

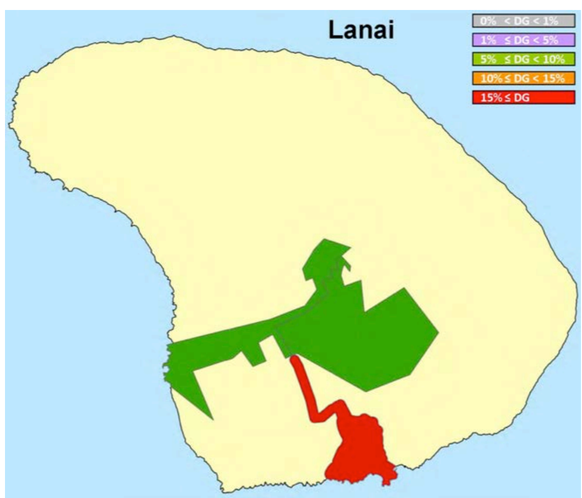


Note: This Maui Distributed Generation map is based on data from June 11, 2012.

Lanai Distributed Generation

Figure 7-8 shows the distributed generation areas on Lanai.

Figure 7-8. Lanai Distributed Generation Map

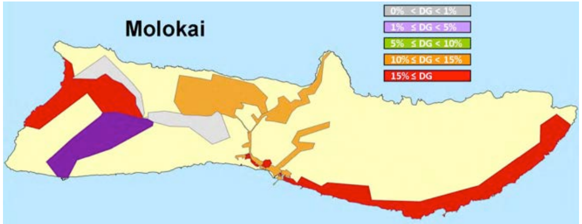


Note: This Lanai Distributed Generation map is based on data from June 11, 2012.

Molokai Distributed Generation

Figure 7-9 shows the distributed generation areas on Molokai.

Figure 7-9. Molokai Distributed Generation Map

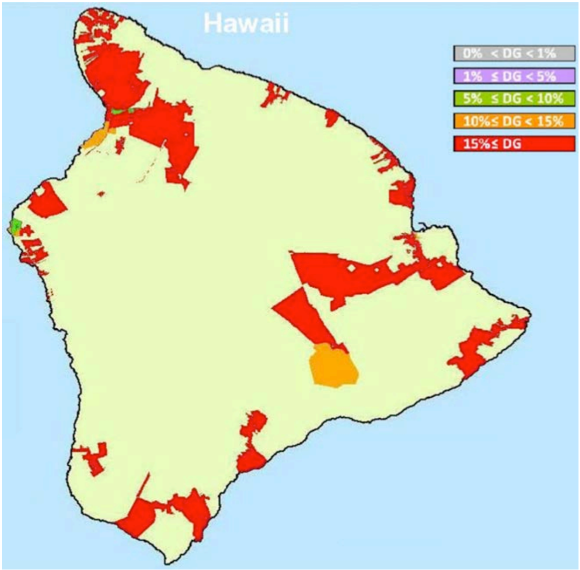


Note: This Molokai Distributed Generation map is based on data from June 11, 2012.

HELCO Distributed Generation

Figure 7-10 shows the distributed generation areas on Hawaii Island.

Figure 7-10. Island of Hawaii Distributed Generation Map



Note: This map is based on data from June 2012. Circuit data is not complete as it is still a work in progress.

Demand Response Programs

The following sections contain descriptions of the Demand Response programs for Hawaiian Electric, MECO, and HELCO.

Hawaiian Electric Residential Direct Load Control (RDLC) Program

Program Description

Hawaiian Electric's current RDLC Program was authorized in 2004 as a five-year pilot program (2005–2009) and was extended (that is, maintenance mode of operation) in 2010 for an additional three years (2010–2012). The RDLC Program allows participation from eligible residential customers with electric water heaters and/or central air-conditioning (A/C) systems. Participants in the program receive the necessary technology (that is, hardware and services) at no cost and a financial monthly incentive for program participation.

The RDLC Program offers eligible residential customers the opportunity to participate in an "interruptible load" program for water heaters (the RDLC-WH program element) and/or central A/C (the RDLC-CAC program element). Presently, Hawaiian Electric uses load control receivers (LCRs) to remotely activate load control and restore loads to the water heater and/or central A/C appliances by sending load shed commands via a wireless radio frequency paging system. As an incentive for participating in the RDLC Program, current customers receive a fixed monthly electric bill credit for participation.

The initial design of the RDLC Program was intended to provide generating unit capacity deferral benefits. In addition, the program provides valuable system reliability benefits by providing dispatch capability during grid emergencies, as well as providing system protection capability by automated load shedding during system under-frequency type events. Since 2010, the Hawaiian Electric Company has expanded the operations of the RDLC Program to provide economic dispatch to avoid or deferring the operations of certain generating units, which results in fuel savings to customers[38].

Incentive

As an incentive for participating in the RDLC Program, current customers receive a fixed monthly credit of $3.00 for electric water heaters and $5.00 for A/C participation.

[38] See *Hawaiian Electric Company, Inc. Annual Program Accomplishments and Surcharge Report, Attachment E*, filed on March 31, 2013, in Docket No. 2007-0341.

Program Impacts

Existing Program: Hawaiian Electric's RDLC Program currently has approximately 36,000 program participants who collectively contribute approximately 17 MW of system peak load reduction. Since 2010, the beginning of the maintenance mode of operations, an average of 1,000 participants or approximately 400 kW per year, have existed the program primarily due to conversion of electric water heating to solar water heating systems. In the current maintenance mode of program operations, Hawaiian Electric plans are to replace the participants who have dropped out in order to maintain the 17MW of system peak load reduction.

Expanded Program: Hawaiian Electric proposes to further enhance the value and capabilities of its traditional load management programs by examining new program technologies, program designs, and market and operational strategies for providing ancillary services support for integrating renewable resources. Hawaiian Electric is seeking to add approximately 34,000 new participants to the program over a five-year period for an additional 18 MW of system peak load reduction to attain cumulative program participation of approximately 72,000 customers with a combined system peak load reduction of approximately 36 MW. The methodology used to forecast MW totals for the RDLC Program Expansion was based on the GEP DR Potential Report that states a 30% penetration each for Direct Load Control water heater control and air conditioning controls can be expected for eligible customers.

The overall scope of the proposed expansion of the RDLC Program can be broken down into the two program elements as follows:

- Electric Resistance Water Heaters (ERWH) — The current RDLC ERWH program element has approximately 32,000 participants who contribute approximately 14 MW of peak load reduction. Gross generation unit impacts of 0.44kW per WH is based upon the March 30, 2011 KEMA EnergyScout Program Impact Report. The proposed expansion will add approximately 17,000 participants and contribute approximately 8 MW of additional peak load reduction.
- Air-conditioning (AC) element — The current RDLC central air conditioning (RDLC-CAC) program element has approximately 4,000 participants who contribute approximately 3 MW of peak load reduction. Gross generation unit impacts of 0.65 kW per AC is based upon the March 30, 2011 KEMA EnergyScout Program Impact Report The proposed expansion will modify the program eligibility requirements for air conditioning appliances and the DR enabling technology to add approximately 17,000 participants and contribute approximately 11 MW of additional peak load reduction.

For the purposes of the IRP, total impacts may be allocated as follows:

Table 7-10. RDLC Program Element

RDLC Program Element	System Benefit	% of Total Impact
RDLC ERWH	Ancillary service / capacity deferral	85%
RDLC CAC	Capacity deferral	15%

Program Budget

Existing Program: The 2013 budget for the existing extended program was submitted to the Commission in Hawaiian Electric's Annual Program Modification and Evaluation Report, filed November 30, 2012 in Docket No. 2007-0341.

Expanded Program: The budget is from 2014–2019 assumes a five-year expansion of the RDLC Program as proposed in the application (Docket No. 2012-0079), but postponed to begin in 2014. From 2020 on, the budget is the average $/kW based on 2014–2019 multiplied by the projected load reduction.

Program Data Projections

See Table F-1 through Table F-4 in *Appendix F: DR and DSM Program Data* for peak impacts and total program costs projected over the next 20 years.

Hawaiian Electric Commercial and Industrial Demand Response Portfolio

Program Description

The Hawaiian Electric Commercial and Industrial DR portfolio consists of three program elements: (1) the Direct Load Control (DLC) program element, which targets large commercial and industrial (C&I) customers, (2) the Small Business Direct Load Control (SBDLC) program element, which targets smaller C&I customers and (3) the Fast DR program element, which also targets large C&I customers. The C&I program portfolio was initially authorized in 2004 as a five-year pilot program through 2009, and in 2009, was extended for an additional three years through 2012. As of the end of the 2011 program year, the CIDLC Program has enrolled approximately 19 MW of curtailable load (approximately 18 MW from the DLC program element and approximately 1 MW from the SBDLC program element). Program participants receive financial incentive payments in exchange for allowing Hawaiian Electric the opportunity to curtail loads at the participants' facilities.

The DLC and SBDLC Programs are primarily designed to be a resource option for generation capacity deferral and emergency system protection[39].

[39] See *Hawaiian Electric Company, Inc. Annual Program Accomplishments and Surcharge Report, Attachment F*, filed on March 31, 2013, in Docket No. 2007-0341.

Since November 2011, the Hawaiian Electric Company has been piloting the design of a new Fast DR Program which is intended to be a "quick start" (that is, less than 10 minutes) resource to facilitate the grid operations when there are increasing amount of intermittent renewable energy.

Incentive

DLC participants receive a monthly financial incentive in the form of a fixed credit of $10 per kW per month ($10/kW per month) for automated load shedding or $5 per kW per month ($5/kW per month) for manually dispatched load shedding. In addition to the fixed credit incentive, participants receive a variable energy credit of $0.50 per kilowatt hour ($0.50/kWh) of reduction for each eligible kWh of energy reduction provided whenever a Dispatch curtailment event occurs.

As an incentive for participating in the SBDLC program element, participants receive a monthly electric bill credit of $5.00 for each Electric Resistance Water Heater (ERWH) unit, $5.00 per ton for central air-conditioning (CAC), and $8.00 per kW for other equipment as approved by Hawaiian Electric. If a participant is eligible to enroll multiple loads, they may do so and receive incentive payments for each enrolled load.

For the Fast DR program element, participants are offered a tiered incentive payment structure that ranges from $5/kW per month up to a maximum of $10/kW per month depending on the level of interruptible events which a customer elects to participate. In addition, the Fast DR Pilot includes a Technology Audit and Technology Incentive (TA/TI) incentive funding mechanism which ranges from $300/kW for semi-auto load control to $600/kW for automated load control.

Program Impacts

Existing Program: Hawaiian Electric's C&I DR portfolio currently has 203 total participants comprised of 42 "active" large business customers participating in the DLC program element, 161 small business customers participating in the SBDLC program element, and 8 customers participating in the Fast DR program. The total interruptible load available from the active participants in both program elements is approximately 19 MW. The impact increases to 22 MW in 2013 due to the planned replacement of DLC customers who did not complete the final commissioning process and the addition of the Fast DR program participants. The achieved load impacts will continue to be used to defer future capacity additions for generation units planned for potential construction. In addition, the program provides valuable system reliability benefits through load curtailment capability during (or to prevent) grid emergencies, as well as providing system protection capability by load shedding during system under frequency curtailment events.

Expanded Program: Hawaiian Electric is seeking to programmatically enroll an additional 3 MW of curtailable load through the expansion of the SBDLC Program for a cumulative CIDLC Program total of approximately 25

MW (an estimated 21 MW contribution from the combined merger of the DLC and Fast DR program elements and an estimated 4 MW contribution from the SBDLC program element). The Proposed Expansion will result in a cumulative enrollment of approximately 900 CIDLC Program participants to achieve the proposed load reduction goal of approximately 25 MW. The projected load reduction beyond the initial three-year SBDLC expansion is based on the Realistic Achievable Potential (RAP) market estimate that was set forth in a report produced by Global Energy Partners, Inc. (GEP) titled *Assessment of Demand Response Potential for Hawaiian Electric, HELCO, and MECO* (the "GEP DR Potential Report"), Table ES-5, pg. xi. The combined projected Peak Load Reduction (MW – Customer Level) of the "C&I Direct Load Control" and "C&I-Curtailable" categories in 2020, 2030 and 2040 were assumed. The projected load for the years spanning between 2020, 2030 and 2040 was extrapolated.

For the purposes of the IRP, total impacts may be allocated as follows:

Table 7-11. CIDLC Program Element

CIDLC Program Element	System Benefit	% of Total Impact
DLC: Dispatch only	Capacity deferral	45%
DLC/Fast DR: Dispatch & UF	Ancillary service/capacity deferral	50%
DLC: Dispatch & UF	Ancillary service/capacity deferral	50%
SBDLC: Dispatch & UF	Ancillary service/capacity deferral	5%

Program Budget

Existing Program: The 2013 budget for the existing extended program was submitted to the Commission in Hawaiian Electric's Annual Program Modification and Evaluation Report, filed November 30, 2012, in Docket No. 2007-0341.

Expanded Program: The budget from 2014–2016 assumes a three-year expansion of the SBDLC Program as proposed in the expansion application (Docket No. 2012-0118), but postponed to begin in 2014. For 2017 and forward, the budget is based on the average $/kW of 2014–2016 multiplied by the projected load reduction. The budget from 2014–2016, also extends, rather than expands, the DLC program element to allow for the completion of the Fast DR Pilot and ultimate modification of the DLC program element to provide for the addition of the new Fast DR program design in the C&I DR portfolio.

Program Data Projections

See Table F-5 and Table F-6 in *Appendix F: DR and DSM Program Data* for peak impacts and total program costs projected over the next 20 years.

Hawaiian Electric Commercial and Industrial Dynamic Pricing (CIDP) Pilot Program

Program Description

Under the two-year CIDP Pilot program the demand charge will be reduced for commercial and industrial program participants who lower their energy use at certain times (and sometimes on short notice) when necessary to fulfill the Company's operating reserve requirement, meet system demands, or otherwise reduce operating costs. The Company is targeting total load reductions of 2 MW and a minimum of 20 participants in the CIDP Pilot program. As of December 1, 2012, this program has not received Commission approval.

A participant would agree to reduce facility demand to an agreed-upon firm service level (FSL, expressed in kW) when a curtailment event is called. In return, the participant receives a reduced demand charge (that is, a monthly $/kW credit), for each kW of demand difference between the participant's actual demand and the FSL regardless of whether or not a curtailment event is called. However, when an event is called, the participant is expected to reduce facility load to, or below, the FSL.

During a curtailment event, the participant may choose to reduce load to a level above the FSL, or not reduce load at all. In that circumstance, the participant will pay a "buy-through" energy price in $/kilowatt hour (kWh), that is in effect only for the duration of the curtailment event, for all kWh consumed above the FSL. The buy-through energy price is several times higher than the otherwise applicable tariff.

The amount of the credit received under the program will depend upon a number of factors including:

- The extent of advance notice provided to participants to reduce loads down to their FSL (that is, 10-minute, one-hour, or day-ahead);
- The hours during the week in which they agree to be available to reduce loads;
- The maximum number of hours per year during which they will reduce loads; and
- The difference between their FSL and their actual demand.

The demand credits and buy-through energy price affect the Company's revenue and are not considered program costs in the program budget described below.

To achieve the operational requirements associated with the program, participants may be required to invest in physical equipment needed to schedule and control loads either on command by the system operator (Auto DR) or on command by the facility management staff (Semi-automated DR) following notification by the system operator. To overcome customer resistance to make investments, Hawaiian Electric will provide one-time Technology Incentives (TI) of up to $600/kW.

Program Impacts

This program has not yet been implemented; thus, there is little basis for estimating the proportion of program impacts among the 10-minute, one-hour, and day-ahead advance notification options. For the purposes of the IRP, total impacts may be allocated as follows:

Table 7-12. Notification Impact

Notification	System Benefit	% of Total Impact
10-Minute	Ancillary service/capacity deferral	50%
One-Hour	Capacity deferral	25%
Day-Ahead	Capacity deferral	25%

Existing Program. The program application was filed in December 2011. The program impacts assume that the program will be approved by the Commission for implementation beginning in 2013 through 2014. The annual program impacts are the same as proposed in the program application.

Expanded Program. The expanded program impacts assume that the realistic achievable potential (RAP) as estimated in the May 2010 *Assessment of Demand Response Potential for HECO, HELCO, and MECO, Final Report*, by Global Energy Partners, LLC (GEP DR Assessment) is achieved in 2015 and every fifth year thereafter, through 2040. The estimated impacts between each fifth year are linearly interpolated.

Program Budget

Existing Program. The budget is the same as proposed in the application to the Commission for the two-year pilot.

Expanded Program. Following the first two years for the pilot, customer incentives are continued at $600 per incremental kW impact. Other program and evaluation costs are the average of the two-year (2013–2014) costs for the pilot program.

Program Data Projections

See Table F-7 through Table F-9 in *Appendix F: DR and DSM Program Data* for peak impacts and total program costs projected over the next 20 years.

MECO Demand Response (DR) Programs

MECO recognizes that DR could play a significant role in meeting Maui's electric system operational objectives. While DR may not always lower cost or increase renewable energy usage, DR options have the potential to create value for Maui customers and should be investigated. Accordingly, MECO will continue to aggressively pursue DR as a potential cost-effective alternative to:

- Potentially delay the addition or reduce the size of new generation, and/or
- Potentially provide regulating reserve and reduce the use of existing conventional generation to lower costs.

The Residential Direct Load Control (RDLC) and Commercial and Industrial Direct Load Control (CIDLC) pilot programs described in this section were based on assumptions of program design characteristics. MECO will work collaboratively with DR service provider(s), selected through a formal RFP process, on the final program design of its pilot programs, which may differ from these assumptions.

MECO's current and future DR efforts are detailed in the Maui Action Plan which can be found in Chapter 22.

MECO Residential Direct Load Control (RDLC) Pilot Program

Program Description

Residential customers on the island of Maui may have the opportunity to participate in a proposed pilot program that could allow the utility to interrupt the operation of their electric water heater and/or to increase the thermostat temperature of their central air conditioning (A/C) systems in return for a monthly incentive.

The proposed program is based on a two-way communication technology that utilizes the customer's broadband access, maintained at their own cost, to send and receive signals from the control device on the enrolled appliance to a service provider's load control software platform.

The proposed RDLC communication technology will allow for participant notification of load control events. However, little or no advance notice would be provided when the DLC resource is used as a tool to maintain system stability, as this type of event would likely occur with little notice to the Company.

Program Impacts

Over the twenty year planning horizon, preliminary planning estimates project that MECO may be able to enroll over 16,000 residential participants in the program with approximately 7.5 MW of capacity available for interruption. No change in energy consumption is expected to be observed, as most participants will likely still use the same amount of hot water, and for A/C, will either pre-cool or post-cool their homes to the desired comfort level.

The projected participation assumes that 50% of customers with eligible central A/C units will also have eligible electric water heaters and they would be incentivized to enroll both appliances in the pilot program.

The estimated kW impact per measure is based on the results of Hawaiian Electric Company's RDLC program impact evaluation.

Program Budget

The budget reflects cost estimates for MECO to provide overall responsibility for program management, including program marketing and enrollment, execution and administration of agreements with participating customers, making monthly participant incentive payments, calling RDLC events, conducting program evaluations, and providing regulatory reporting. The budget assumes that MECO will work collaboratively with a service provider selected through a competitive bidding process to provide implementation services for the program (equipment, installation, installation scheduling, hosted direct load control network operations services). The service provider would coordinate with individual customers to arrange equipment installation and setup at customers' sites, and will also be responsible for maintenance of the equipment required for participation in the program and providing customer support.

Program Data Projections

See Table F-10 and Table F-11 in *Appendix F: DR and DSM Program Data* for peak impacts and total program costs projected over the next 20 years.

MECO Commercial & Industrial Direct Load Control (CIDLC) Pilot Program

Program Description

Commercial and industrial customers on the island of Maui who meet the minimum eligibility requirements may have the opportunity to participate in a proposed pilot program to allow MECO to call load control events to reduce energy demand on the system. Enrolled commercial and industrial customers may nominate all or a portion of their electrical load to participate in the CIDLC Pilot Program (Controlled Load). In order to participate, each participant must have broadband access. Customers on load management Riders M and T will also be permitted to participate in the program, provided they meet the eligibility requirements.

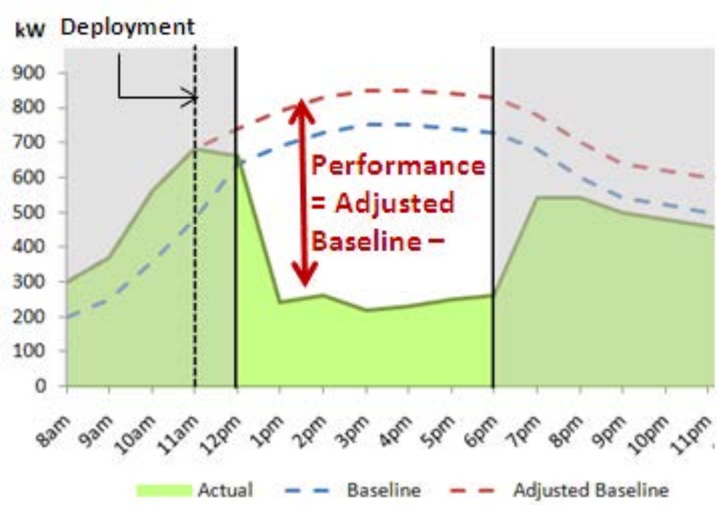
Controlled Loads may be interrupted automatically by MECO, or manually by the participant, and participants will receive incentives to allow these interruptions. Participants will receive a Load Control Event notification prior to each Load Control Event. This may allow participants to interrupt their Controlled Loads: a) automatically (utilizing a remotely operated relay switch); b) through a Building Management System (BMS); c) manually; or d) through a combination of these options.

CIDLC participants may be eligible to receive a controlled demand incentive (CDI) credit on their electric service bill in exchange for allowing MECO to curtail their energy usage during load control events. CIDLC Program participants designate all or a portion of their load to be controlled. The CDI will be paid monthly for the amount of capacity that the participant nominates as Controlled Load. The monthly CDI will be paid whether or not MECO actually utilizes the Controlled Load during the month.

In addition to the CDI, participants may receive an Energy Reduction Incentive (ERI) per kilowatt hour of energy reduction provided whenever a Dispatch curtailment event occurs and lasts for more than one hour. A "similar day" baseline along with a "day-of- event" adjustment (to accurately reflect the energy usage during that day) will be used to determine the amount of energy reduced during a Load Control Event.

The baseline is the Profile Baseline, which uses recent historical interval meter data to predict a facility's event day usage. A Baseline Adjustment is also calculated to more accurately reflect the load conditions of the event day. This adjustment is based on average load during the two hours preceding deployment.

Figure 7-11. Profile Baseline and Adjustment



A High 8 of 10 profile baseline considers the 10 most recent days preceding a Controlled Load Event and uses data from the 8 days with the highest load within those 10 days to calculate the baseline. Holidays, weekends, and previous event days are excluded since they are not accurate representations of a customer's normal energy usage.

Program Impacts

MECO proposes to implement the proposed CIDLC Program on the island of Maui to acquire 3.3 MW gross generation of commercial and industrial customer load reductions on the grid by the end of the twenty year planning horizon.

Program Budget

The budget reflects cost estimates for MECO to manage the overall responsibilities relating to program participants including execution and administration of program agreements with participating customers, program marketing, evaluating customer interest and participation, equipment allowances, coordination and execution of Load Control Events, and providing monthly participant incentives. The budget assumes that MECO will work collaboratively with a service provider selected through a competitive bidding process. The service provider will provide project management and implementation services such as equipment, installation, hosted direct load control network operations services, maintenance of the equipment required for participating in the program, and customer support including creating baseline calculations for each participant.

Program Data Projections

See Table F-12 in *Appendix F: DR and DSM Program Data* for peak impacts and total program costs projected over the next 20 years.

MECO Fast Demand Response Pilot Program

Program Description

The Fast Demand Response (Fast DR) Pilot Program, approved on November 9, 2011, Docket 2010-0165, is designed to be a quick response (less than 10 minutes) resource. The Fast DR Pilot Program is comprised of two phases or elements which are the Semi-Automated DR and Automated DR.

Generally, in the semi-automated DR process, a service provider's operations center will be notified of an event via a phone call or as an auto-generated phone message. The service provider will notify the program participants to perform according to their pre-defined curtailment plan.

The automated DR process differs from the semi-automated process in that the curtailment according to the customer's pre-defined curtailment plan is executed automatically by utilizing a customer's energy management system without requiring acknowledgement from the customer, as opposed to the semi-automated process which may require an acknowledgment by phone or email from the customers' facility personnel.

Service interruptions under the Fast DR Program cannot exceed two hours per day and a maximum of 80 hours per year per participant.

MECO proposes to maintain an enrollment of four participants in the semi-automated option similar to the pilot program.

The CDI is$10/kW/month. The ERI is $0.50/kWh/month but is not paid for the first 15 hours of curtailment.

Program Impacts

The impacts from the four participants are projected to remain at 200 kW.

Program Budget

The budget assumes that the program will continue to have four participants throughout the planning horizon.

Program Data Projections

See Table F-13 *Appendix F: DR and DSM Program Data* for peak impacts and total program costs projected over the next 20 years.

HELCO Demand Response Programs

HELCO currently does not have customer DR programs, but has successfully utilized under-frequency load-shedding (UFLS) for many years as a very low-cost but effective DR resource. HELCO also obtains peak shifting from load management through its available tariffs.

However, as DR may offer cost-effective system benefits, HELCO has been taking steps to implement its DR strategy incrementally, over time, through a combination of shorter-term initiatives including pilot programs, participation in research, development and demonstration (RD&D) projects, and market studies. Currently, HELCO is in the process of studying and conceptualizing various aspects of a suite of demand-side programs as well as monitoring the progress of similar programs and RD&D projects at Hawaiian Electric and MECO. These efforts will assist HELCO in defining the applicability of the various demand response options to HELCO's system and the specific program mix to be included in the programs which may eventually be implemented on the island of Hawaii. HELCO's actions, as described in greater detail in the HELCO Action Plan, will be framed in terms of a demand response roadmap (DR Roadmap). Refer to the Demand Response section of *Chapter 21: HELCO Action Plan* for more information on HELCO's "DR Roadmap".

For IRP modeling purposes, potential future programs with associated costs and benefits were based on MECO's program projections for a:

- Residential Direct Load Control (RDLC) Program: See Table F-14 and Table F-15 in *Appendix F: DR and DSM Program Data* for peak impacts and total program costs projected over the next 20 years.
- Commercial and Industrial Direct Load Control (CIDLC) Program: See Table F-16 in *Appendix F: DR and DSM Program Data* for peak impacts and total program costs projected over the next 20 years.
- Fast Demand Response Program: See Table F-17 in *Appendix F: DR and DSM Program Data* for peak impacts and total program costs projected over the next 20 years.

PBFA Demand-Side Management (DSM) Programs

There are three levels of Demand-Side Management (DSM) Programs under the control of the Public Benefits Fee Administrator (PBFA) for Hawaiian Electric, MECO, and HELCO. These DSM programs represent contribution from all of the PBFA's DSM programs at different achievement levels of the energy targets set by the Energy Efficiency Portfolio Standards (EEPS) law.

Efficiency measures include a range of programs and activities such as traditional incentive-based programs, education and outreach, implementation of building codes and appliance and equipment standards, system upgrades, and efforts designed to address the market barriers to energy efficiency.

The EEPS Evaluation Measurement & Verification Contractor (EM&V Contractor) and the Public Benefits Fee Administrator (PBFA) provided the Companies a base forecast of the total annual EEPS impacts and allocated those impacts to the Companies by island. The Hawaiian Electric Companies have assumed for the purposes of this IRP that all of the EM&V's and PBFA's EEPS base forecast would be attributed to the Companies since no allocation has been made to other contributing entities such as the Kauai Island Utility Cooperative (KIUC). The total EEPS forecast provided to the Companies included energy and peak demand savings impacts associated with contributions from Commission's regulated entities and non-regulated entities. The contribution to the EEPS associated with the regulated entities primarily includes the DSM programs administered by the PBFA. The contribution to the EEPS associated with the non-regulated entities, the non-PBFA EEPS contribution, includes energy savings from building codes, new appliance standards, and Federal and State Government energy savings mandates that are forecasted to occur in outside of the PBFA DSM programs.

The Companies then aligned the different levels of EEPS impacts to correspond to each scenario which are reflected in Table 6-1. Summary Table Quantifying the Scenarios (page 6-13). Each scenario's EEPS impacts were developed by adjusting EM&V's and PBFA's EEPS base forecast to the scenario's level. The Non-PBFA EEPS Contribution and PBFA DSM Programs contributions were both adjusted to obtain EEPS impacts that exceeded the base forecast (110% of base EEPS forecast), achieved the base forecast (100% of base EEPS forecast), or partially achieved the base forecast (75% of base EEPS forecast) and are summarized in Table F-18 through Table F-32 in *Appendix F: DR and DSM Program Data*.

Supply-Side Resource Options

In the context of IRP, supply-side means resources designed to supply power into the utility system. This section discusses the following 2013 IRP supply-side resources activities:

- Unit information form development
- Future capital cost for renewable energy options
- Bus bar unit information cost chart

Unit Information Form (UIF) Development

The Hawaiian Electric Companies contracted Black & Veatch (B&V) to develop unit information forms (UIF) for supply-side resource options (SRO) to support the Revised Framework. In general, the SRO UIFs are generic and not project-specific. Data used to develop the SROs are based on previous IRPs for Hawaiian Electric, HELCO, and MECO so unit sizes and ratings are consistent with the system requirements for each utility.

The following technologies were evaluated as part of 2013 IRP:

- Large Turbine Onshore Wind (30 and 10 megawatt [MW] blocks, 2.3 MW turbines)
- Small Scale Onshore Wind (600 kW turbines, phased development up to 6 MW)
- Offshore Wind (100 MW blocks)
- Solar Photovoltaic (PV):
- Residential (2 kilowatts [kW])
- Large Rooftop (100 kW)
- Ground Mounted (1 MW blocks)
- Solar Thermal (Trough, 50 MW)
- Geothermal (new and existing sites [25 MW])
- Ocean Wave (2016 [750 kW] and 2020 [15 MW] systems)
- Ocean Thermal Energy Conversion (OTEC) (10 MW)
- Biomass Combustion (Banagrass, 25 MW)
- Biomass Conversion at Puna Generating Station (Eucalyptus, 13 MW)
- Waste-to-Energy (WTE) (municipal solid waste [MSW] mass burn, 8 MW)
- Fuel Cell (phosphoric acid using natural gas fuel, 400 kW)

- Battery Energy Storage:

Daily Peaking (10 MW:90 minute discharge duration)
- Spinning Reserve (25 MW:30 minute discharge duration)
- Frequency Regulation (25 MW:15 minute discharge duration)

Reciprocating Engines, Biodiesel:
- 1x0 Wartsila 18V46 (16.7 MW)
- 1x0 Wartsila 12V32 (5 MW)
- 6x0 Wartsila 18V46 (100.2 MW)

Simple Cycle Combustion Turbines, Biodiesel:
- 1x0 GE LM2500 (21.1 MW)
- 1x0 GE LM6000 (41.9 MW)
- 1x0 GE LMS100 PA (90.8 MW)

Combined Cycle Combustion Turbines, Biodiesel:
- 2x1 GE LM2500 (63.2 MW)
- 1x1 GE LM6000 PG (58.8 MW)

Simple Cycle Combustion Turbines, Natural Gas:
- 1x1 GE LM6000 PG (58.3 MW)
- 1x0 GE LMS100 PA (95.2 MW)

For the majority of the UIFs, the base capital cost estimates assumes insurance and freight of all equipment at a typical mainland US facility. No sales tax or excise tax was included in the base estimate. Labor was assumed to be based on mainland rates. Cost estimates are based on Black & Veatch experience, fixed price contracts, and publicly available information. Adjustment factors specific to Hawaii were applied to the base capital cost estimates for shipping, local commodity pricing, taxes, and labor wage rates and productivity.

Nonfuel operations and maintenance (O&M) costs were developed to include two components: fixed and variable O&M. As with capital costs, O&M costs were typically developed for mainland US projects, then adjusted in a similar fashion to reflect Hawaii-specific costs.

The UIFs and notes that accompany the UIFs were the main deliverables provided to Hawaiian Electric in the development of the supply-side data by Black & Veatch. Five tables summarize the salient performance and cost attributes of the technologies evaluated in support of 2013 IRP. These five tables are:

- Table 3-1. Capital Cost Summary
- Table 3-2. O&M Cost Summary
- Table 3-3. Technical Performance and Availability Summary
- Table 3-4. Environmental Performance Summary
- Table 3-5. Schedule and Resource Requirement Summary

See also the UIF (on page K-69) and note page for large turbine onshore class 7 wind (on page K-71), as well as the entire Black & Veatch report in *Appendix K: Supply-Side Resources*.

Future Capital Cost for Renewable Energy Options Memorandum

As part of the 2013 IRP effort, Black & Veatch provided the capital and operating cost data for the Unit Information Forms (UIFs) development. Future changes in nominal technology costs have been estimated by Hawaiian Electric as entries into the scenario planning (Strategist model) efforts. Members of the Advisory Group (AG) have questioned some of the future cost assumptions made by Hawaiian Electric, with constant dollar cost estimates from National Renewable Energy Laboratory (NREL, year 2000) presented by the AG that show future cost declines.

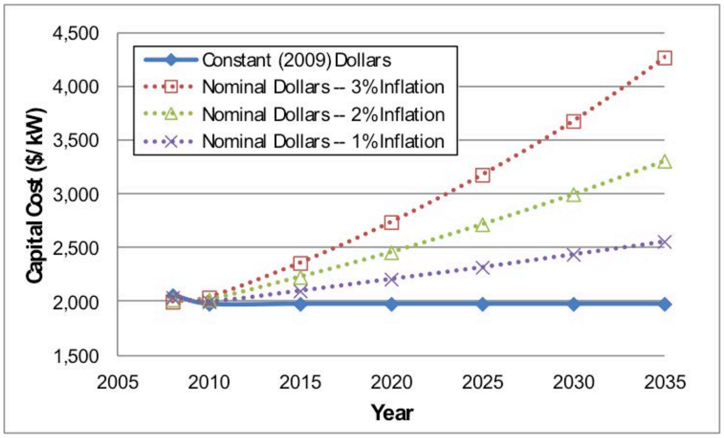
When comparing costs over broad periods of time, variations are based in part on inflation and the corresponding change in the purchasing power of the dollar. Therefore, to understand variations due only to technology changes independent of inflation, costs are converted from nominal (or current) dollar values to real (or constant) dollar values. Nominal and real dollar values are defined as follows:

- **Nominal (or Current) Dollar Value** – the actual (unadjusted) dollar amount of money spent or earned within a given period of time.
- **Real (or Constant) Dollar Value** – value of money spent or earned within a given period of time, adjusted to remove the effects of price changes (that is, inflation). Real Dollar Value represents the value of money spent or earned, assuming the dollar had constant purchasing power over the given time period.

Black & Veatch reviewed the AG data and compared it to recent cost NREL estimates (this work was performed by Black & Veatch in 2012 under contract to NREL for the purpose of updating NREL's estimates). For renewable technologies, Black & Veatch projected that capital costs for certain technologies would remain flat (in constant 2009 dollars), while capital costs for other technologies would decrease (in constant 2009 dollars). Renewable technologies for which capital costs are projected to remain relatively flat included the following: biomass, geothermal, onshore wind and combustion turbine technologies.

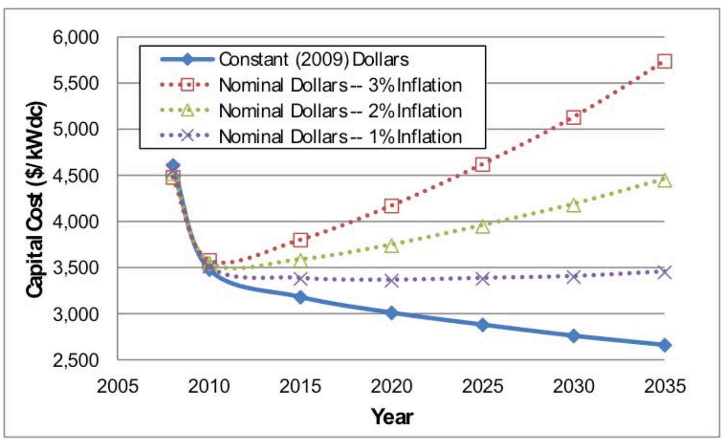
As an example, capital costs for onshore wind projects (in both constant 2009 dollars and nominal dollars) are shown in Figure 7-12. Estimates of nominal-dollar costs are shown with general inflation rates ranging from 1 to 3 percent. While costs in 2009 dollars remain flat, costs in nominal dollars increase over the period from 2008 to 2035. If no technological improvements occur, the extent to which nominal dollar costs increase over this time period is largely dependent upon the inflation rate experienced during this time.

Figure 7-12. Projected Future Cost Trends for Onshore Wind Technologies



Black & Veatch also reported renewable technologies for which capital costs (in constant 2009 dollars) are projected to decrease to some extent including solar PV, solar thermal, off-shore wind, and battery energy storage. As an example of expected cost trend for these technologies, capital costs for large, utility-scale, fixed tilt solar PV projects (in both constant 2009 dollars and nominal dollars, assuming three different levels of inflation) are shown in Figure 7-13. While costs in constant 2009 dollars decrease over the period from 2008 to 2035, the costs in nominal dollars increase over the same period. Again, the extent to which nominal dollar costs increase is dependent upon the inflation rate used during the time period.

Figure 7-13. Projected Future Cost Trends for Fixed Tilt Solar PV Technologies



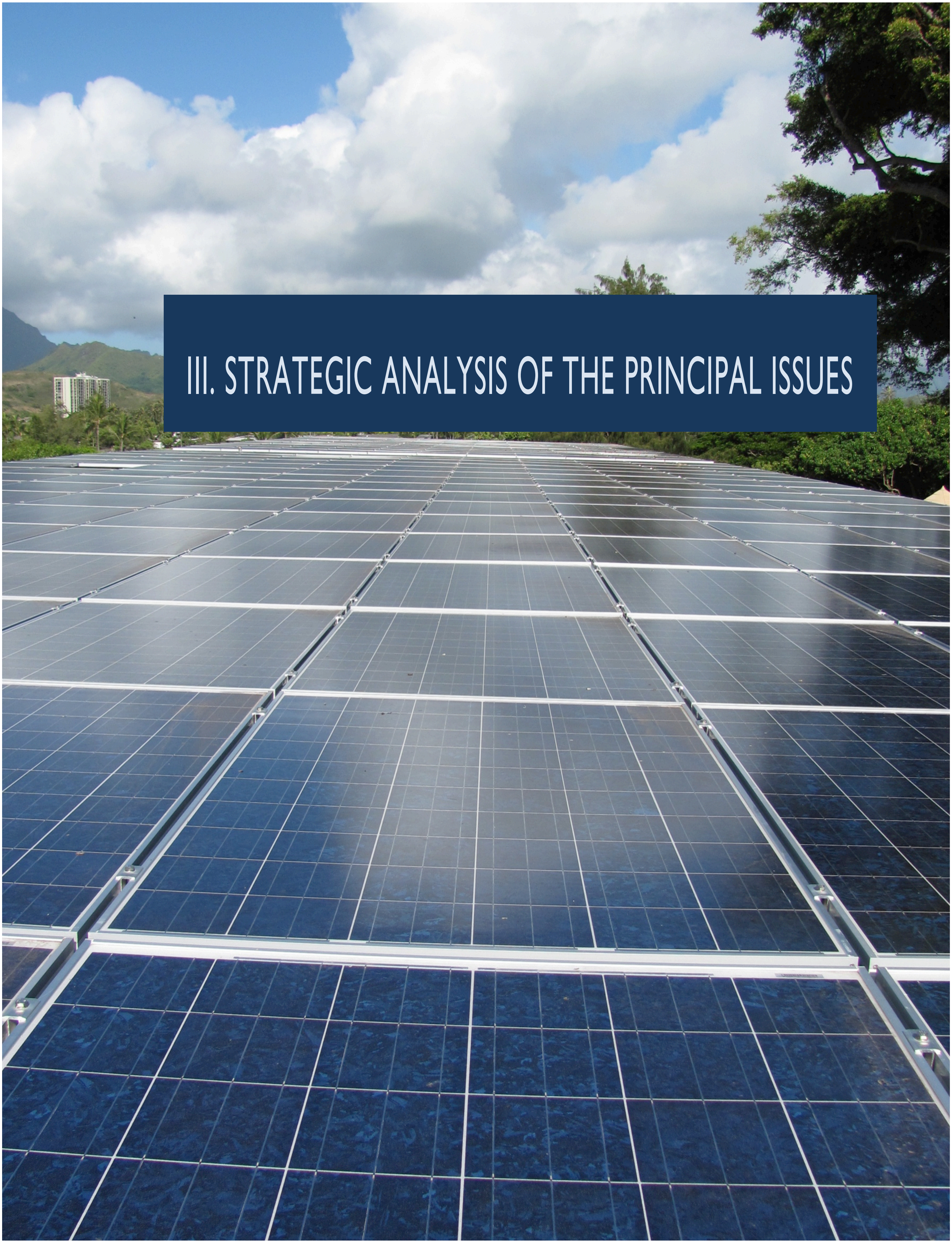
Thus, the future cost assumptions made by Hawaiian Electric in the Strategist model was appropriate.

Bus Bar Cost Analysis

Bus bar costs or levelized cost (cost per kilowatt hour) is the cost of producing electricity. This bus bar cost includes the cost of capital, debt service, maintenance and fuel up to the power plant bus or bus bar (point beyond the generator but prior to voltage transformation point in the plant switchyard). Such cost is computed using cash flows throughout the facility's life cycle and includes initial expenses (design, licensing, installation), operating expenses, maintenance expenses, taxes, and decommissioning expenses.

Appendix K contains summary tables and charts (as a function of capacity factors) for 2015, 2020, and 2030; and the worksheets of each supply-side UIF technology. These bus bar were used in cost projections for the Stuck in the Middle and Blazing a Bold Frontier scenarios.

III. STRATEGIC ANALYSIS OF THE PRINCIPAL ISSUES



Addressing Each Principal Issue

Throughout our analysis, the Companies have focused on addressing the Principal Issues as directed by the Commission. The following is a cross reference to the chapters and appendices where a primary discussion of each Principal Issue can be found.

The Principal Issues can be found in *Chapter 4: Principal Issues to Address*. The exact order can be found in *Appendix C: Commission Documents*.

Addressing the Legislative Issues

The Legislature directed the Commission to consider five issues in the IRP analysis.

1. Replace Existing Fossil Fuel Generating Plants

Chapter 8: Resource Planning and Analysis under various Scenarios

Chapter 9: Environmental Regulation Compliance in the "Complying with Environmental Standards" section

- *Chapter 15: Assessing the Capacity Value of Wind*

2. Inter-Island Connectivity

Chapter 11: Inter-Island and Inter-Utility Connection Analysis

- *Appendix H: Inter-Island Transmission Costs*

3. Geothermal Resources

- *Chapter 8: Resource Planning and Analysis* in the "Replacing Fossil Fuel Plants with Renewable Energy Resources" section

Chapter 9: Environmental Regulation Compliance in the "Complying with Environmental Standards" section

- *Chapter 11: Inter-Island and Inter-Utility Connection Analysis*

4. Energy Storage

- *Chapter 8: Resource Planning and Analysis* in the "Replacing Fossil Fuel Plants with Renewable Energy Resources" and "Battery Storage Analysis" sections

5. Waste-to-Energy Facilities

- *Chapter 8: Resource Planning and Analysis* in the "Replacing Fossil Fuel Plants with Renewable Energy Resources" section

Addressing the Commission Issues

The Commission identified 12 issues, in both its current dockets as well as in past dockets, that the Companies must address.

6. Best Use of Hawaiian Electric CIP CT-1 Generating Facility

- *Chapter 10: CIP CT-1 Generating Station Analysis*

7. Reasonable Cost and Rate Impacts

- *Chapter 19: Action Plans*

8. RPS Rate Impact

- *Chapter 8: Resource Planning and Analysis* in the "RPS Rate Impact" section

9. EEPS Rate Impact

- *Chapter 8: Resource Planning and Analysis* in the "EEPS Rate Impact" section

10. Captive Customer Rate Impact

- *Chapter 19: Action Plans*

11. Inter-Island and Inter-Utility System Transmission

Chapter 11: Inter-Island and Inter-Utility Connection Analysis

- *Appendix H: Inter-Island Transmission Costs*

12. Smart Grid Implementation

- *Chapter 12: Smart Grid Implementation Analysis*

13. Environmental Regulation Compliance

- *Chapter 9: Environmental Regulation Compliance*

14. Fuel Supply and Infrastructure

- *Chapter 8: Resource Planning and Analysis* in the "Fuel Supply and Infrastructure Analysis" section

15. Fossil Fuel Generation Resources

Chapter 8: Resource Planning and Analysis in the "Fuel Supply and Infrastructure Analysis" section and in various Scenarios

- *Chapter 9: Environmental Regulation Compliance* in the "Complying with Environmental Standards" section

16. Essential Grid Ancillary Services

- *Chapter 13: Essential Grid Ancillary Services Analysis*

17. Transmission Planning Analysis

- *Chapter 14: Transmission Planning Analysis*

Chapter 8: Resource Planning and Analysis

Fully developing robust action plans require analysis of the myriad factors that comprise the complex and delicate balance required to operate a safe, reliable electricity grid — lots of analysis. To conduct this analysis as well as address the many principal issues required of this IRP process, the Companies employed a state-of-the-art software developed specifically for resource planning — Strategist — and, to a lesser extent, the most widely run spreadsheet software — Excel.

The chapter details much of our analysis conducted in such key areas as energy storage, demand response, fuel supply, energy efficiency, and resource portfolio standards.

Capacity Planning Criteria

Hawaiian Electric Capacity Planning Criteria

Complying with Hawaiian Electric's capacity planning criteria is critical to maintaining an adequate amount of capacity and reliable operation of the Hawaiian Electric generating system. All future resource plans, regardless of scenario, were developed to satisfy the load service capability (Rule 1) and quick load pickup criteria (Rule 2), the reliability guideline, and the spinning reserve requirements at a minimum. Hawaiian Electric's current reliability guideline of 4.5 years per day was applied in computer simulations in addition to the Rule 1 criteria using the Strategist model to determine the appropriate timing of supply-side resource additions. Hawaiian Electric's current capacity planning criteria can be found in *Appendix L: Capacity Planning Criteria*, which was a study conducted to validate Hawaiian Electric's capacity planning criteria in Hawaiian Electric IRP-3.

Maui Electric Company and Hawaii Electric Light Company

HELCO and MECO's Maui Division uses a similar form of Rule 1. MECO's Molokai Division and Lanai Division use similar but less stringent Rule 1 criteria. HELCO and MECO do not have a Rule 2 criteria, instead relying more heavily on quicker starting generating units and load shed capabilities to restore frequency.

HELCO and MECO use the following capacity planning criteria to determine the timing of an additional generating unit:

- 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 ratings of all units minus the rating of the largest available unit minus the ratings of any units on maintenance must be equal to or greater than the system peak load to be supplied.
- Maintaining a reserve margin of approximately 20 percent will be considered.

Considerations in Determining the Timing of Unit Additions

The need for new generation is not based solely on applying this criteria. As capacity needs become imminent, it is essential that additional consideration is allocated to ensure timely installation of generation capacity necessary to meet customers' energy needs. As stated in the MECO 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 might 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 costs.
- The forecasted minimum demand.
- Required power purchase obligations and contract terminations.
- The unpredictable output of supplemental resources.
- The uncertainties surrounding non-utility generation resources.
- Transmission system considerations.
- Meeting environmental compliance standards.
- System stability considerations for isolated island systems.

Hawaiian Electric Spinning Reserve

Spinning reserve is the amount of reserve capacity that is immediately available from units that are connected to the system and are operating below their maximum rated levels. The purpose of Hawaiian Electric's spinning reserve requirement is to avoid customer disruptions caused by the sudden loss of the largest generating unit operating on the grid (such as AES).

In actual operation, the spinning reserve level carried on the system is a function of the load on the system, the generating units serving the system, and the load on the unit carrying the largest amount of the system load. Strategist is not designed to model this level of sophistication; it allows only a single input for this variable. As a result, 180 MW, which represents the largest generating unit on Hawaiian Electric's system, is used to model spinning reserve requirements. As large amounts of variable, as-available generation are added to the system, additional upward regulating reserve, beyond the spinning reserve, might be required to cover for the sub-hourly variability of the as-available generation to quickly offset the changes in the variable generator's output (for example, wind farms). This additional regulating generation can be ramped either up or down to cover the potential variation in wind farm output. The greater the capacity of wind farms that are online, the larger the potential variation in wind farm output and the larger the required amount of regulating reserves. Because the spinning reserve requirement needs to be entered into the Strategist model before resources are added, any changes to the spinning reserve value need to be made after resource plans are developed

Regulating or Operating Reserve

MECO Maui Division

Regulating or operating reserves are a combination of spinning and non-spinning resources that cover the variability in wind and solar resources. For MECO's Maui Division, the spinning and regulating reserves are pooled together with a minimum level of 6 MW to cover both contingencies (such as the loss of a generating unit) and for variability of wind and solar resources. Regulating reserve requirements for Maui increase based on the amount of total wind power delivered to MECO as follows: 50% of the first 30 MW of delivered wind power, and 100% of each MW of delivered wind power above 30 MW up to 50 MW.

Thus:

- If wind power is less than 30 MW, the upward reserve requirement is one-half the delivered wind power or 6 MW, whichever is greater.
- If delivered wind power is greater than 30 MW, the upward reserve requirement is 15 MW plus 1 MW for each MW of delivered wind power above 30 MW up to 50 MW.

In the Strategist model, the Companies used 40 MW to represent the regulating reserve requirement.

HELCO Regulating Reserve

The amount of upward regulating reserve HELCO carries on the grid is a function of the output of all of the as-available resources on the grid and the extent to which their output is fluctuating. When there is lower as-available output, HELCO can carry lower amounts of regulating reserve, but generally not less than 6 MW of upward regulating reserve. This amount is sufficient to serve as a buffer for typical fluctuations in demand on the grid. As as-available output increases, HELCO must carry an increasing amount of up regulating reserve. This is because the firm capacity generating units must be ready to ramp up their outputs in the event the output from the wind resources suddenly and unexpectedly decline. The higher the output of the as-available resources, the more regulating reserve that must be carried to make up for potentially greater losses in output from the wind resources.

In 2012 and 2013, HELCO carried an average of 17 MW of upward regulating reserve including 1.2 MW of reserve capacity from the difference between the economic dispatch and maximum ratings of three units. In the Strategist model, the system was modeled with a fixed amount of 15.8 MW of regulating reserve to reflect the economic dispatch regulating reserve levels.

Additional Planning Studies

The Companies will continue to conduct forward looking planning studies which identify potential system impacts of plausible future generation, load, and interconnection scenarios and assess the relative value of potential mitigating strategies to accommodate them. The results of these studies help to inform the Companies, Commission, and other stakeholders about the technical and commercial impacts of the scenarios studied, as well as help to prioritize investments in system upgrades and identify risks if the upgrades are not pursued. Below are descriptions of some of the general planning studies that the Companies have conducted in the past.

Hawaiian Electric Studies

Big Wind Implementation Studies (Stage 1 Studies)

The HCEI Agreement contemplated that implementation studies will be conducted in three stages in order to systematically assess links between all the islands served by the Hawaiian Electric Companies and to analyze the impacts of the Big Wind Projects and other renewable energy resources on individual island systems affected by them. The three stages are:

- Stage 1: Linking all aspects of the Hawaiian Electric System with only the proposed Molokai wind farm and the Proposed Lanai Wind Farm via an undersea cable system.
- Stage 2: Linking the Maui electrical infrastructure to the Hawaiian Electric System to assess the ability of the inter-tied island grids to incorporate and reliably manage additional amounts of diverse renewable generation across the islands and operate the combined generation fleet more efficiently.
- Stage 3: Linking all aspects of the Hawaii Island (the Big Island) electrical infrastructure to the inter-tied Oahu/Maui configuration as described in Stage 2 to assess the ability of the inter-tied island grids to incorporate and reliably manage additional amounts of diverse renewable generation across the islands in the Hawaiian Electric Companies' service territories and operate the combined generation fleet more efficiently.

The Stage 1 studies were structured to facilitate the implementation of the Big Wind Projects, and were intended to identify Big Wind Project integration and performance requirements, undersea cable system requirements, and Hawaiian Electric System modifications, infrastructure additions and operating solutions.

The Stage 1 Studies were completed in 2011 and were functionally divided into two categories: (1) the Oahu Wind Integration and Transmission Studies

(OWITS); and (2) the Transmission/Cable Routing & Permitting Studies (TCRPS). These are the core planning studies that were necessary to assess both the technical and economic feasibility of the Big Wind Projects and requirements for the Oahu transmission lines and facilities needed to interconnect undersea cables delivering power from the Big Wind Projects to Oahu. In addition, the studies assessed the means to reliably and effectively integrate large amounts of wind-generated renewable energy located on the islands of Molokai and Lanai into the Oahu electric grid.

The OWITS were designed to identify project integration performance specifications/requirements, undersea cable system requirements, and Hawaiian Electric system modifications needed in order to address the ongoing challenges of integrating additional renewable resources into the Company's Oahu electrical grid. These studies included Hawaiian Electric's Electrical System Model Development and Validation effort, as well as supporting studies related to: (1) cycling, quick start capability; (2) generator unit response enhancements; (3) transmission and system integration; (4) renewable, environmental and fuels resource characteristics; and (5) system operations and controls.

The TCRPS consist of route and permit planning activities designed to better define the project scope and to provide sufficient information to initiate discretionary permits/approval processes and to initiate environmental reporting processes for the Oahu transmission lines and facilities necessary to interconnect the undersea cables. These activities included: (1) identification of detailed line routes; (2) identification of substation requirements; (3) identification of communication requirements; (4) determination of cable/conductor technologies; (5) identification of construction methods; (6) identification of operations and maintenance (O&M) requirements; (7) identification of land acquisition requirements; (8) development of cost estimates; (9) identification of project boundaries; (10) due diligence studies; and (11) agency consultations.

The Stage 1 Studies have been completed, and significant benefits have been gained from the considerable work completed in the studies. The Stage 1 Studies and related analyses indicate that Hawaii's interisland "Big Wind" renewable energy resource is a reasonable and cost-competitive alternative relative to other renewable resources that could be used to meet the required renewable portfolio standards (RPS) goals. As a result of the studies, Hawaiian Electric is now poised with a number of options that can be implemented in order to facilitate dramatic changes in the Company's operations, as the utility moves forward in step with state and national clean energy policy. In addition to informing the direction of Hawaii's inter-island wind efforts, the Stage 1 Studies have significantly advanced the general state of knowledge with respect to the Company's transmission system and generating units, which will help Hawaiian Electric integrate the maximum practical amount of intermittent, renewable power into the Company's grid.

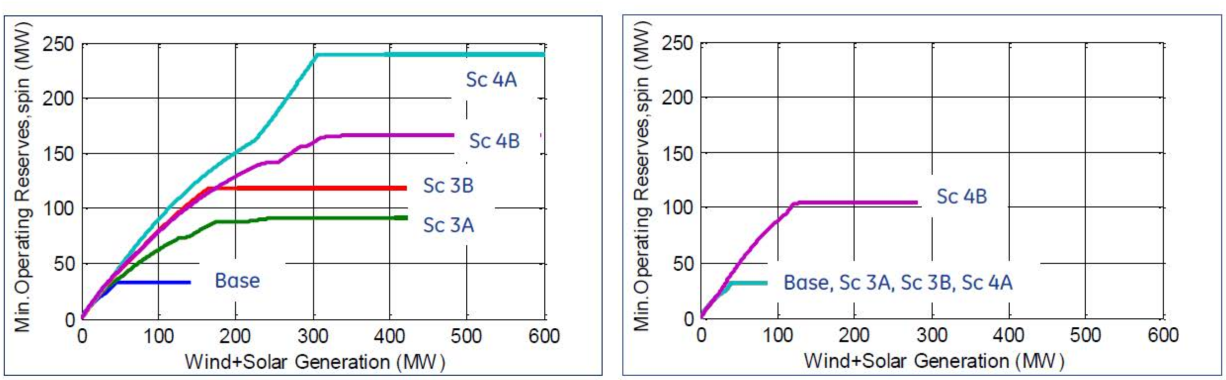
The modeling studies and system evaluation assessment work conducted in Phase I of Stage 1 of the OWITS resulted in the creation of a validated model of the Hawaiian Electric System. In Phase II of Stage 1 of the OWITS, this validated model enabled scenario and sensitivity analyses to be conducted on the Hawaiian Electric System, evaluation of impacts on generators, assessed operating costs and explored cost-effective mitigation measures for further refinement and implementation. Based on the OWITS results, a number of renewable-friendly system improvements for the Hawaiian Electric System have been identified as potential technical pathways toward accommodating more renewable energy generation on the Hawaiian Electric System including T&D infrastructure, operations upgrades, generator unit enhancements, renewable assessments and mitigation strategies.

Hawaii Solar Integration Study (HSIS)

The Oahu Solar Integration Study was initiated in March 2011 and analyzed the system level impacts of high penetrations of central station PV and distributed PV similar to the GE modeling studies for the OWITS. Key entities that participated in the OWITS are also involved in the Oahu Solar Integration Study, including GE International (through GE Energy Consulting), the National Renewable Energy Laboratory (NREL), AWS Truepower, and the Hawaii Natural Energy Institute (HNEI). The majority of the cost for this study is being covered by federal funds through NREL and HNEI. The HSIS report was completed in April 2013.

The study confirmed that the generation modifications recommended in the OWITS study would also be applicable to high penetration PV scenarios and with these modifications, the system would be able to accommodate the high penetration scenarios that were studied. It also showed that large Central station PV systems would require significantly more operating reserves than would large wind plants that could supply the same amount of energy. Figure 8- in the report below shows the additional reserves that would be required during the day when PV is on (left graph) and at night when just the wind in operation (right graph). Scenario 4A is the highest PV scenario and scenario 4B adds 200MW of wind and reduces the PV penetration to obtain roughly the same amount of renewable energy. Gaining frequency responsive PV and wind generation as well as load was also noted as being important to the integration of large scale wind and solar resources.

Figure 8-1. Operating Spinning Reserves Requirement in Different Scenarios



Stage 2 Oahu-Maui Interconnection Study (Stage 2 study)

The Stage 2 study was initiated in March of 2012. Key entities that participated in the Stage 2 study were GE International (through GE Energy Consulting) and the Hawaii Natural Energy Institute (HNEI). The cost for this study was split between HNEI, Hawaiian Electric, and MECO. The HSIS report was completed in May 2013.

The primary objectives of GE's Stage 2 scenario modeling studies are to assess the feasibility and quantify the value proposition of interconnecting: (1) MECO's Maui, Lanai and Molokai grids and operating them as one combined system; and (2) the Oahu, Maui, Lanai and Molokai grids and operating them as one combined system, taking into account several possible future scenarios consisting of different mixes of renewable generation and inter-tie configurations. The intent was to have the value of the interconnection benefits identified and rely on the bids in the RFP to provide the cost against which the value could be compared. The study did however incorporate interconnection cost estimates that were developed as part of the OWITS study as well as estimates that were developed in the current IRP transmission analysis to provide an indication of the cost benefit trade-offs for the different scenarios that were analyzed.

The Stage 2 study results again confirmed that the recommendations made in the OWITS and HSIS would also be applicable in the interconnection scenarios that were studied. In particular, investing in upgrades that would enable Hawaiian Electric and MECO to relax fixed operation schedules, and reducing the minimum operating levels of Hawaiian Electric's thermal generation. These modifications significantly increase the value of interconnecting the Hawaiian Electric and MECO systems.

The study also showed that:

- Interconnection offers a variety of benefits. It enables sharing of reserves and more efficient operation of the existing thermal fleets. In addition, it positions the system to accept more renewable generation and access to better sites for wind and geothermal generation.
- Scenarios with three AC cables and two DC cables are less economically favorable than the scenarios with single cables due to the increased capital cost associated with the additional cables and the increased level of curtailment.
- When the firm renewable generation (geothermal assumed in the study) is added a scenario, the economics become more favorable.
- Energy storage is more attractive as a reserve asset than as an energy shifting device. This is also consistent with the HSIS results.
- PPAs for renewable energy, especially wind and central solar resources, should have a tiered structure so that reducing curtailment benefits the utility and rate payer as well as the developer. Other structures are also possible, but the key aspect is that benefits of reduced curtailment should be shared in a manner that benefits all participants in a fair manner.

- The DC cables should be a system asset, not tied to any single renewable asset. This improves overall grid efficiency and available capacity on the cables can be used for additional future renewable energy sources. The nominal 200 MW rating of the cables was not found to be limiting in most cases, even with additional renewable sources.

Maui Electric Studies

Maui Energy Storage Study (Sandia Study)

The Sandia Study was prepared by Sandia National Laboratories and the final report was dated November 2012. MECO filed this study in its response to PUC-IR-15, Attachment D3. The purpose of the Sandia Study was to investigate strategies to mitigate anticipated wind curtailment on Maui. It analyzed different scenarios, most involving a battery energy storage system (BESS). The key findings are the estimated payback periods and net present values for the various scenarios.

Table 8-1 summarizes these results (Sandia Study at 10).

Table 8-1. Scenario Generation Costs (Million USD) and Project Economic Analysis

Scenario	Diesel	Wind	Diesel + Wind	Annual Savings	Estimated System Cost	Simple Payback (years)	Net Present Value[1]
Reference Run	194.8	45.0	239.8	–	–	–	–
10 MW/15 MWh BESS	190.0	46.3	236.3	3.5	11	3.1	34.4
10 MW/7 MWh BESS	187.7	48.0	235.7	4.1	35	8.5	12.7
10 MW/15 MWh BESS, no K4	185.9	48.6	234.4	5.4	35	6.5	30.6
25 MW Waena	189.8	7.7	237.6	2.2	25	11.4	5.3
25 MW/175 MWh BESS	180.2	49.4	229.7	10.1	87.5	8.7	29.6
25 MW/1200 MWh cryogen	185.2	49.4	234.6	5.2	31.25	6.0	40.3
30 MW Waena + 5 MW/35 MWh BESS	185.5	48.6	234.1	5.7	47.5	8.3	31.0
35 MW Waena + transmission line	188.9	47.7	236.7	3.1	40	12.9	2.7

[1]Net present value (NPV) calculations assume a 30-year total project life with no terminal value. Those involving battery storage assume a 15-year battery stack life, and that the replacement stack would cost 60% of the initial capital cost.

Explanation of table nomenclatures are as follows:

- Reference Run – K1 and K2 operate on alternating days between 2 pm and 11pm and K3 and K4 baseloaded.
- 10-MW/15MWh BESS – battery used for 10 MW of spinning reserve, but not time of day shifting.
- 10-MW/70-MWh BESS – battery used for 10 MW of spinning reserve and time of day shifting.

- 10-MW/70-MWh BESS, no K4 offline – Same as previous scenario but K4 is offline.
- 25-MW Waena – Five 5-MW highly flexible biofueled internal combustion engines installed at Waena. K3 and K4 are offline and a capacitor bank is likely needed on the 23 kV system (not included in costs).
- 25-MW/175-MWh BESS – battery used for 25 MW of spinning reserve as well as time of day shifting. Units K3 and K4 are offline, and a capacitor bank is needed (not included in costs) if the BESS is not located on the 23 kV system.
- 25-MW/1200-MWh cryogen – 25 MW cryogen storage system with a single turbine with a minimum output of 8MW. K3 and K4 are offline.
- 30 MW Waena Plant + 5-MW/35 MWh battery – Six 5-MW highly flexible biofueled internal combustion engines at Waena and a 5 MW/35 MWh battery on the 23 kV system and a capacitor bank would be needed (not included in costs) on the 23 kV system. Kahului Power Plant is offline.
- 35-MW Waena Plant + Transmission Line – Seven 5-MW highly flexible biofueled internal combustion engines at Waena that allow Kahului Power Plant to be offline. A new transmission line is built between the 23 kV and the 69 KV systems.
- Diesel – The cost of diesel fuel consumed.
- Wind – The amount wind energy purchased.

The key findings were that many of the scenarios have payback periods less than 10 years. The savings from installing a battery came mostly from its ability to increase efficiency of the MECO units, as shown in the reduction in diesel fuel cost in the "diesel" column above, and not from reduced curtailment since the study took into account the cost of purchasing additional wind energy. (The battery option with the shortest estimated payback period assumed normal Kahului Power Plan operations continue.) Several caveats were also included in this study: cost savings are based on a single year and assumed those savings will continue annually going forward, costs were not adjusted to represent Hawaii costs (that is, additional shipping, other logistical support, and any wage rate differential), and the regulating reserve requirement used for the study differed from MECO's actual practice.

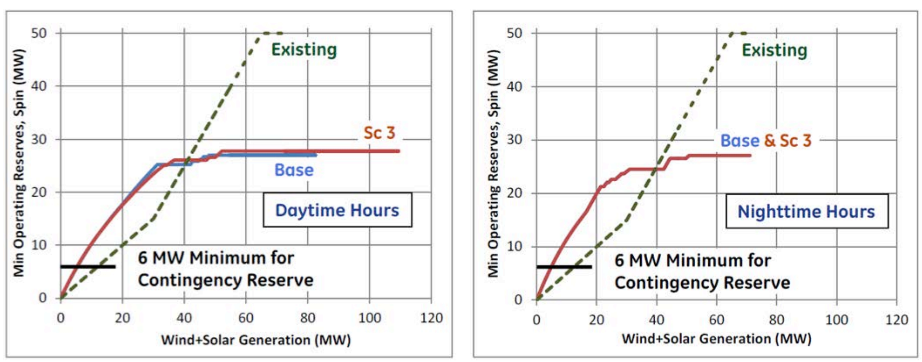
MECO is currently learning to operate with three wind farms connected to its Maui grid and is working to modify its operating practices to better accommodate them. The Company is currently reviewing the study to determine if the assumptions vary from the current circumstances enough to warrant additional analysis before determining the next steps. For example, since MECO is in the process of reducing the minimum operating outputs for K3 and K4 and counting K3, K4, M15, and M18 as providing regulating reserve up, it is evaluating how these changes would impact the battery option.

Hawaii Solar Integration Study (HSIS)

General Electric prepared the final HSIS report, dated March 25, 2013. MECO filed a draft summary in its response to PUC-IR-15. The Company is filing the final report and the HSIS Summary Technical Report in its June 12, 2013 supplemental response to PUC-IR-15, Attachments D7 and D7A, respectively. The HSIS follows up study the Oahu Wind Integration and Transmission Study (OWITS)[40] completed in 2010. It focuses on the operating impacts of higher penetrations of solar energy on the Oahu and Maui bulk power systems.

Generally, this study found that lowering MECO generation would decrease curtailment, but the study's conclusion was based on assumptions that MECO would run its combustion turbines and Kahului units without some of the constraints that MECO currently has in its operation and changing the way MECO commits units to place a priority on reserves. The study also evaluated a BESS and recommended further analysis on reserve requirements. This study used a generated wind and solar data set to determine a statistical regulating reserve requirement for the Maui system that was a function of the wind and solar generation on the grid at any given time. The basis for the reserve requirement assumed in the study was that statistically the regulating reserve should be sufficient for 99.99% of the ramps in wind and solar generation. This is different than the current MECO reserve requirement which is only a function of delivered wind power. The two reserves are compared graphically in Figure 8-2.

Figure 8-2. Maui Operating Reserve Requirements (including BESS)



The HSIS report states that it is difficult to compare the two methods of carrying regulating reserve. These graphs (HSIS Summary Technical Report at 38) show that at times each method will carry more or less reserves than the other. Additionally the existing regulating reserve requirement is based on delivered wind power alone, whereas the HSIS regulating reserve is based on delivered wind plus solar power, which moves the requirement further up the curve on the proposed reserve requirement only. Considering that solar DG for Maui is approaching 30 MW, the difference can be significant. No analysis compares the proposed reserve requirement to the existing reserve requirement at a time that relates to the effect on integration of renewable energy or the differing impacts

[40] For a summary discussion of the OWITS, see *Request to Recover Deferred Costs for Big Wind Implementation Studies*, Exhibit 2, filed May 9, 2011, Docket No. 2009-0162.

that may occur on different independent power producers because of the excess energy curtailment order of the wind farms, where KWPII is curtailed first, Auwahi Wind Energy is curtailed second and KWPI is last to be curtailed. (MECO is in the process of including M15, M18, K3, and K4 units in its up reserve, which effectively lowers MECO's "existing" reserve requirement over what is shown in the green dashed line in the above figures.)

Two curtailment mitigation strategies performed well in the analysis: (1) changing the way MECO commits combined cycle units; and (2) installing a BESS. Only the benefits were assessed, therefore no costs were included for the BESS or unit modifications required to allow the combined cycle units to operate in single or dual train mode and the overall cost effectiveness of the alternatives was not evaluated as part of this study. The study recommended that MECO examine its down reserve requirement to ensure it can cover the loss of the largest circuit. The study found that additional non-curtailable DG added to curtailment of the curtailable wind facilities – in particular KWP II (Table 8-2). Distributed solar increased by 24 GWhs between the Baseline and No Burning Desire, which caused an additional 8 GWhs of curtailment to KWP II over the baseline amount.

Table 8-2. Wind and Solar Energy by Plant

Energy	Baseline	No Burning Desire
KWP1 Available Energy (GWh)	129	129
KWP1 Curtailed Energy (GWh)	3	2
KWP1 Delivered Energy (GWh)	126	126
KWP1 Capacity Factor	48%	48%
Auwahi Available Energy (GWh)	88	88
Auwahi Curtailed Energy (GWh)	18	18
Auwahi Delivered Energy (GWh)	70	69
Auwahi Capacity Factor	38%	38%
KWP2 Available Energy (GWh)	90	90
KWP2 Curtailed Energy (GWh)	46	54
KWP2 Delivered Energy (GWh)	45	36
KWP2 Capacity Factor	24%	20%
Central Solar Available Energy (GWh)	0	30
Central Solar Curtailed Energy (GWh)	0	14
Central Solar Delivered Energy (GWh)	0	15
Central Solar Capacity Factor	0%	12%
Distributed Solar Available Energy (GWh)	25	49
Distributed Solar Curtailed Energy (GWh)	0	0
Distributed Solar Delivered Energy (GWh)	25	49
Distributed Solar Capacity Factor	19%	19%

Generation Reserves/Cycling Study (Cycling Study)

The Cycling Study was prepared by Electric Power Systems, Inc. (EPS) / Intertek / Aptech) and the draft report was dated May 30, 2013.

As MECO and HELCO both desire to maximize the use of renewable energy in the most economic and reliable manner possible for their customers, MECO and HELCO contracted with EPS to analyze possible generation dispatch alternatives to maximize the use of renewables that are currently in service or planned to be in service in the near future.

The Cycling Study analyzed the security constraints on the MECO system and found that:

- There were no stability constraints as long as the MECO regulation constraint is met.
- Either K3 or K4 plus K1 or K2 is required during peak conditions due to transmission restrictions.
- There were no restrictions on under frequency load shedding or rate of change of frequency as long as the MECO regulation constraint is met.
- The generation ramping capability must exceed 5 MW/min.
- MECO's regulation constraint was 6 MW or ½ MW for every 1 MW of wind up to 30 MW of wind, and 1 MW for each MW of wind above 30 MW, with a targeted maximum of 50 MW of regulation.

Probabilistic production cost modeling was performed on the MECO system. The study stated that probabilistic production cost modeling is the preferred method of completing long-term productions cost simulations with variable generation from renewable energy; however, it cannot be used by operations personnel for short-term unit-commitment decisions to implement the recommendations of the study.

Operational Flexibility Study for the Integration of Renewable Energy (Stanley Studies)

The Stanley Studies were prepared by Stanley Consultants, Inc. The final Stanley Phase 1 Study was dated February 2011 and filed as MECO-703. The final Stanley Phase 2 Study was dated December 12, 2012 and is being filed in MECO's June 12, 2013 supplemental response to PUC-IR-15, Attachment D9.

Due to the operational challenges encountered after MECO incorporated the first wind energy resource (KWPI) onto its Maui grid, the pending integration of two additional wind resources (Auwahi and KWPII), coupled with growing installation of photovoltaic systems, MECO contracted Stanley to address the potential impacts and mitigating measures for accommodating larger amounts of renewable energy on its Maui grid.

The Stanley Phase 1 Study provided 12 recommendations and high level budgetary costs to improve wind integration onto the Maui grid (HELCO-703 at 76). The Stanley Phase 2 Study further examined the seven most promising recommendations, provided more detailed cost estimates, assessed potential environmental impacts, and tested several units for expanding operating range. The seven recommendations explored in the Phase 2 Study and the revised cost estimates are shown in Table 8-3 (Stanley Phase 2 at 62), which is shown below for ease of reference:[41]

Table 8-3. Cost Estimates (Thousands of Dollars) and RPS

Modification	Unit Cost	Total Cost	Improved RPS (2020)	Cost per 1/10% RPS
Upgrade Burners for Kahului 3 & 4	$254	$508	0.9%	$56,400
Modify OTSGs for Lower Loads	$738	$1,475	2.1%*	$70,200
Modify HRSGs for Cycling and Lower Loads	$3,832	$7,664	3.5%	$219,000
Install Inlet Chilling on Combustion Turbines	–	$9,764	0.3%	$3,254,700
Install a 10 MW 90-minute BESS	–	$39,005	1.1%	$3,546,000
Install Engine Preheating (M10–M13)	$2,222	$8,888	Unknown	n/a
Install Data Historian for Generating Units	–	$152	n/a	n/a

* The Cause of the M18 steam turbine backend blade erosion needs to be determined.

Besides quantifying these seven recommendations, Stanley also qualified that new source review (NSR) and new source performance standards (NSPS) for environmental impacts need to be evaluated for recommendations nos. 1, 4, and 6 in the table above. Stanley also qualified that emission rates need to be evaluated to ensure compliance with other environmental regulations. (See Stanley Phase 2 Study at 57 and 65.)

Of the seven recommendations, the burner upgrades for K3 and K4 at KPP were determined to have a very good RPS value for the dollar investment (Stanley Phase 2 at 56). Stanley also qualified that before this modification is implemented, environmental constraints should be evaluated (Stanley Phase 2 at 57).

This recommendation was placed into MECO's 2012 capital budget. However, during the environmental review process, it was determined that this project had high potential of triggering a new source review (NSR) of KPP by the U.S. Environmental Protection. After the burner upgrades, MECO would be required to do a stack test and compare to its last 2010 stack testing results. If any of the constituents were increased (CO (carbon monoxide), NOX (nitrogen oxide), particulate, SO2 (sulfur dioxide)) then KPP would require a NSR and this would require MECO to make additional changes. Some of these changes would be, but are not limited to, switching fuel to diesel, backend controls (SCR: selective catalytic reduction), oxidation catalysts, particulate reduction technology) and/or the potential of immediate shut down of operations versus fines to be imposed until compliance is achieved. Because of these environmental related risks, MECO decided not to move forward with this recommendation.

[41] OTSG = Once Through Steam Generator; HRSG = Heat Recovery Steam Generator

In the recommendation section of the Stanley Phase 2 Study, Stanley concluded the following for the remaining six recommendations:

- Modify OTSGs for Lower Loads – Back-end moisture damage on the M18 steam turbine remains an obstacle that prevents giving a full recommendation at this time (Stanley Phase 2 Study at 58)
- Modify HRSGs for Cycling and Lower Loads – Shows the greatest RPS improvement by a wide margin. The modifications necessary to achieve this are highly recommended. (Stanley Phase 2 Study at 57). (While Stanley endorsed this recommendation based on the cost per 1/10% RPS improvement basis, MECO decided against this recommendation because the RPS improvement to be gained would not justify the estimated cost of $7.7 million.)
- Install Inlet Chilling on Combustion Turbines – This modification now only has marginal value for the investment. Capital cost was much higher than expected due to space constraints for new equipment (Id.)
- Install 10 MW 90 Minute BESS – The most expensive modification and RPS gains are fairly meager. Recent BESS industry fires hang a cloud of uncertainty over equipment reliability (Stanley Phase 2 Study at 58)[42] (While Stanley included this conclusion in the Stanley Phase 2 Study, MECO, along with Hawaiian Electric and HELCO, view energy storage as part of a portfolio of potential solutions to manage current resources and to help reliably integrate as much renewable energy as possible to the three utilities' island grids. MECO is currently commissioning a 1 MW lithium ion BESS at its Wailea substation on Maui, pursuing a BESS project on Molokai, and testing potential benefits of two energy storage systems on Maui as part of the ongoing Maui smart grid demonstration projects.)
- Install Engine Preheating (M10-M13) – Fairly expensive option in order to reduce start time from 90 minutes to 50 minutes. It is expected that there is some benefit but it is unclear if the high capital cost is justifiable. (Id.)
- Install Data Historian for Generating Units – Relatively inexpensive and would provide significant value to operations and engineering personnel (Id.) (This recommendation has no impact to the integration of additional wind energy onto the Maui grid. Additionally, MECO's current distributed control system by ABB System has historian capabilities. MECO plans to upgrade its current distributed control system.)

KWPII Wind Integration Study (WIS)

The WIS was prepared by General Electric and the final report was dated June 2010, and filed in MECO's response to PUC-IR-15, Attachment D1. MECO and First Wind (FW) commissioned GE to perform the WIS to consider the expansion of the 30 MW KWPI wind plant, owned by FW, by an

[42] Hawaii has also had its own experience with BESS fires. Kahuku Wind has experience three separate fires with its BESS since operation began in March 2011. The third incident in August 2002 was a major fire which destroyed the 12,000 battery packs and the supporting infrastructure and building.

additional 21 MW. The impact of the planned 21 MW Auwahi wind plant was also considered.

Early in the study efforts, GE determined that the third wind farm (that is, KWPII) would not be viable unless some mitigation measures were implemented. The study went on to analyze various mitigation options and determined which would be the most beneficial. For the most part the mitigation measures were documented as the Maui Operation Measures (MOMs) in the KWP II PPA. (Some measures were changed slightly in subsequent negotiations between FW and MECO. See page 12 for the current status of implementing the MOMs.)

Kahului Power Plant Reduced Operations: Transmission System Impact and Requirements (KPP Transmission Study)

The KPP Transmission Study was prepared by Hawaiian Electric's Transmission Planning Division. The draft KPP Transmission Study was dated June 2012 and filed in MECO's response to PUC-IR-15, Attachment D5. MECO filed the final KPP Transmission Study, dated March 7, 2013, in its supplemental response to PUC-IR-15, Attachment D5.

The KPP Transmission Study was commissioned to analyze the transmission requirements for the overloading and undervoltage problems that occur due to reducing the generation at KPP. The KPP Transmission Study describes transmission system impacts and requirements as a result of reduced operations at KPP and the alternatives to alleviate these impacts. The study described that without the operation of the KPP generating units, low voltage issues will occur in the 69/23 kV transmission system, in addition to overloading equipment during contingency conditions evaluated in the study.

The study identified five alternatives and recommended study alternative 2, which is the upgrade of the existing 23 kV Waiinu substation to Kanaha substation transmission line to a 69 kV transmission line, together with performing additional work to reconductor two other existing transmission lines. MECO accepts the study recommended alternative 2 to pursue the Waiinu substation to Kanaha substation transmission line upgrade project and will also plan to perform the additional reconductoring work identified in the study. As stated above, costs for these projects are to be included in MECO's 2014–2018 capital budget.

Hawaiian Electric Light Studies

Generation Reserves/Cycling Study (Cycling Study)

The Cycling Study was prepared by Electric Power Systems, Inc. (EPS) / Intertek / Aptech) and the draft report was dated May 30, 2013.

As MECO and HELCO both desire to maximize the use of renewable energy in the most economic and reliable manner possible for their customers, MECO and HELCO contracted with EPS to analyze possible generation dispatch alternatives to maximize the use of renewables that are currently in service or planned to be in service in the near future.

The Cycling Study analyzed the security constraints on the HELCO system prior to the Hu Honua facility being added to the system and after. The draft report states the following system constraints.

HELCO – Pre Hu Honua:

- The system requires two steam units to be running to maintain stability
- Keahole CC must be online during peak load conditions mitigate transmission constraints (preventing voltage collapse and line overload)
- At least three large units (Combined cycle = 2 large units) are needed to maintain the similar system reliability for loss of generation events
- At least four large units, with some exceptions when three large units are sufficient, are required to maintain an acceptable rate of change of frequency.
- The system generation ramp rate must exceed 4 MW/minute to maintain adequate frequency regulation capability.
- Regulation: No changes to current operating policy.

HELCO – Post Hu Honua:

- The system requires two steam units to be running to maintain stability.
- Keahole CC must be online during peak load conditions mitigate transmission constraints (preventing voltage collapse and line overload).
- At least two large units in addition to Hu Honua & PGV are needed to maintain the similar system reliability for loss of generation events.
- At least two large units in addition to Hu Honua & PGV are required to maintain an acceptable rate of change of frequency.
- The system generation ramp rate must exceed 4 MW/minute to maintain adequate frequency regulation capability.
- Regulation: No changes to current operating policy.
- As noted in the study, the results of the study are not actionable. HELCO has developed a road-map to work towards the optimal dispatch identified in the study. HELCO began cycling HEP in the first quarter of 2013 and deterministic production runs utilizing the minimum security constraint rules identified in the cycling study are underway.

Modeling and Analysis

The Companies analyzed each utility's system individually and sometimes as a consolidated system. A majority of the analysis was performed through the Strategist model. (See *Appendix M: Strategist Integrated Planning System* for detailed information.) Other analysis was done through the use of Excel.

Process for IRP Analysis

Example Inputs	Modeling Analysis	Example Outputs
Load Forecast Resource Options Fuel Price Forecast Transaction Profiles Maintenance Schedule	Strategist	Resource Plans Total Resource Cost Revenue Requirements Fuel Consumption Other Outputs
Strategist Outputs Infrastructure Costs Transmission Costs	Excel	Monthly Bill Impact RPS Percentage GHG Emissions All Other Quantitative Metrics
Resources and Plans Quantitative Metrics AG Input Other Information	Qualitative Assessment	Potential impacts on, and compatibility with, community lifestyles for resources. Potential impacts to Hawaii's culture and the cultural values for resources.

Inputs to the Strategist Model

Some of the inputs used with the Strategist Model include:

- Hourly load shape based on historical 8760 demand (sales and peak) forecasts.
- EEPS forecasts.
- Non-thermal transactions (such as wind, photovoltaics, and hydro).
- Demand-side options (such as energy efficiencies and demand response).
- Supply-side resource options (such as geothermal, biomass, and combustion turbine).

Strategist Model Process for Outputs

Strategist is an integrated planning system that employs dynamic programming to develop optimal portfolios of resources and analyze all functional areas of utility planning.

Strategist generates 20-year resource plans through a modeling algorithm and utility revenue requirements for fuel, purchase power, capital for resources added by the model, and operating and maintenance costs. These model revenue requirements were added to revenue requirements for the base capital addition projects that are added yearly and future non-generation related major projects.

The table below presents the assumptions for costs that were added to resource plans, as applicable. These costs were converted to revenue requirements and included in the total resource cost of the plans and nominal rate metric calculations.

Table 8-4. Resource Plan Cost Assumptions

	2014	2015	2016	2017	2018	Future Years
Hawaiian Electric						
Base Capital (Production)[43]	$41,600,000	$32,400,000	$47,000,000	$50,000,000	$50,000,000	$50,000,000 per year
Base Capital (Transmission)	$133,120,000	$103,680,000	$150,400,000	$160,000,000	$160,000,000	$160,000,000 per year
Transmission Projects (Moved by Passion)				$38,800,000		$228,000,000
Transmission Capital (Honolulu PP Retirement)	$12,000,000					
Diesel Conversion			$75,424,974			
Air Quality Controls					$282,100,000	$692,600,000
LNG Existing						$370,000,000
LNG New						$105,000,000
Smart Grid	$300,000	$900,000	$900,000	$16,800,000	$35,600,000	$35,600,000
HELCO						
Base Capital (Production)[35]	$2,560,000	$2,760,000	$2,320,000	$2,520,000	$2,520,000	$2,520,000 per year
Base Capital (Transmission)	$52,480,000	$56,580,000	$47,560,000	$51,660,000	$51,660,000	$51,660,000 per year
Transmission Projects (Moved by Passion)				$42,500,000		$24,500,000
Air Quality Controls						$208,800,000
LNG Existing						$8,000,000
Smart Grid		$100,000	$100,000	$2,200,000	$9,600,000	$9,800,000

[43] The base production capital was reduced in plans with unit decommissions and deactivations.

	2014	2015	2016	2017	2018	Future Years
MECO						
Base Capital (Production)[35]	$9,430,000	$12,420,000	$14,260,000	$16,790,000	$16,790,000	$16,790,000 per year
Base Capital (Transmission)	$31,160,000	$41,040,000	$47,120,000	$55,480,000	$55,480,000	$55,480,000 per year
Transmission Projects (Moved by Passion)		$11,200,000		$23,400,000		$20,320,000
Transmission: Waena						$7,000,000 in resource year
Transmission: Geothermal						$38,000,000 in resource year
Transmission: Biomass						$4,600,000 in resource year
Air Quality Controls						$220,800,000
LNG Existing						$12,000,000
Smart Grid		$100,000	$100,000	$2,100,000	$8,100,000	$8,200,000

Missing from Table 8-4 are the deactivation and retirement costs because the retired units and the retirement year varied among resource plans. The operations and maintenance cost for deactivating a unit was $1 million for the first year and $500,000 for each subsequent year. The assumption for retirement capital costs were $10 million for steam units, $4 million for Shipman, and $2 million for small diesels. The capital costs were converted to revenue requirements using revenue removal requirement factors when applicable.

Hawaiian Electric Modeling and Analysis

Modeling runs were made to determine what firm resources are required to meet the planning criteria in each scenario. These "timing" runs identify the minimum amount of generation required to meet the planning criteria in each year accounting for peak load, capability of units running, planned maintenance of units, and unplanned outages. For Hawaiian Electric, the reliability guideline usually governs when units are required to be added to the system. *Appendix O: Resource Plan Sheets* contains all modeling runs described here.

These timing runs assess the need to add new firm generation resources to the system under different load growth scenarios. In the firm timing runs, different firm supply-side resources, both conventional and renewable, were made available for the model to add when the capacity planning criteria was violated. In a similar approach to the supply-side resources, runs were performed with and without future demand response programs to determine the cost effectiveness of these programs.

New Firm Generation Requirements

The timing runs for Blazing a Bold Frontier show that no additional generation is required to meet the planning criteria because peak loads are declining (see plan P1_2a1X-1r2). With the existing system capability (no units retiring), Stuck in the Middle also shows that no additional generation is required to meet the planning criteria even though peak loads are slightly increasing over the 20 year planning horizon (see plan P2_2a1NRetire-1r12). For No Burning Desire, peak loads are increasing making new generation required to meet the planning criteria (see plan P3_2a1N-1r0). Like the first two scenarios, Moved by Passion requires no new generation to meet the planning criteria (see plan P4_2a1X-1r0).

Deactivating or Decommissioning Units

Modeling runs were also made to assess the timing when deactivation or decommissioning (retirement) of units or PPA contracts were contemplated as a strategy in each scenario. From a capacity planning criteria perspective, it does not matter whether the units were deactivated or decommissioned (retired) because the capacity from these units was not available to meet the planning criteria.

In Blazing a Bold Frontier, loss of the approximately 199 MW by the deactivation of Honolulu 8 and 9 and Waiau 3 and 4 the capacity planning criteria does not trigger the need for new capacity (see plan P1_2a1XRetire-1r2) because of the declining peak loads in this scenario. Even the loss of 208 MW in 2017 from the end of the Kalaeloa Power Purchase Agreement does not trigger the need for new capacity (see plan P1_2A1XRETIRE-1R7 T4exp). If a large block of capacity is loss from the system due to a mass (approximately 1,100 MW) decommissioning of units over a few years, new capacity is required to meet system planning criteria. This is shown in the plan P1B2a1xRetire-2r4 which deactivates Waiau 3 and 4 in 2017; Honolulu 8 and 9 in 2019; Waiau 5, 6, 7, and 8 in 2020; Kahe 1, 2, 3, & 4 in 2020; Kahe 5 in 2021; and Kahe 6 in 2022. However, if units are deactivated strategically as the peak load decreases, the need for replacing generation to meet planning criteria could be avoided altogether. This is show in plan P1_2A1XRETIRE-1R7 T3exp which shows the results of a modeling run that was conducted where the deactivation schedule was determined by the model.

For futures where the peak load increases or remains level, the loss of capacity from the deactivation or decommissioning of units triggers the need for replacement generation to meet the planning criteria. This is shown in plans P2_2a1XRetire-1r1, P2_2a1NRetire-1r3, P2_2a1NRetire-4ER0 Timing, P2_2a1NRetire-4ER1 Timing, and P2_2a1NRetire-1r10 for Stuck in the Middle, for different decommissioning strategies of existing units and IPP contracts. For No Burning Desire, which has the highest peak load increases, the impacts of different decommissioning strategies are shown in plans P3_2a1NRetire-1r0 and P3B2b1NRetire-4Er0. For Moved by Passion, the impacts of different decommissioning strategies are shown in plans P4_2a1XRetire-1r0 and P4B2b1NRetire-4Er1.

Assessing Supply-Side Resources

Assessments of the various supply-side resources were also conducted by allowing the Strategist model to develop resource plans from the supply side resources in each scenario. Resource plans were also developed by fixing various supply-side resources into plans to provide a comparison of their cost effectiveness against other resources. The lowest cost study period resource plan out of the tens and, in some runs, hundreds of resource plans was analyzed by the model using various combinations of supply-side resources. Overall, PV and Wind resources are found in the lowest cost resource plans in all four scenarios which suggest that these two resources are the most cost effective resources based on the given assumptions at this time.

HELCO Modeling and Analysis

In the initial phase of the modeling analysis for HELCO, modeling runs were made to determine the firm resources required to meet the planning criteria in each scenario. These firm "timing" runs identify the minimum amount of generation required to meet the planning criteria in each year accounting for peak load, capability of units running, and planned maintenance of units. For HELCO, the Rule 1 criteria usually governs when units are required to be added to the system.

In the HELCO firm timing runs, different firm supply-side resources, both conventional and renewable, were made available for the model to add when the capacity planning criteria was violated. Plans with and without Hu Honua were run to see the project's impact on the need for future firm resources. In conjunction with the addition of the Hu Honua resource, it was assumed that the Shipman 3 and 4 generating units would be deactivated the following year. In a similar approach to the supply-side resources, runs were performed with and without future demand response programs to determine the cost effectiveness of these programs. See "Understanding the Resource Plan Sheets" (page 8-28) for the results of these runs. For all of the modeling runs, it was assumed that the only baseload units were Keahole combined cycle, PGV, and Hu Honua (HEP if Hu Honua was not in-service).

Adding New Firm Generation

These timing runs assess the need to add new firm generation resources to the system under different load growth scenarios. The timing runs for Blazing a Bold Frontier show that, with peak loads declining, no additional generation is required to meet the planning criteria (see plan H1_2A_X-1r0). Stuck in the Middle also shows that no additional generation is required to meet the planning criteria even though peak loads are slightly increasing over the 20 year planning horizon (see plan H2_2A_X-1Ar0). No Burning Desire, with steeply increasing peak loads, new generation is required even with Hu Honua and the implementation of a demand response program (see plan H3_2A_N-1r0). Like the first two scenarios, Moved by Passion requires no new generation to meet the planning criteria (see plan H4_2A_X-1ARr0).

Deactivating or Decommissioning Units

Modeling runs were also made to assess the timing when deactivation or decommissioning (retirement) of units or PPA contracts, were contemplated as a strategy in each scenario. From a capacity planning criteria perspective, it does not matter whether the units were deactivated or decommissioned (retired) because the capacity from these units was not available to meet the planning criteria. For HELCO, the deactivation of Shipman 3 and 4 (13.5 MW) was only analyzed in combination with the addition of Hu Honua (21.5 MW). The retirement of the all HELCO utility generation, except for Keahole combined cycle, was considered in Complying with Environmental Standards (page 9-18).

Based on the results of the firm timing analysis under the different scenarios, the geothermal resource was the most cost effective firm resource due to its low operating costs. For Blazing a Bold Frontier, see the H1_2A_X-1br0 resource plan; for Stuck in the Middle, see the H2_2A_X-1Br0 resource plan; for No Burning Desire, see the H3_2A_N-1r0 resource plan; and for Moved by Passion, see the H4_2A_X-1Br0 resource plan.

With the cost effective resources firm resources identified in the firm timing analysis, assessments of the various non-firm supply side resources were also conducted by allowing the Strategist model to develop resource plans from the many non-firm supply side resources in each scenario. Overall, PV and Wind resources are found in the lowest cost resource plans in all four scenarios which suggest that these two resources are the most cost effective resources based on the resource costs and specifications from the Unit Information Forms. The lowest cost study period resource plan out of the tens and, in some runs, hundreds of resource plans was analyzed using various combinations of supply-side resources.

MECO Modeling and Analysis

Maui Analysis

MECO followed the same procedure to assess firm capacity need and timing. These firm “timing” runs identify the minimum amount of generation required to meet the planning criteria in each year accounting for peak load, capability of units running, and planned maintenance of units. For MECO, the Rule 1 criteria govern when units are required to be added to the system.

These timing runs assess the need to add new firm generation resources to the system under different load growth scenarios. In the firm timing runs, different firm supply-side resources, both conventional and renewable, were made available for the model to add when the capacity planning criteria was violated. In a similar approach to the supply-side resources, runs were performed with and without future demand response programs to determine the cost effectiveness of these programs.

Adding New Firm Generation

In Blazing a Bold Frontier, no firm units are needed to meet capacity need for the 20 year planning period with 110% achievement of the EEPS and Fast DR program (see run M1_2a_X-1r3). In Stuck in the Middle, firm units are needed in year 2029 with 75% achievement of the EEPS and the full portfolio of DR programs (CIDLC, RDLC, and Fast DR) (see run M2_2__N-1r1). In No Burning Desire, new capacity is needed over several years beginning in 2015 (see run M3_2__N-1r1) when there is 75% achievement of the EEPS and the full portfolio of DR programs implemented. In Moved by Passion, no new capacity is needed with 100% achievement of the EEPS and Fast DR program. Geothermal is added to lower cost in 2033 but not needed to meet capacity criteria (see run M4_2a_X-1r0).

Deactivating or Decommissioning Units

Modeling runs were also made to assess the timing when deactivation or decommissioning (retirement) of units or PPA contracts, were contemplated as a strategy in each scenario. From a capacity planning criteria perspective, it does not matter whether the units were deactivated or decommissioned (retired) because the capacity from these units was not available to meet the planning criteria.

For Maui, the Power Purchase Agreement with HC&S was analyzed for its contract terminated in 2014 and also under extension beyond 2014. For planning purposes, the contract was assumed to continue indefinitely. With HC&S continuing operations, new capacity needs in future years can be deferred (see run M2_2b_X-1r0).

The retirement of the all MECO utility generation, except for the Maalaea combined cycle units, was considered in Complying with Environmental Standards (page 9-18).Across the four scenarios, existing generation was considered to be deactivated and replaced by more efficient biofuel generation or geothermal to meet future environmental regulations. The retirement creates a capacity need that must be fulfilled by firm units.

After the capacity planning criteria was met, the entire breadth of supply side resources was screened with the units added for firm timing fixed in the resource plans. The screening was used to determine if additional resources could be added to the system to lower cost. Consistent across all scenarios, PV and wind resources were identified to be most cost effective additions.

Lanai and Molokai Analysis

Analysis was conducted for the islands of Lanai and Molokai built on MECO's foundational analysis. As with all utilities, see *Appendix O: Resource Plan Sheets* for a description of the resource plans used in our analysis.

Assumptions

A number of assumptions and methodology helped determine the timing and amount of renewable resources to add:

- The earliest a new resource is added is 2018.
- Resources are added in the MW increments defined in the applicable Unit Information Form.
- All increments of each type of resource are added in the same year.
- In the mixed renewable resource plan, wind and battery are added in 2018, wave in 2019, and biomass in 2020.
- A minimum of one increment of each renewable resource required for the strategy was added.
- Additional increments were added as needed to satisfy the energy demand in each scenario. In the mixed renewable resource strategy, additional increments of the lowest cost option were added (biomass).
- More than one increment of a renewable resource resulting in curtailment was only considered acceptable if the NPV was lower with the additional increment of renewable resource.
- Additional increments of renewable resource were added until the lowest NPV was reached (that is, adding one more increment would result in increased NPV). There were several exceptions to this approach in which an additional increment increased the NPV slightly, but was necessary to provide comparability across resource plans. These exceptions are noted in the relevant resource plan sheets.
- Battery storage was included in all resource plans that include additional as-available renewable generation.

Description of Our Analysis

The need for additional firm generation capacity during the planning period was assessed. Account forecasted peak demand from each Scenario, existing generation capacity, and Rule 1 capacity planning criteria for reliability acted as a basis for this analysis. Under these considerations, neither Lanai nor Molokai required additional firm generation capacity to reliably meet forecasted peak demand.

Analysis showed that the current operation of Lanai and Molokai generation resources complies with all current environmental regulations as well as those expected to take effect during the planning period. Thus, no additional measures are necessary.

To address the Principal Issues and to respond to Advisory Group and public comments from December 2012 meetings, analysis evaluated various resources and resource plans. Some Principal Issues did not apply to Lanai or Molokai; Table 8-5 clarifies which Principal Issues were addressed.

Table 8-5. Principal Issues Addressed for Lanai and Molokai

Issue	Description	Addressed
1	Replace Existing Fossil Fuel Generating Plants	Yes
2	Inter-Island Connectivity	Yes (via separate analysis)
3	Geothermal Resources	Not Applicable
4	Energy Storage	Yes
5	Waste-to-Energy Facilities	Not Applicable
6	Best Use of Hawaiian Electric CIP CT-1 Generating Facility	Not Applicable
7	Reasonable Cost and Rate Impacts	Partially (via Scenarios)
8	RPS Rate Impact	Partially (via Scenarios)
9	EEPS Rate Impact	Yes
10	Captive Customer Rate Impact	Yes
11	Inter-Island and Inter-Utility System Transmission	Yes
12	Smart Grid Implementation	Yes
13	Environmental Regulation Compliance	Yes
14	Fuel Supply and Infrastructure	Yes
15	Fossil Fuel Generation Resources	Yes
16	Essential Grid Ancillary Services	Not Applicable
17	Transmission Planning Analysis	Yes

Although no capacity need is projected for Lanai or Molokai, the Companies still analyzed 100% renewable options and options to reduce cost for each island. The Companies reviewed the June 2012 National Renewable Energy Laboratories (NREL) technical report entitled *Integrating High Levels of Renewables into the Lanai Electric Grid* regarding various aspects of the 100% renewable resource plans.

The Companies performed a high-level, directional analysis of annual energy demand on both islands under each IRP Scenario. The Companies found that more in-depth study would be required to refine the various resource capacity requirements, more accurately evaluate potential curtailment issues, and to assess the feasibility of operating the system given the various resources in each plan.

The Companies used the current generation resources (see "Lanai Utility-Owned Generation" and "Molokai Utility-Owned Generation" on page 8-12) and fuel to define the Status Quo resource plan. Minimum firm generation assumptions applied to all the resource plans accounted for maintaining system reliability.

For Lanai, all resource plans include one baseloaded CAT unit running at minimum load at the Miki Basin Power Plant. In addition, the Manele CHP and the existing LSR 1.2 MW PV farm were assumed to continue full operation in all resource plans. For Molokai, all resource plans include two baseloaded CAT units running at minimum load at the Paalau Power Plant.

The Companies included a 10 MW/15 MWh battery in all resource plans that added non-firm renewable resources. The battery maximizes the useful energy from the non-firm resources by storing excess energy rather than curtailed. Table 8-6 summarizes the resource plans evaluated for both islands.

Table 8-6. Lanai and Molokai Resource Plan Summary

Strategy	Wind	Wave	Biomass	Utility-Scale PV	Biodiesel	Battery	LNG	ULSD
Status Quo	–	–	–	–	–	–	–	100%
100% Renewable, Mixed	x	x	x	–	x	x	–	–
100% Renewable, Biodiesel	–	–	–	–	x	–	–	–
100% Renewable, Wind, and Biodiesel	x	–	–	–	x	x	–	–
100% Renewable, Wave, and Biodiesel	–	x	–	–	x	x	–	–
100% Renewable, Biomass, and Biodiesel	–	–	x	–	x	–	–	–
100% Renewable, PV, and Biodiesel	–	–	–	x	x	x	–	–
LNG	–	–	–	–	–	–	50%	50%
LNG + Renewable, Wind	x	–	–	–	–	x	50%	50%
LNG + Renewable, Biomass	–	–	x	–	–	–	50%	50%

General Conclusions

Based on our analysis, these resources can potentially lower costs for Lanai and Molokai as compared to the status quo plan:

- LNG
- Biomass (if a sufficient feedstock resource can be identified)
- Utility-scale solar PV with battery storage

Understanding the Resource Plan Sheets

To conduct our analysis, the Companies created color-coded resource plan sheets that explain each resource plan. These explanation contain myriad date the describes the resource plan, the actions taken over a 20-year planning period, and a summary of the costs and a ranking.

Here is the legend for understanding the resource plan sheets.

Explanation of Data

Each resource plan sheet can contain this data (which is always listed down the first column):

Name	The technical mnemonic name of the resource plan. All names begin with a letter for the utility followed by a number representing a scenario: P = Hawaiian Electric H = HELCO M = MECO; MM = Molokai; ML = Lanai 1 = Blazing a Bold Frontier 2 = Stuck in the Middle 3 = No Burning Desire 4 = Moved by Passion The rest of the name contains mnemonics that represent various components in the resource plan.
Plan	A description of the resource plan
Notes	Additional plan assumptions
Resources Available	Resource name and first year available in the Strategist model
Years	From 2014–2033, a listing of the actions used to analyze this resource plan
Strategist PV Planning Period Total Cost	Present value of the 20-year planning period cost from the Strategist model
Strategist PV Study Period Total Cost	Present value of the 50-year study period cost from the Strategist model
PV Planning Period Total Cost	Present value of the 20-year planning period cost from both the Strategist model and outside the model revenue requirements
PV Study Period Total Cost	Present value of the 50-year study period cost from both the Strategist model and outside the model revenue requirements
Planning Rank	Ranking by present value Planning Period cost
Study Rank	Ranking by present value Study Period cost

Color Coding Legend

Most of the cells that describe an action are color-coded.

Table 8-7. Resource Plan Sheet Color Coding Legend

Color	Explanation
Tan	Scenario Assumptions for DR
Beige	Scenario Assumptions for DSM
Green	Renewable Resource Addition
Purple	Fuel Switch or AQC Installation
Red	Unit Deactivation
Cyan	Unit Switch from Baseload to Cycling
Yellow	Conventional Resource Addition
Light Green	Lanai Wind Transaction

See Table 8-8 for a sample resource plan sheet and *Appendix O: Resource Plan Sheets* for every resource plan.

Demand Response

The Companies conducts an analysis of using a Demand Response (DR) strategy to control customer's loads and accommodate additional renewable energy. The PBFA Demand-Side Management (DSM) Programs section (page7-32) evaluates these programs and provides an analysis of no DR program and the new Hawaiian Electric, HELCO, and MECO DR programs. For additional discussion and analysis of DR, see *Chapter 12: Smart Grid Implementation Analysis* and *Chapter 13: Essential Grid Ancillary Services Analysis*.

The Demand Response (DR) programs described in *Appendix F: DR and DSM Program Data* were also analyzed for their capacity deferral and ancillary services benefits. *Appendix O: Resource Plan Sheets* contains the resource plans with different DR programs levels.

Hawaiian Electric Demand Response Analysis

Demand Response Capacity Deferral

One of the major benefits of DR programs is its ability to defer the need for generating capacity on the system. The Companies analyzed the impact of the potential deferral benefit between the two Hawaiian Electric DR programs levels for each of the four scenarios: Continue Existing DR and Expanded DR. The Companies made resource timing runs to analyze the differences between the two programs.

For futures where loads are decreasing loads (Blazing a Bold Frontier), the capacity deferral value of DR programs are not realized because new generating capacity is not required in a declining load situation. Even if capacity need is triggered by the retirement of existing DR programs, it might not have any capacity deferral value because of their size. This is the case for the two levels of DR programs evaluated. As shown in Table 8-8, the Expanded DR program does not defer the 2020 addition of a Simple Cycle Combustion Turbine (SCCT) triggered by the deactivation of Waiau 3 and 4 and Honolulu 8 and 9.

Table 8-8. HECO Blazing a Bold Frontier No Capacity Deferral Value of DR

Name	**P1_2a1XRetire-1r0**	**P1_2a1NRetire-1r0**
Plan	Continue Existing Timing w/ H89 W34 Ret(ICE, SCCT)	Expanded DR Timing w/ H89 W34 Ret (ICE, SCCT)
Notes		All ICE & CTs available; 2017 ULSD switch
Resources Available	ICE (17 MW); Biodiesel (PS01): 2018 42 MW SCCT LM6000; Biodiesel (PS06): 2018 100 MW SCCT LMS100; Biodiesel (PS07): 2018 59 MW 1on1 LM6000 CC; Biodiesel (PC08): 2018 9.6 MW OTEC (PO01): 2018 25 MW Banagrass Combustion (PA01): 2018	ICE (17 MW); Biodiesel (PS01): 2018 42 MW SCCT LM6000; Biodiesel (PS06): 2018 100 MW SCCT LMS100; Biodiesel (PS07): 2018
2014	Continue CIDLC, CIDP, RDLCWH, RDLCAC	Expanded CIDLC, CIDP, RDLCWH, RDLCAC
	75%+25%+10% PBFA DSM	75%+25%+10% PBFA DSM
2015		
2016	Fuel switch to diesel (Honolulu 8–9; Waiau 5–8; Kahe 1–6)	Fuel switch to diesel (Honolulu 8–9; Waiau 5–8; Kahe 1–6)
2017	Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW) or Deactivate Honolulu 8/9	Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW) or Deactivate Honolulu 8/9
2018		
2019	Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW) or Deactivate Waiau 3/4	Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW) or Deactivate Waiau 3/4
2020	Add 91MW SCCT (PS07x1); biofuel	Add 91MW SCCT (PS07x1); biofuel
2021		
2022	Fuel switch to diesel (Honolulu 8–9, Waiau 5–8, Kahe 1–6)	Fuel switch to diesel (Honolulu 8–9, Waiau 5–8, Kahe 1–6)
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
Planning Period Total Cost	33,130,600	33,217,246
Study Period Total Cost	45,362,256	45,480,256
Planning Rank	1	2
Study Rank	1	2

In futures where the load increases, the expanded DR programs defer the need for generation capacity. For Stuck in the Middle, the 2021 91 MW SCCT is deferred beyond 2033 with the implementation of the Expanded DR programs (Table 8-9). This capacity deferral value results in a lower overall study and planning period costs and an estimated lower Residential Rate.

Table 8-9. HECO Stuck in the Middle Capacity Deferral Value of DR

Name	**P2_2a1XRetire-1r0**	**P2_2a1NRetire-1r0**
Plan	Firm Timing with Conventional, Continue Existing DR	Firm timing w/ Expanded DR
Notes	Waiau 3/4 and Honolulu 8/9 deactivated	Waiau 3/4 and Honolulu 8/9 deactivated
Resources Available	91 MW SCCT LMS100; Biodiesel (PS07): 2019 25 MW Biomass-Banagrass (PA01): 2019 59 MW CC-Biodiesel (PC08): 2019 9.6 MW OTEC (POT1): 2019	91 MW SCCT LMS100; Biodiesel (PS07): 2019 25 MW Biomass-Banagrass (PA01): 2019 59 MW CC-Biodiesel (PC08): 2019 9.6 MW OTEC (POT1): 2019
2013	HPower expansion (27 MW)	HPower expansion (27 MW)
	Airport DSG (8 MW)	Airport DSG (8 MW)
2014	Continue CIDLC, CIDP, RDLCWH, RDLCAC	Expanded CIDLC, CIDP, RDLCWH, RDLCAC
	75% PBFA DSM	75% PBFA DSM
2015		
2016	Fuel switch to diesel (Honolulu 8–9, Waiau 5–8, Kahe 1–6)	Fuel switch to diesel (Honolulu 8–9, Waiau 5–8, Kahe 1–6)
2017	Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW) or Honolulu 8/9	Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW) or Honolulu 8/9
2018		
2019	Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW) or Waiau 3/4	Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW) or Waiau 3/4
2020	Add 91MW SCCT (PS07x1); biofuel	Add 91MW SCCT (PS07x1); biofuel
2021	Add 91MW SCCT (PS07x1); biofuel	
2022	Fuel switch to diesel (Honolulu 8–9, Waiau 5–8, Kahe 1–6)	Fuel switch to diesel (Honolulu 8–9, Waiau 5–8, Kahe 1–6)
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		

Name	P2_2a1XRetire-1r0	P2_2a1NRetire-1r0
Planning Period Total Cost	22,786,490	22,685,522
Study Period Total Cost	34,706,916	34,647,932
Planning Rank	2	1
Study Rank	2	1

Figure 8-3 and Figure 8-4 show the estimated Residential Rates for the Continue DR plan (P1_2a1XRetire-1r0) and the Expand DR plan (P1_2a1NRetire-1r0). The difference in rates is relatively small, but the Expand DR plan is about 0.26¢/kWh lower on average over the 20 planning period.

Figure 8-3. HECO Stuck in the Middle Residential Rate for DR

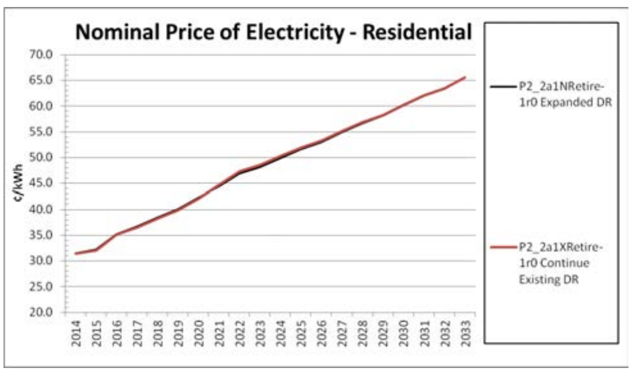
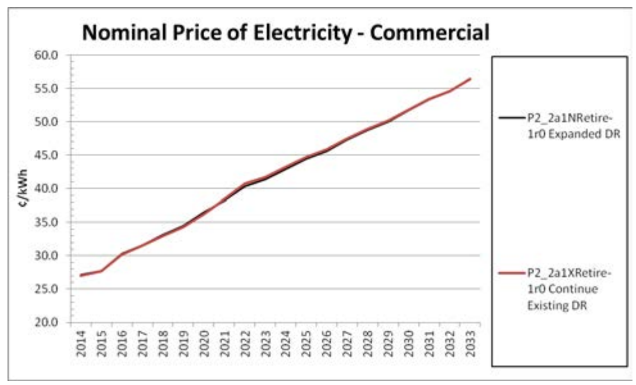


Figure 8-4. HECO Stuck in the Middle Commercial Rate for DR



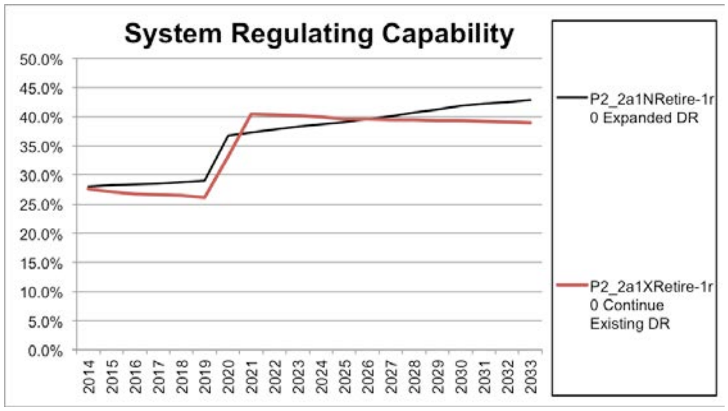
Another benefit of implementing an Expanded DR program is that it would increase the amount of regulating capability (Figure 8-5) of the system to respond to the variable output of renewable energy[44]. This would help with integrating large amounts of non-firm variable renewable energy into the grid. This is discussed further in Costs and Benefits of Smart Grids (page 12-8).

The results of the analysis that compares the two DR program levels for No Burning Desire and Moved by Passion produced similar results.[45]

[44] Regulating Capability is higher in 2021 for plan with Continue DR because of contribution to regulating reserve from the 91 MW SCCT unit added in 2021.

[45] See Plans "P3_2a1XRetire-1r0 Timing" versus "P3_2a1NRetire-1r0 Timing" and Plans "P4_2a1XRetire-1r0" versus "P4_2a1NRetire-1r1".

Figure 8-5. HECO Stuck in the Middle System Regulating Capability Comparison of DR Programs



Demand Response Ancillary Services

The Companies also analyzed how ancillary services that DR can provide in the form of spinning reserve. The Companies ran models using a resource plan containing new wind, PV, a biofuel combined cycle plant, and a 25 MW biomass steam plant resources with the Expanded DR program. In the plan P2B2b1NRetire-2r0, the Expanded DR program was characterized with no spinning reserve value for any of the DR programs while in the plan P2B2b1NRetire-9r1, a percentage of the program's coincident peak capacity was used to reduce the spinning reserve requirements of the system (using 55% of the Commercial and Industrial Direct Load Control (CIDLC) program impact, 50% of Commercial and Industrial Dynamic Pricing (CIDP) program impact, and 100% of the Residential Direct Load Control Water Heater (RDLCWH) program impact).

The analysis shows that the spinning reserve contribution from the DR programs lowers Total Resource Cost (Table 8-10).

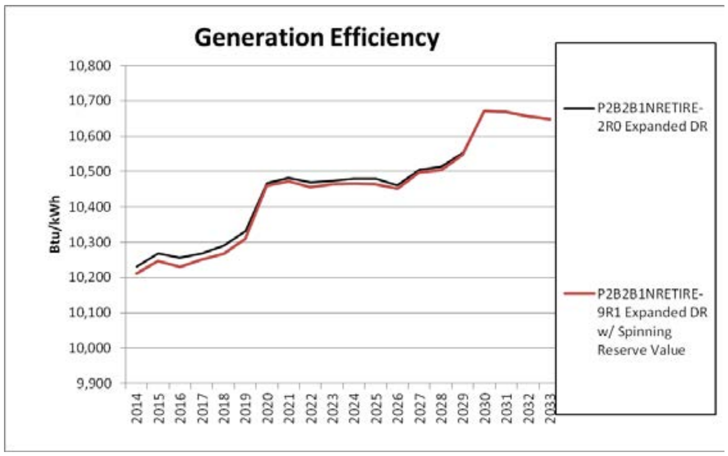
Table 8-10. HECO Evaluation of the Spinning Reserve Benefit of DR Programs

Name	**P2B2b1NRetire-2r0**	**P2B2b1NRetire-9r1**
Plan	DR with No Spin Value	DR with Spinning Reserve Value
Notes		Spinning Contribution: 55% for CIDLC, 50% For CIDP, 100% for RDLCWH
Resources Available	None	None
2014	Expanded CIDLC, CIDP, RDLCWH, RDLCAC	Expanded CIDLC, CIDP, RDLCWH, RDLCAC
	75% PBFA DSM	75% PBFA DSM
2015		
2016	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)
	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)
	Fuel switch to diesel (Honolulu 8–9, Waiau 5–8, Kahe 1–6)	Fuel switch to diesel (Honolulu 8–9, Waiau 5–8, Kahe 1–6)
2017	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)
	Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW) or Honolulu 8/9	Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW) or Honolulu 8/9
2018	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)
2019	Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW) or Waiau 3/4	Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW) or Waiau 3/4
2020	Add 59MW CC (PC08x1); biofuel	Add 59MW CC (PC08x1); biofuel
	Add 200 MW Lanai Wind	Add 200 MW Lanai Wind
2021		
2022	Fuel switch to ULSD (Waiau 5-8, Kahe 1-6)	Fuel switch to ULSD (Waiau 5-8, Kahe 1-6)
2023		
2024		
2025		
2026		
2027	Add 25MW (PA01x1); biomass	Add 25MW (PA01x1); biomass
2028	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)
2029	Add 30 MW wind (PW01x1)	Add 30 MW wind (PW01x1)
	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)
2030	Add 150 MW wind (PW01x5)	Add 150 MW wind (PW01x5)
	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)
2031		
2032		
2033		
Planning Period Total Cost	22,369,115	22,354,143
Study Period Total Cost	33,034,979	33,017,997

Name	P2B2b1NRetire-2r0	P2B2b1NRetire-9r1
Planning Rank	2	1
Study Rank	2	1

As expected, the savings is due to improved system operating efficiency and lower system heat rate. DR contributes to the spinning reserve requirement which normally would be met by thermal generating units operating at a lower output level or lower efficiency point. Figure 8-6 depicts this heat rate difference.

Figure 8-6. HECO System Efficiency Effect, Heat Rate, Due to Spinning Reserve Contribution of DR Programs



HELCO Demand Response Analysis

Similar to the Hawaiian Electric results, DR has no capacity deferral value when loads are decreasing. Table 8-11 shows the results of modeling runs that show no capacity deferral value in Blazing a Bold Frontier. The Companies also analyzed two resource plans, one with Hu Honua added in 2014 and one without Hu Honua, to determine the capacity value of implementing new HELCO DR programs.

Table 8-11. HELCO Blazing a Bold Frontier No Capacity Deferral Value of DR With and Without Hu Honua

Name	H1_2A_X-1r0	H1_2A_N-1r0	H1_2B_X-1r0	H1_2B_N-1R0
Plan	Firm Timing With No Resources Added	Firm Timing With No Resources Added	Firm Timing With No Resources Added	Firm Timing With No Resources Added
Notes	Timing Run with No Firm Units Available No DR Programs Shipman 3 & 4 Deactivation	Timing Run with No Firm Units Available New DR Programs Added Shipman 3 & 4 Deactivation	Timing Run with No Firm Units Available No DR Programs Hu Honua Out	Timing Run with No Firm Units Available New DR Programs Added Hu Honua Out
Resources Available	None	None	None	None
2013				
2014		New CIDLC, Fast DR, RDLCWH, RDLCAC		New CIDLC, Fast DR, RDLCWH, RDLCAC
	75%+25%+10% PBFA DSM	75%+25%+10% PBFA DSM	75%+25%+10% PBFA DSM	75%+25%+10% PBFA DSM
	Hu Honua (21.5MW)	Hu Honua (21.5MW)		
2015	Deactivate Shipman 3 (–6.8 MW)	Deactivate Shipman 3 (–6.8 MW)		
	Deactivate Shipman 4 (–6.7 MW)	Deactivate Shipman 4 (–6.7 MW)		
2016				
2017				
2018				
2019				
2020				
2021				
2022				
2023				
2024				
2025				
2026				
2027				
2028				
2029				
2030				

Name	H1_2A_X-1r0	H1_2A_N-1r0	H1_2B_X-1r0	H1_2B_N-1R0
2031				
2032				
2033				
Planning Period Total Cost	4,638,778	4,656,478	5,143,981	5,161,679
Study Period Total Cost	6,536,152	6,563,201	7,291,440	7,318,490
Planning Rank	1	2	1	2
Study Rank	1	2	1	2

Demand Response Capacity Deferral

Similar to the Hawaiian Electric Analysis, the new HELCO DR programs defer the need for generation capacity when capacity is needed for scenarios where load increases. Table 8-12 shows the capacity deferral value of new HELCO DR programs in the highest load growth scenario, No Burning Desire.

The 21 MW Simple Cycle Combustion Turbine (SCCT) unit that is needed in 2023 in the plan H3_2B_X-1Ar0, with no DR program, is deferred by one year to 2023 and replaced by a smaller 17 MW Internal Combustion (ICE) unit as shown in the plan H3_2B_N-1AR0, which includes new HELCO DR programs. New capacity is not needed in No Burning Desire or Moved by Passion, so no deferral value due to new DR programs was realized.

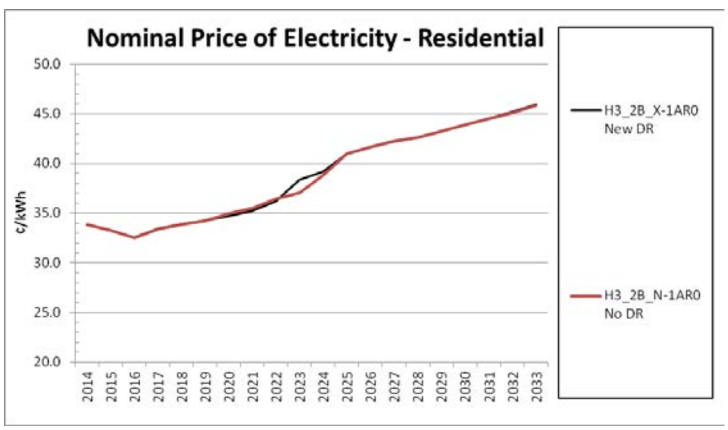
Table 8-12. HELCO No Burning Desire Capacity Deferral Value of New DR Programs in High Load Growth

Name	H3_2B_X-1Ar0	H3_2B_N-1AR0
Plan	Firm Timing With Conventional	Firm Timing With Conventional
Notes	Timing Run with Firm Conventional Units Available No DR Programs Hu Honua Out	Timing Run with Firm Conventional Units Available New DR Programs Added Hu Honua Out
Resources Available	17MW ICE (HS01): 2016 21MW CT (HS05): 2017 42MW CT (HS06): 2017	17MW ICE (HS01): 2016 21MW CT (HS05): 2017 42MW CT (HS06): 2017
2014		New CIDLC, Fast DR, RDLCWH, RDLCAC
	75%+25%+10% PBFA DSM	75%+25%+10% PBFA DSM
2015		
2016		
2017	Add 17MW ICE (HS01x1); biofuel	Add 17MW ICE (HS01x1); biofuel
2018		
2019		
2020		
2021		

Name	H3_2B_X-1Ar0	H3_2B_N-1AR0
2022		
2023	Add 21MW CT (HS05x1); biofuel	
2024		Add 17MW ICE (HS01x1); biofuel
2025	Add 17MW ICE (HS01x1); biofuel	Add 17MW ICE (HS01x1); biofuel
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
Planning Period Total Cost	3,990,766	3,989,072
Study Period Total Cost	5,963,627	5,949,114
Planning Rank	2	1
Study Rank	2	1

Although the capacity deferral value results in a lower overall study and planning period costs, the difference in Residential rates varies slightly. Figure 8-7 shows the estimated Residential Rates for the No DR plan (H2_2B-X-1Ar0) and the New DR programs plan (H3_2B_N-1AR0).

Figure 8-7. HELCO No Burning Desire Residential Rate Comparison for DR



Demand Response Ancillary Services

The Companies also analyzed the potential ancillary services that DR can provide in spinning reserve on a simplified basis. Modeling runs used a resource plan containing new wind, PV, and geothermal plants with the new HELCO DR programs.

In the plan H2B2a_X-2Ar3, the New DR program was characterized with no spinning reserve value for any of the DR programs while in the plan H2B2a_X-2Ar2, a percentage of the program's coincident peak capacity was used to reduce the spinning reserve requirements of the system (using 55% of the Commercial and Industrial Direct Load Control (CIDLC) program impact, 100% of Fast Demand Response (Fast DR) program impact, and 100% of the Residential Direct Load Control Water Heater (RDLCWH) program impact).

This modeling analysis does not capture HELCO's reserve requirement which is needed to provide sub-hourly regulating and ramping reserve. To supply this reserve, the resources must be immediately responsive to automatic generation control. DR resources contributing to regulating reserve must respond on each four-second cycle to up and down directions (for demand response, increasing load and decreasing load). The increases and decreases must be predictable and provide a sustained response available all day. Generation resources that supply regulating reserve also supply other critical grid services (such as inertial response, voltage regulation, meet transmission constraints). There are limited time periods where DR could displace generation needed for regulating reserve.

The simplified analysis shows that if DR can contribute to spinning reserve, the contribution from the DR programs lowers total resource cost (Table 8-13).

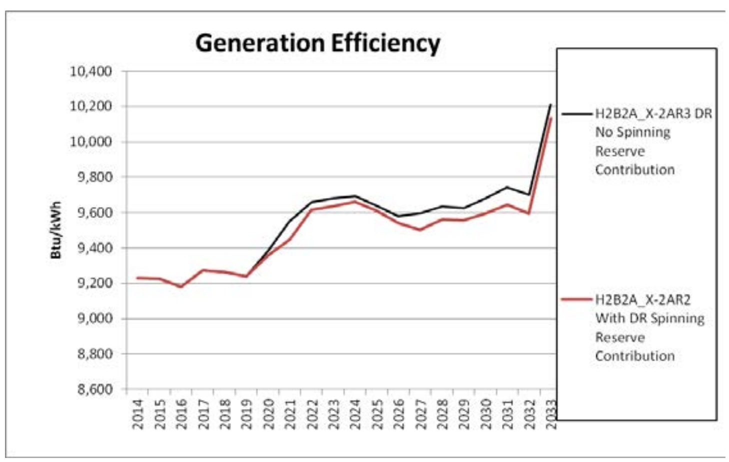
Table 8-13. HELCO Evaluation of the Spinning Reserve Benefit of DR Programs

Name	**H2B2a_X-2Ar3**	**H2B2a_X-2Ar2**
Plan	DR with No Spinning Reserve Contribution	DR with Spinning Reserve Contribution
Notes	Expanded DR added for baseline, Cycle H5/6, Puna	Cycle H5/6, Puna
Resources Available	None	None
2014	New CIDLC, Fast DR, RDLCWH, RDLCAC	New CIDLC, Fast DR, RDLCWH, RDLCAC
	75% PBFA DSM	75% PBFA DSM
	Hu Honua (21.5MW)	Hu Honua (21.5MW)
2015	Deactivate Shipman 3 (–6.8 MW)	Deactivate Shipman 3 (–6.8 MW)
	Deactivate Shipman 4 (–6.7 MW)	Deactivate Shipman 4 (–6.7 MW)
	Add 5MW PV (HP03x5)	Add 5MW PV (HP03x5)
2016		
2017	Add 10MW wind (HW04x1)	Add 10MW wind (HW04x1)
2018		
2019	Add 25MW geothermal (HG01x1)	Add 25MW geothermal (HG01x1)
2020	Add 10MW wind (HW04x1)	Add 10MW wind (HW04x1)
2021		
2022	Add 5MW PV (HP03x5)	Add 5MW PV (HP03x5)
2023	Add 5MW PV (HP03x5)	Add 5MW PV (HP03x5)
2024	Add 5MW PV (HP03x5)	Add 5MW PV (HP03x5)

Name	H2B2a_X-2Ar3	H2B2a_X-2Ar2
2025		
2026		
2027		
2028	Add 5MW PV (HP03x5)	Add 5MW PV (HP03x5)
2029	Add 5MW PV (HP03x5)	Add 5MW PV (HP03x5)
2030	Add 10MW wind (HW04x1)	Add 10MW wind (HW04x1)
2031	Add 10MW wind (HW04x1)	Add 10MW wind (HW04x1)
2032		
2033	Add 25MW geothermal (HG02x1)	Add 25MW geothermal (HG02x1)
	Add 5MW PV (HP03x5)	Add 5MW PV (HP03x5)
Planning Period Total Cost	4,024,851	4,013,741
Study Period Total Cost	5,989,501	5,960,461
Planning Rank	2	1
Study Rank	2	1

As expected, the savings is due to improved system operating efficiency and a lower system heat rate. DR contributes to the spinning reserve requirement which normally would be met by thermal generating units operating at a lower output level or lower efficiency point. Figure 8-8 depicts this heat rate difference.

Figure 8-8. HELCO System Efficiency Effect, Heat Rate, Due to Spinning Reserve Contribution of DR Programs



MECO Demand Response Analysis

Demand Response Deferred Capacity

Similar to the HELCO results, DR has no capacity deferral value when loads are decreasing. Table 8-14 shows the results of modeling runs that show no capacity deferral value in Blazing a Bold Frontier.

Table 8-14. MECO Blazing a Bold Frontier No Capacity Deferral Value of DR

Name	**M1_2b_X-1r3**	**M1_2a_N-1r3**
Plan	HC&S contract continues	HC&S contract terminated 2014
Notes	Unit Timing Rule 1 17MW ICE, 5MW ICE, LM2500, Geo, WTE, Biomass	Unit Timing Rule 1 17MW ICE, 5MW ICE, LM2500, Geo, WTE, Biomass
DR & DSM Assumptions	110% of Base EEPS Fast DR Only	110% of Base EEPS All DR: CIDLC Exp, RDLC Exp, Fast DR
2011–2013	Kaheawa Wind II (21 MW) Auwahi (21 MW)	Kaheawa Wind II (21 MW) Auwahi (21 MW)
2014		
2015		
2016		
2017		
2018		
2019		
2020		
2021		
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
Planning Total Cost	5,848,294.50	6,022,616.00
Study Total Cost	8,130,334.50	8,349,251.50
Planning Rank	1	2

Name	M1_2b_X-1r3	M1_2a_N-1r3
Study Rank	1	2

Similar to the HELCO and Hawaiian Electric analysis, the new MECO DR programs defer the need for generation capacity in scenarios where load increases thus triggering the need for capacity. Table 8-15 shows the capacity deferral value of new MECO DR programs in the highest load growth scenario, No Burning Desire where several 17 MW ICE units are deferred. Similar capacity deferral value was found in Stuck in the Middle (resource plan M2_2__X-1r0 versus plan M2_2__N-1r2). New capacity is not needed in Moved by Passion, so no deferral value due to new DR programs was realized.

Table 8-15. MECO No Burning Desire Capacity Deferral Value of new DR Programs in High Load Growth

Name	M3_2__X-1r1	M3_2__N-1r1
Plan	NBD Timing 17 MW ICE No DR	NBD Timing 17 MW ICE
Notes	17 MW ICE Timing on Rule 1, No DR except Fast DR	17 MW ICE Timing on Rule 1
DR & DSM Assumptions	75% of Base EEPS Fast DR Only	75% of Base EEPS All DR: CIDLC Exp, RDLC Exp, Fast DR
2011–2013	Kaheawa Wind II (21 MW)	Kaheawa Wind II (21 MW)
	Auwahi (21 MW)	Auwahi (21 MW)
2014		
2015	(3) 5 MW ICE; biofuel [MS14]	(3) 5 MW ICE; biofuel [MS14]
2016	(1) 17 MW ICE; biofuel [MS01]	(1) 17 MW ICE; biofuel [MS01]
2017		
2018	(1) 17 MW ICE; biofuel [MS01]	(1) 17 MW ICE; biofuel [MS01]
2019		
2020	(1) 17 MW ICE; biofuel [MS01]	(1) 17 MW ICE; biofuel [MS01]
2021		
2022	(1) 17 MW ICE; biofuel [MS01]	
2023		(1) 17 MW ICE; biofuel [MS01]
2024	(1) 17 MW ICE; biofuel [MS01]	
2025		
2026		(1) 17 MW ICE; biofuel [MS01]
2027	(1) 17 MW ICE; biofuel [MS01]	
2028		(1) 17 MW ICE; biofuel [MS01]
2029	(1) 17 MW ICE; biofuel [MS01]	
2030		
2031		(1) 17 MW ICE; biofuel [MS01]
2032	(1) 17 MW ICE; biofuel [MS01]	
2033		
Planning Total Cost	5,071,778.50	5,050,647.50

Name	M3_2__X-1r1	M3_2__N-1r1
Study Total Cost	7,572,211.00	7,515,388.50
Planning Rank	2	1
Study Rank	2	1

Although the capacity deferral value results in a lower overall study and planning period costs, the difference in Residential rates varies slightly. Figure 8-9 and Figure 8-10 show the estimated Residential Rates for the Fast DR plan (M3_2__X-1r1) and the New DR programs plan (M3_2__N-1r1).

Figure 8-9. MECO No Burning Desire Residential Rate for DR

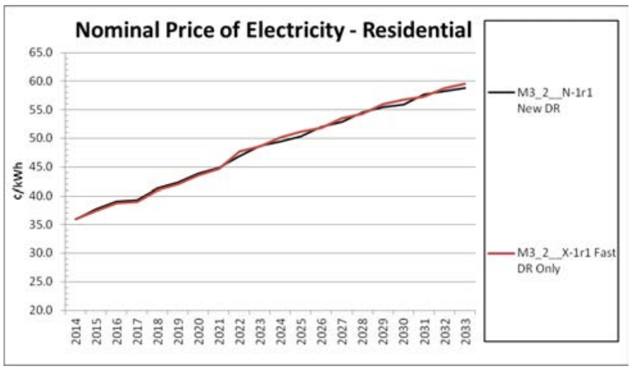
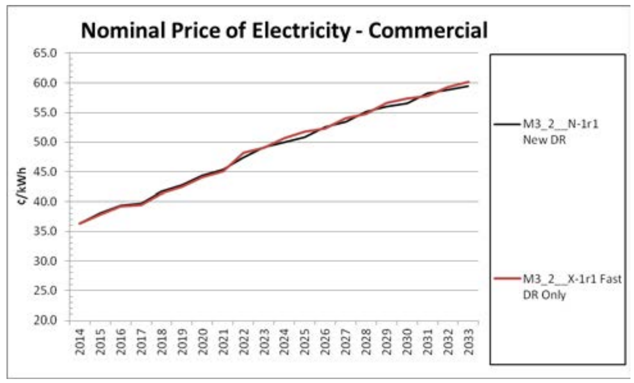
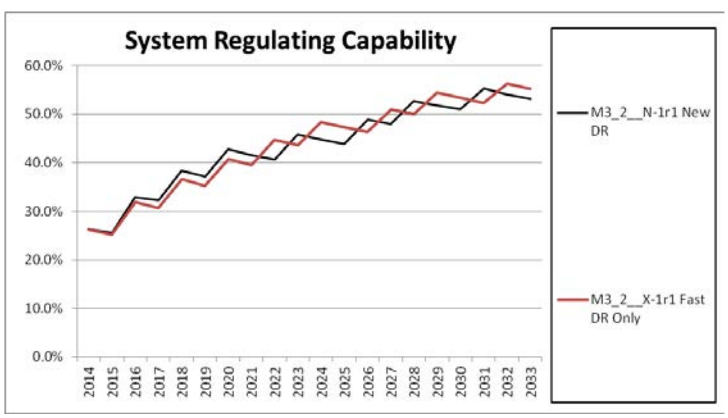


Figure 8-10. MECO No Burning Desire Commercial Rate for DR



Another benefit of implementing new DR programs is that it would increase the amount of regulating capability (see years 2014 to 2021 in Figure 8-11) of the system to respond to the variable output of renewable energy[46]. This would help with integrating large amounts of non-firm variable renewable energy into the grid. This is discussed further in Costs and Benefits of Smart Grids (page 12-8).

Figure 8-11. MECO Stuck in the Middle System Regulating Capability Comparison between DR Programs



46 Regulating Capability is also provided by the contributions of the 17 MW ICE units added in 2022 to 2028 so the results are varied in this period.

Demand Response Ancillary Services

The Companies also analyzed the ancillary services that DR can provide in spinning reserve. Modeling runs used a resource plan containing new wind, PV, and Internal Combustion Engine (ICE) plants with the new MECO DR programs. In the plan M2_2__N-2r17 No Spin. The New DR programs were characterized with no spinning reserve value for any of the DR programs while in the plan M2_2__N-2r17, a percentage of the coincident peak capacity was used to reduce the spinning reserve requirements of the system (using 55% of the Commercial and Industrial Direct Load Control (CIDLC) program impact, 100% of Fast Demand Response (Fast DR) program impact, and 100% of the Residential Direct Load Control Water Heater (RDLCWH) program impact).

The analysis shows that the spinning reserve contribution from the DR programs lowers total resource cost (Table 8-16).

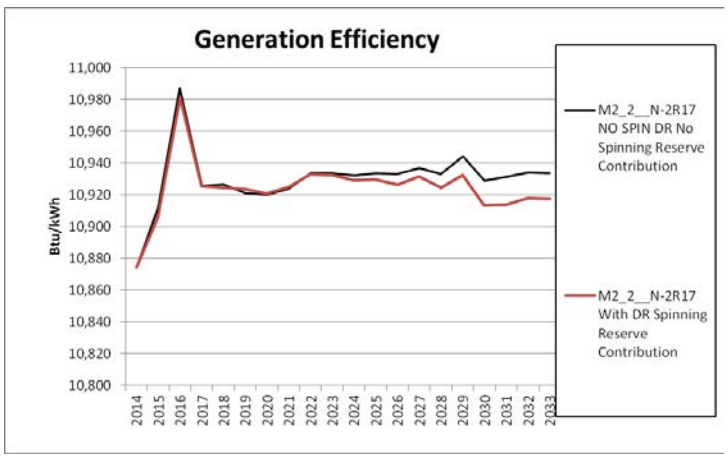
Table 8-16. HELCO Spinning Reserve Benefit Evaluation of DR Programs

Name	**M2_2__N-2r17 No Spin**	**M2_2__N-2r17**
Plan	SitM Screen Fix 5 MW ICE in 2029	SitM Screen Fix 5 MW ICE in 2029
Notes	No Spin Contribution from DR Programs New ICE (5 MW): 2029 fixed, Fix limited WindC7, TrPV	Apply Spin to DR Programs New ICE (5 MW): 2029 fixed, Fix limited Wind C7, TrPV
Resources Available	None	None
DR & DSM Assumptions	75% of Base EEPS All DR: CIDLC Exp, RDLC Exp, Fast DR	75% of Base EEPS All DR: CIDLC Exp, RDLC Exp, Fast DR
2014		
2015	3x Onshore Wind Class 7 (10 MW)	3x Onshore Wind Class 7 (10 MW)
2016	3x Onshore Wind Class 7 (10 MW)	3x Onshore Wind Class 7 (10 MW)
2017	3x Onshore Wind Class 7 (10 MW)	3x Onshore Wind Class 7 (10 MW)
2018		
2019		
2020		
2021		
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029	ICE biofuel (5 MW)	ICE biofuel (5 MW)
2030	5x Tracking PV (1 MW)	5x Tracking PV (1 MW)
2031		

Name	M2_2__N-2r17 No Spin	M2_2__N-2r17
2032		
2033		
Planning Total Cost	4,178,033.20	3,968,782.80
Study Total Cost	6,209,654.00	5,923,331.50
Planning Rank	#n/a	#n/a
Study Rank	#n/a	#n/a

As expected, the savings is due to improved system operating efficiency and a lower system heat rate. DR contributes to the spinning reserve requirement which normally would be met by thermal generating units operating at a lower output level or lower efficiency point. Figure 8-12 depicts this heat rate difference.

Figure 8-12. MECO System Efficiency Effect, Heat Rate, Due to Spinning Reserve Contribution of DR Programs



Replacing Fossil Fuel Plants with Renewable Energy Resources

Replacing existing fossil fuel units with renewable energy resources in plans that retired existing units, and in plans that achieved 100% renewable energy by 2030 was evaluated in all four scenarios. The results involving retirement and replacement with new generation are further discussed in Complying with Environmental Standards (page 9-18) where the retirement strategy was assessed as an environmental compliance strategy.

The 100% renewable energy plans involving conversion of any existing units remaining in service to biofuels by 2030are the highest cost in most scenarios. The results for Stuck in the Middle are discussed in RPS Rate Impact (page 8-50).

Geothermal, Waste-to-Energy, and Battery Storage

Hawaiian Electric. The Companies did not analyze geothermal options on Oahu because the island does not have any known geothermal resources. The Companies also did not analyze additional waste-to-energy facilities on Oahu because the existing waste-to-energy facility, HPower, was recently expanded. In *Chapter 11: Inter-Island and Inter-Utility Connection Analysis*, the Companies did analyze geothermal power delivered to Oahu primarily from geothermal units located on the island of Hawaii and as a resource option on Maui.

MECO. The Companies analyzed geothermal and waste-to-energy resources for Maui for both firm timing and screening of resources. Plans were allowed to add up to 50 MW of geothermal and 8 MW of waste-to-energy. Geothermal can be a cost effective resource to add for firm capacity needs and to reduce cost (see resource plans M2_2__X-1r2, M3_2__N-1r4, run M4_2a_X-1r0). The model did not choose waste-to-energy as a cost effective resource.

The Companies also analyzed battery storage on the MECO system to demonstrate system benefits when a battery storage resource is added (Battery Storage Analysis, page 8-48).

Battery Storage Analysis

Our analysis (for Stuck in the Middle) addressed whether battery storage technologies could decrease reliance on fossil-fuel generation resources, provide essential grid ancillary services, and accommodate expected increasing proportions of variable and intermittent renewable generation resources.

Results showed that a 15 MWh battery storage resource reduced the amount of curtailed renewable energy by almost 2 GWh per year (Figure 8-13). By reducing curtailment, the amount of renewable energy increased, thus increasing the RPS percentage slightly (Figure 8-14).

Figure 8-13. Renewable Energy Curtailed through Battery Storage

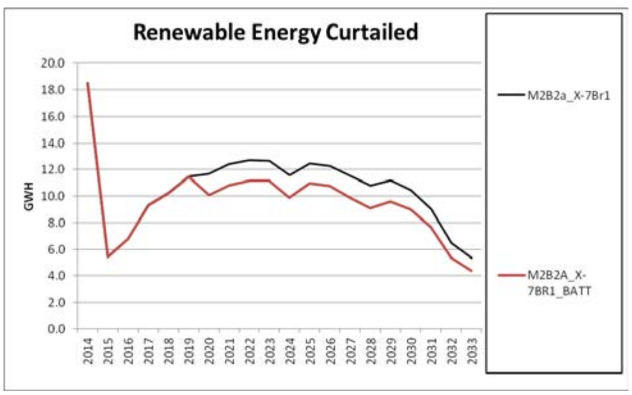
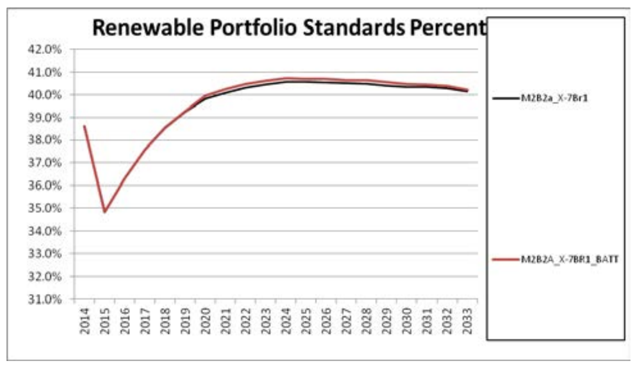


Figure 8-14. RPS Percent through Battery Storage



Although the amount of renewables increased, the plan costs were higher due to capital and fixed O&M costs for battery storage. To increase renewable energy on Maui, a more cost effective alternative might be increasing the amount of renewables during the on-peak periods, where curtailment wouldn't be increased.

These resource plans are shown in Table 8-17.

Table 8-17. Battery Storage Resource Plan Sheet

Name	M2B2a_X-7Br1	M2B2a_X-7Br1_Batt	M2B2a_X-7Br1_PV
Plan	No Battery	Battery storage forced in 2020	PV forced in 2020
Notes	From EEPS run		
Resources Available		All resources were fixed	All resources were fixed
DR & DSM Assumptions	75% of Base EEPS Fast DR Only	75% of Base EEPS Fast DR Only	75% of Base EEPS Fast DR Only
2014			
2015			

Name	**M2B2a_X-7Br1**	**M2B2a_X-7Br1_Batt**	**M2B2a_X-7Br1_PV**
2016			
2017			
2018			
2019			
2020		Battery storage (MB01)	PV (1 MW)
2021			
2022			
2023	ICE biofuel (17 MW)	ICE biofuel (17 MW)	ICE biofuel (17 MW)
2024			
2025			
2026			
2027			
2028			
2029			
2030			
2031			
2032			
2033			
Planning Total Cost	4,219,083	4,222,622	4,219,248
Study Total Cost	6,394,515	6,398,245	6,393,094
Planning Rank	1	3	2
Study Rank	2	3	1

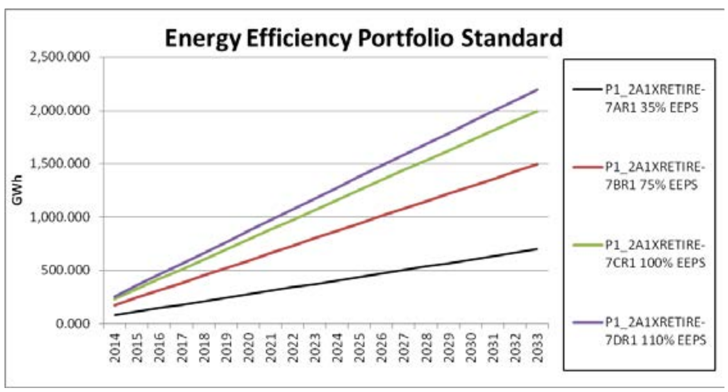
EEPS Rate Impact

The EEPS Rate Impact was analyzed by evaluating the firm resources needed under various levels of energy efficiency for three scenarios: Blazing a Bold Frontier, Stuck in the Middle, and No Burning Desire. The Moved by Passion scenario was not analyzed as it would yield similar results to the Stuck in the Middle scenario. Because this issue was evaluated as a firm capacity timing run, we choose a 17 MW internal combustion unit to determine the years in which there was a capacity need and no variable resources were allowed.

The levels of EEPS analyzed were 35%, 75%, 100%, and 110% of the 4,300 GWh system wide target as stated in the Hawaii Revised Statutes § 269-96, with the total system wide target distributed amongst the islands.

Figure 8-15 shows the EEPS levels for Hawaiian Electric.

Figure 8-15. HECO Blazing a Bold Frontier Levels of EEPS Analyzed



Hawaiian Electric EEPS Rate Impact Analysis

Blazing a Bold Frontier

Under Blazing a Bold Frontier with the declining load, no capacity is needed in all years. Increasing levels of EEPS offset higher cost fuel so the resulting plans with greater levels of EEPS have lower total resource cost (Figure 8-16).

Greater levels of EEPS can lead to greater amounts of curtailment because the resource plan with the highest level of EEPS also has the greatest amount of curtailed energy (Figure 8-17).

Figure 8-16. HECO Blazing a Bold Frontier Amount of Imported Fossil Fuel Oil by Resource Plan

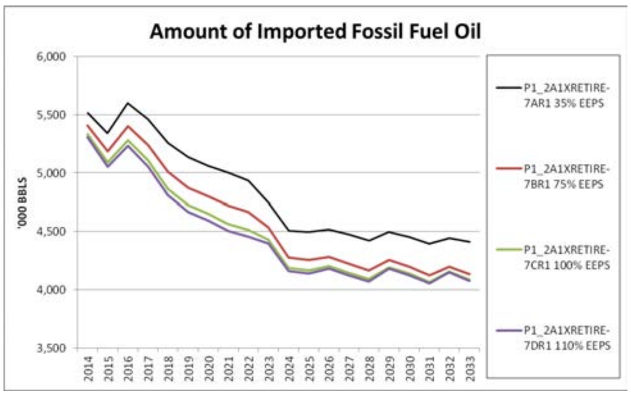
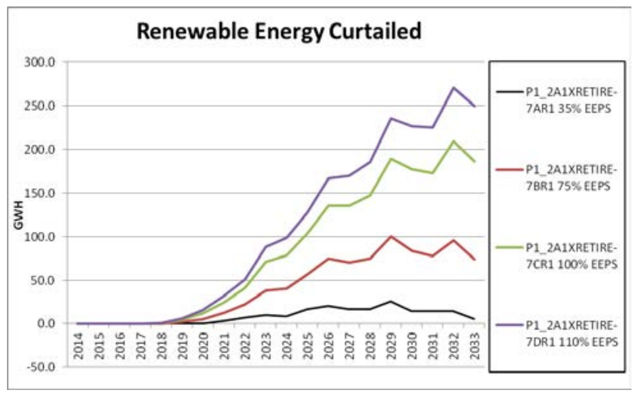


Figure 8-17. HECO Blazing a Bold Frontier Renewable Energy Curtailment



Greater levels of EEPS lowered the total resource cost of the plans. When compared against the nominal price of electricity for residential customers, the rates were highest when the highest level of EEPS was integrated into the system. Even though no new capacity is needed, existing system cost is spread across an increasingly smaller sales base due to the combined effects of increased EEPS and the declining load. This leads to higher residential rates, particularly in later years where sales have decreased significantly. EEPS increases rates by about 21.3¢/kWh in 2033 when comparing the 110% level against the 35% level.

Figure 8-18. HECO Blazing a Bold Frontier Nominal Price of Electricity for Residential Customers

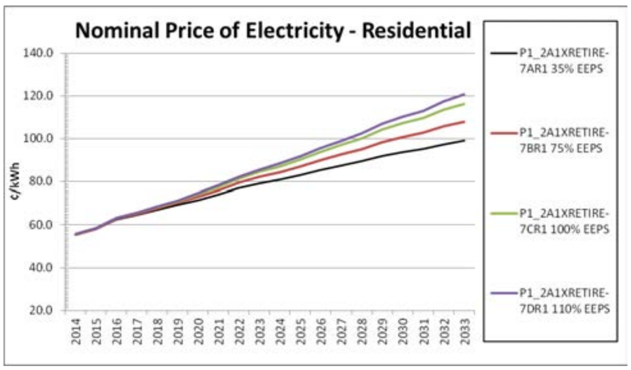
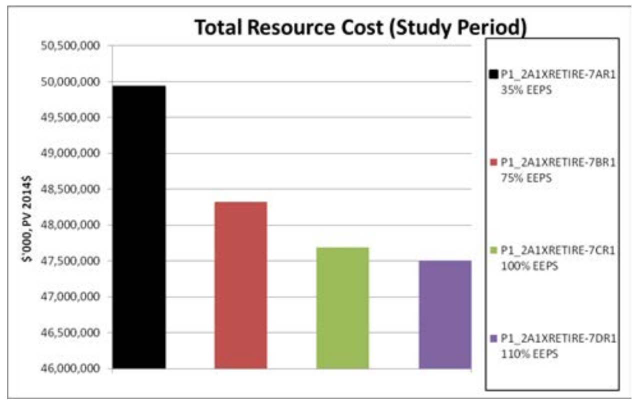


Figure 8-19. HECO Blazing a Bold Frontier Total Resource Cost



Stuck in the Middle

Under Stuck in the Middle, the decrease in load due to EEPS can offset unit additions. The money saved by deferring new units plus the fuel savings leads to lower total resource cost plans as the level of EEPS is increased. The plan metrics capture the capital that is saved by deferring new units to later years and translate that capital into revenue requirements. EEPS increases rates by about 0.5¢/kWh in 2033 when comparing the 110% level against the 35% level despite the capacity deferment.

Figure 8-20. HECO Stuck in the Middle Annual Revenue Requirements for Capital

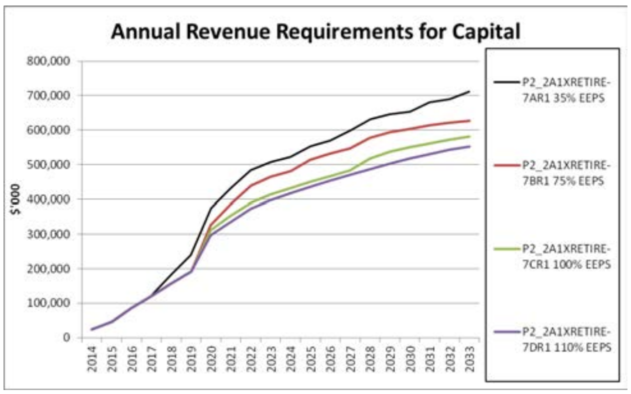


Figure 8-21. HECO Stuck in the Middle Nominal Price of Electricity for Residential Customers

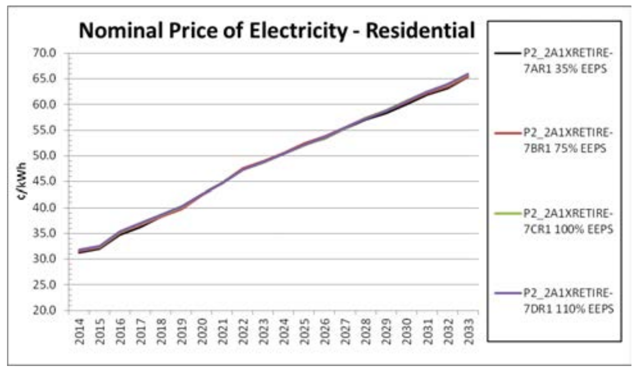


Figure 8-22. HECO Stuck in the Middle Total Resource Cost

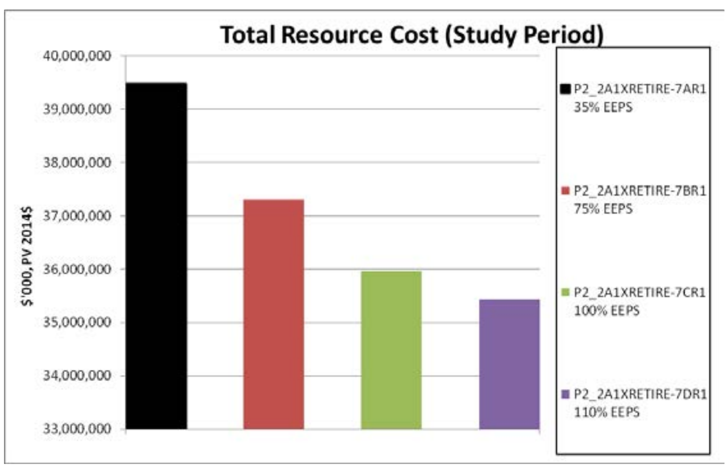


Table 8-18 shows Hawaiian Electric's EEPS resource plans.

Table 8-18. HECO Stuck in the Middle Resource Plans Showing Capacity Deferral

Name	**P2_2a1XRetire-7Ar1**	**P2_2a1XRetire-7Br1**	**P2_2a1XRetire-7Cr1**	**P2_2a1XRetire-7Dr1**
Plan	35%EEPS,w H89 W34 Ret (ICE)	75%EEPS,w H89 W34 Ret (ICE)	100%EEPS,w H89 W34 Ret (ICE)	110%EEPS,w H89 W34 Ret (ICE)
Notes	With transactions	With transactions	With transactions	With transactions
Resources Available		17MW ICE (PS01): 2016	17MW ICE (PS01): 2016	17MW ICE (PS01): 2016
Reference	P2_2a1XRetire-7Ar1.xlxs	P2_2a1XRetire-7Br1.xlxs	P2_2a1XRetire-7Cr1.xlxs	P2_2a1XRetire-7Dr1.xlxs
2014	Continue CIDLC, CIDP, RDLCWH, RDLCAC	Continue CIDLC, CIDP, RDLCWH, RDLCAC	Continue CIDLC, CIDP, RDLCWH, RDLCAC	Continue CIDLC, CIDP, RDLCWH, RDLCAC
	10%+25% PBFA DSM	75% PBFA DSM	25%+75% PBFA DSM	10%+25%+75% PBFA DSM
2015				
2016				
2017	Retire Waiau 3 (–46 MW) Retire Waiau 4 (–46 MW) or Honolulu 8/9	Retire Waiau 3 (–46 MW) Retire Waiau 4 (–46 MW) or Honolulu 8/9	Retire Waiau 3 (–46 MW) Retire Waiau 4 (–46 MW) or Honolulu 8/9	Retire Waiau 3 (–46 MW) Retire Waiau 4 (–46 MW) or Honolulu 8/9
2018	Add 34MW ICE (PS01x2); biofuel			
2019	Add 17MW ICE (PS01x1); biofuel			
	Retire Honolulu 8 (–53 MW) Retire Honolulu 9 (–54 MW) or Waiau 3/4	Retire Honolulu 8 (–53 MW) Retire Honolulu 9 (–54 MW) or Waiau 3/4	Retire Honolulu 8 (–53 MW) Retire Honolulu 9 (–54 MW) or Waiau 3/4	Retire Honolulu 8 (–53 MW) Retire Honolulu 9 (–54 MW) or Waiau 3/4
2020	Add 85MW ICE (PS01x5); biofuel	Add 85MW ICE (PS01x5); biofuel	Add 68MW ICE (PS01x4); biofuel	Add 51MW ICE (PS01x3); biofuel
2021	Add 17MW ICE (PS01x1); biofuel	Add 17MW ICE (PS01x1); biofuel		
2022	Add 34MW ICE (PS01x2); biofuel	Add 34MW ICE (PS01x2); biofuel	Add 17MW ICE (PS01x1); biofuel	Add 17MW ICE (PS01x1); biofuel
2023				
2024				
2025	Add 17MW ICE (PS01x1); biofuel	Add 17MW ICE (PS01x1); biofuel		
2026				
2027	Add 17MW ICE (PS01x1); biofuel			
2028	Add 17MW ICE (PS01x1); biofuel	Add 17MW ICE (PS01x1); biofuel	Add 17MW ICE (PS01x1); biofuel	
2029				
2030				
2031	Add 17MW ICE (PS01x1); biofuel			
2032				

Name	P2_2a1XRetire-7Ar1	P2_2a1XRetire-7Br1	P2_2a1XRetire-7Cr1	P2_2a1XRetire-7Dr1
2033	Add 17MW ICE (PS01x1); biofuel			
Planning Period Total Cost	26,531,824	25,590,375	24,979,776	24,741,929
Study Period Total Cost	39,482,477	37,311,593	35,970,443	35,436,567
Planning Rank	4	3	2	1
Study Rank	4	3	2	1

No Burning Desire

Under No Burning Desire with the highest load growth, greater levels of EEPS continue to defer new units and reduce fuel consumption. EEPS does provide rate savings especially in the later years where new capacity can be deferred and load has grown significantly. In 2033, EEPS can provide a rate savings of about 1.6¢/kWh when comparing the 110% level against the 35% level.

Figure 8-23. HECO No Burning Desire Nominal Price of Electricity for Residential Customers

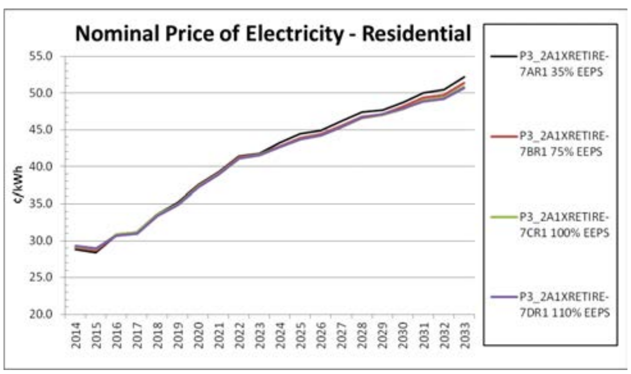
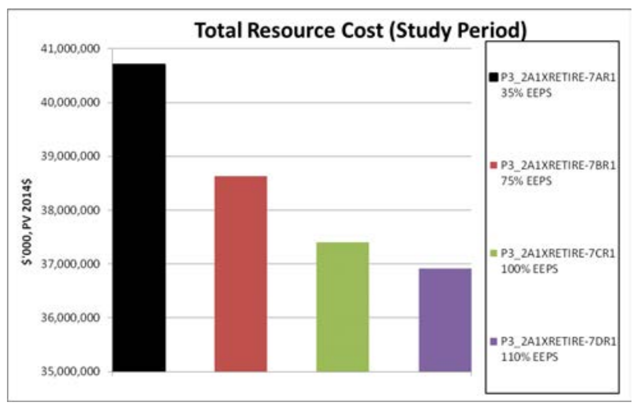


Figure 8-24. HECO No Burning Desire Total Resource Cost



While EEPS can save fuel and capital costs, higher levels of EEPS are best for customers if load grows. If load declines, customers might see rates increase as the EEPS program expands. This analysis also shows that the potential rate increase on a declining sales base is much greater than the potential rate savings on a growing sales base as EEPS levels increase. Therefore, the most appropriate level of EEPS for customers will depend on the current level of sales and future sales trajectory.

HELCO EEPS Rate Impact Analysis

HELCO plans follow a similar trend with increasing levels of EEPS being effective in reducing total resource cost in scenarios with and without load growth. Across the scenarios, HELCO may gain some rate savings while risking a small increase in rates by implementing more EEPS.

Blazing a Bold Frontier

In Blazing a Bold Frontier, rates increase about 4.2¢/kWh in 2033 when comparing the 110% level against the 35% level.

Figure 8-25. HELCO Blazing a Bold Frontier Nominal Price of Electricity for Residential Customers

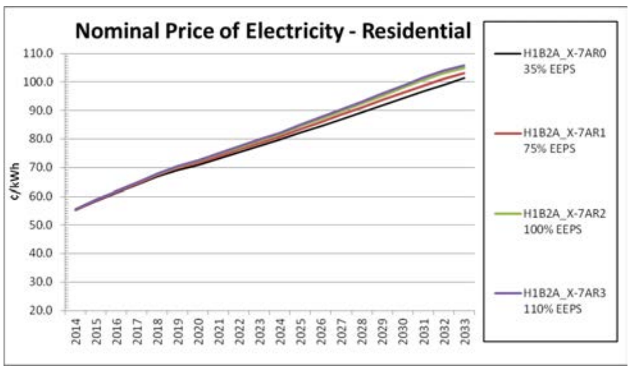
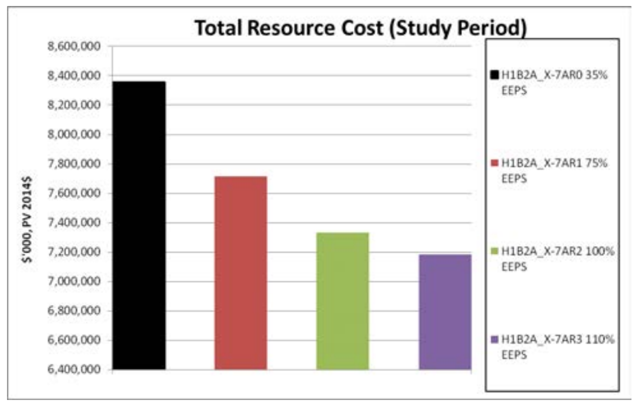


Figure 8-26. HELCO Blazing a Bold Frontier Total Resource Cost



Stuck in the Middle

In Stuck in the Middle, rates increase about 2.2¢/kWh in 2033 when comparing the 110% level against the 35% level. The resource plans show that there is no capacity needed in this scenario after Hu Honua is added in 2014 regardless of the EEPS level, thus no capacity deferral is observed.

Figure 8-27. HELCO Stuck in the Middle Nominal Price of Electricity for Residential Customers

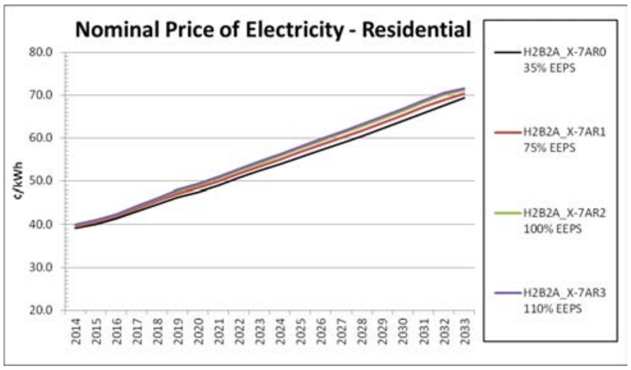


Figure 8-28. HELCO Stuck in the Middle Total Resource Cost

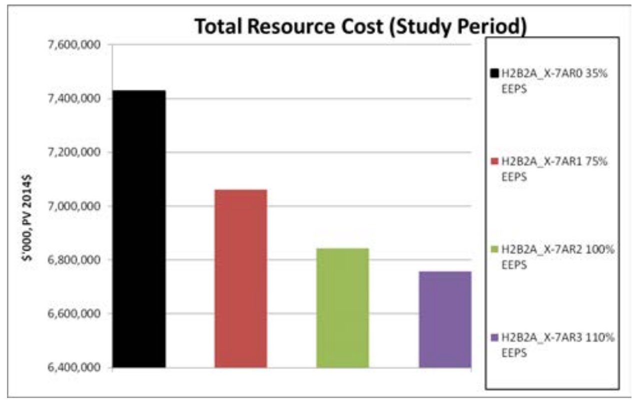


Table 8-19 shows HELCO's EEPS resource plans.

Table 8-19. HELCO Stuck in the Middle Resource Plans

Name	**H2B2a_X-7AR0**	**H2B2a_X-7AR1**	**H2B2a_X-7AR2**	**H2B2a_X-7AR3**
Plan	35% EEPS Timing	75% EEPS Timing	100% EEPS Timing	110% EEPS Timing
Notes	Timing Run with 17MW ICE	Timing Run with 17MW ICE	Timing Run with 17MW ICE	Timing Run with 17MW ICE
Resources Available	None	None	None	None
2013				
2014	25%+10% PBFA DSM	75% PBFA DSM	75%+25% PBFA DSM	75%+25%+10% PBFA DSM
	Hu Honua (21.5MW)	Hu Honua (21.5MW)	Hu Honua (21.5MW)	Hu Honua (21.5MW)
2015	Deactivate Shipman 3 (–6.8 MW)	Deactivate Shipman 3 (–6.8 MW)	Deactivate Shipman 3 (–6.8 MW)	Deactivate Shipman 3 (–6.8 MW)
	Deactivate Shipman 4 (–6.7 MW)	Deactivate Shipman 4 (–6.7 MW)	Deactivate Shipman 4 (–6.7 MW)	Deactivate Shipman 4 (–6.7 MW)
2016				
2017				
2018				
2019				
2020				
2021				
2022				
2023				

Name	H2B2a_X-7AR0	H2B2a_X-7AR1	H2B2a_X-7AR2	H2B2a_X-7AR3
2024				
2025				
2026				
2027				
2028				
2029				
2030				
2031				
2032				
2033				
Planning Period Total Cost	4,833,861	4,717,394	4,648,266	4,621,468
Study Period Total Cost	7,427,249	7,061,938	6,842,410	6,756,836
Planning Rank	4	3	2	1
Study Rank	4	3	2	1

No Burning Desire

In No Burning Desire, rates decrease about 2.1¢/kWh in 2033 when comparing the 110% level against the 35% level. This indicates that there may be a benefit in pursuing an expanded EEPS program, but it will depend upon the current level of sales and future sales trajectory.

Figure 8-29. HELCO No Burning Desire Nominal Price of Electricity for Residential Customers

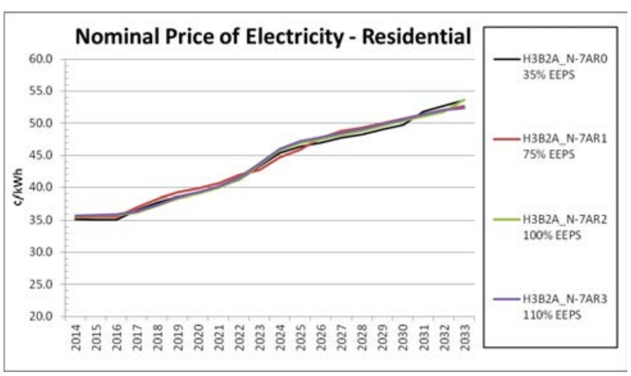
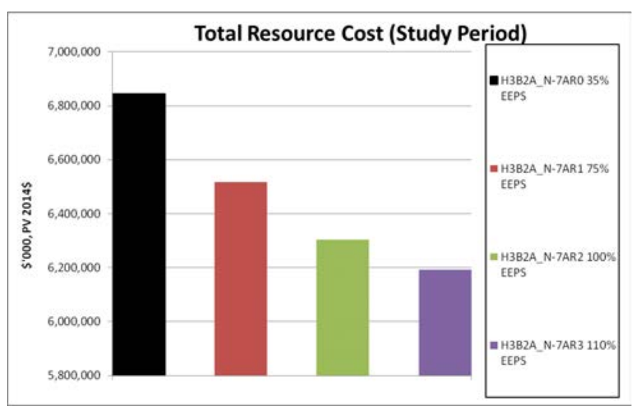


Figure 8-30. HELCO No Burning Desire Total Resource Cost



MECO EEPS Rate Impact Analysis

MECO plans follow a similar trend as Hawaiian Electric and HELCO with increasing levels of EEPS being effective in reducing total resource cost in scenarios with and without load growth.

Blazing a Bold Frontier

Maui risks bearing increased rates by implementing higher levels of EEPS in Blazing a Bold Frontier, but does not seem to gain as much rate savings by doing the same in No Burning Desire. In Blazing a Bold Frontier, rates increase about 36.6¢/kWh in 2033 when comparing the 110% level against the 35% level.

Figure 8-31. MECO Blazing a Bold Frontier Nominal Price of Electricity for Residential Customers

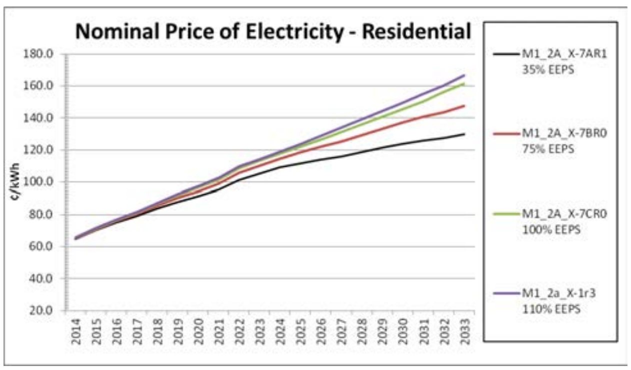
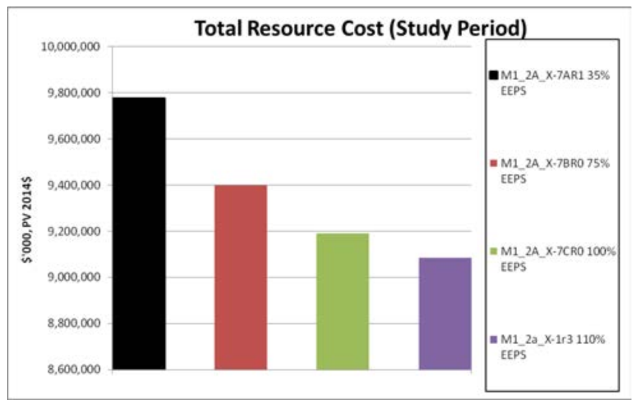


Figure 8-32. MECO Blazing a Bold Frontier Total Resource Cost



Stuck in the Middle

In Stuck in the Middle, rates increase about 4.7¢/kWh in 2033 when comparing the 110% level against the 35% level.

Figure 8-33. MECO Stuck in the Middle Nominal Price of Electricity for Residential Customers

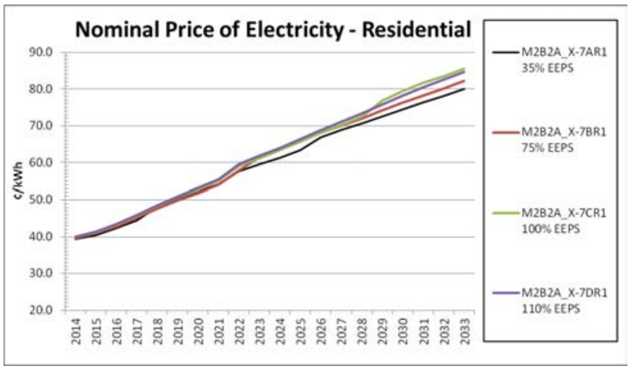


Figure 8-34. MECO Stuck in the Middle Total Resource Cost

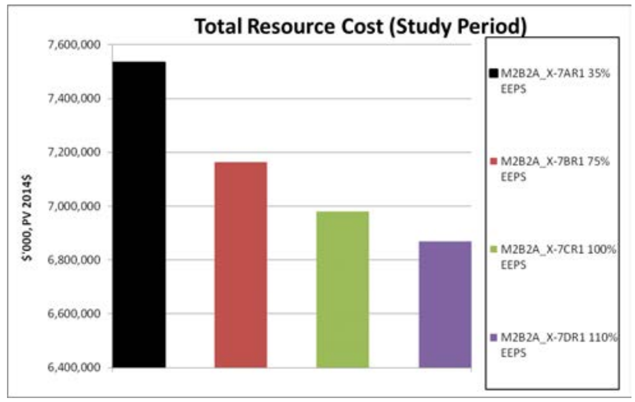


Table 8-20 depicts MECO's EEPS resource plans.

Table 8-20. MECO Stuck in the Middle Resource Plans Showing Capacity Deferral

Name	**M2B2a_X-7Ar1**	**M2B2a_X-7Br1**	**M2B2a_X-7Cr1**	**M2B2a_X-7Dr1**
Plan	SitM EEPS Impact	SitM EEPS Impact	SitM EEPS Impact	SitM EEPS Impact
Notes	35% EEPS Allow ICE 17MW no new as-availables (curtailed okay)	75% EEPS Allow ICE 17MW no new as-availables (curtailed okay)	100% EEPS Allow ICE 17MW no new as-availables (curtailed okay)	110% EEPS Allow ICE 17MW no new as-availables (curtailed okay)
Resources Available	None	None	None	None
DR & DSM Assumptions	35% of Base EEPS Fast DR Only	75% of Base EEPS Fast DR Only	100% of Base EEPS Fast DR Only	110% of Base EEPS Fast DR Only
2014				
2015				
2016				
2017				
2018	ICE biofuel (17 MW)			
2019				
2020				
2021				
2022				
2023		ICE biofuel (17 MW)		
2024				
2025				
2026	ICE biofuel (17 MW)			

Name	M2B2a_X-7ArI	M2B2a_X-7BrI	M2B2a_X-7CrI	M2B2a_X-7DrI
2027				
2028				
2029			ICE biofuel (17 MW)	
2030				
2031				
2032				
2033				
Planning Total Cost	5,152,176.54	4,987,773.51	4,906,928.47	4,861,301.22
Study Total Cost	7,533,073.31	7,163,205.31	6,981,173.31	6,870,003.81
Planning Rank	4	3	2	1
Study Rank	4	3	2	1

No Burning Desire

In No Burning Desire, rates decrease about 1.2¢/kWh in 2033 when comparing the 110% level against the 35% level. This indicates that the risk of increased rates is much greater than the benefit of a possible rate decrease by expanding the EEPS program. Depending upon the trajectory of future sales, a reduced EEPS program may be appropriate for Maui.

Figure 8-35. MECO No Burning Desire Nominal Price of Electricity for Residential Customers

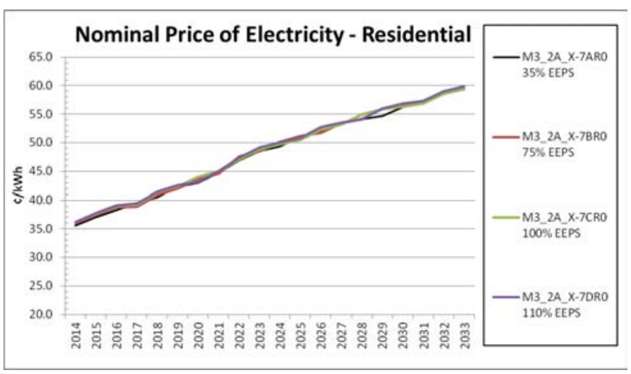
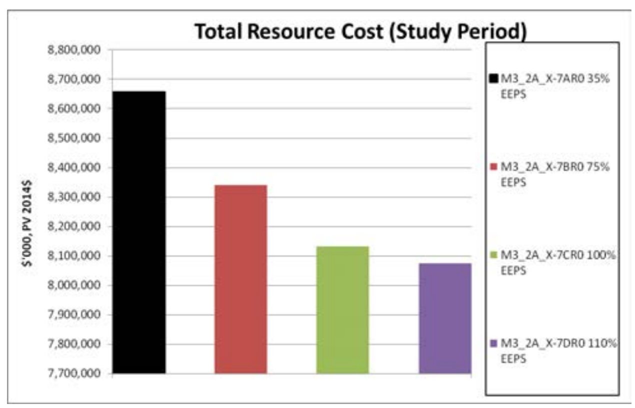


Figure 8-36. MECO No Burning Desire Total Resource Cost



RPS Rate Impact

To analyze the Renewable Portfolio Standard (RPS) rate impact, the Companies evaluated the renewable resource additions under all four scenarios with no RPS required. This enabled the Companies to assess the economics of adding renewable resources to each utility's system and to a consolidated (all-utility) system.

The Companies constructed resource plans to analyze the value of adding both firm and variable renewable resources contrasted against the RPS requirements in the scenarios.

Analyzing Individual Systems

We began by constructing a resource plan with no minimum RPS requirement in all years for all utility systems then compared this plan against a timing run with existing transactions. Existing transactions include known independent power producer contracts with variable generation project developers. The model run then made these transactions unavailable during timing runs to meet the utility reliability criteria and then added back after the firm capacity timing was met. The effect of these transactions on the renewable energy percentage would be fully realized.

This purpose of this comparison was to show if renewable resources could be added to the system to raise the renewable energy percentage while lowering rates. The timing run with transactions is with NEM/FIT growth per the scenario forecast, but no new utility scale renewable resources added outside of firm timing needs; it represents the minimum renewable energy on the system.

The no minimum RPS requirement run is the case where renewables can be added to the system economically and represents the maximum renewable energy that can be added to the system to lower cost. The resulting renewable energy percentage from the no minimum RPS requirement run provides a high-level look at possible renewable energy percentages that can be achieved provided that the renewable resources can be procured at the costs indicated in the UIFs and possible issues with future curtailment can be resolved.

Comparisons of results from the No Minimum RPS and the Firm Timing with Transactions resource plans are shown in Figure 8-37 through Figure 8-59 in each of the four scenarios.

Hawaiian Electric RPS Rate Impact Analysis

Hawaiian Electric Blazing a Bold Frontier Scenario

In Blazing a Bold Frontier, adding renewable energy resources to the Hawaiian Electric system increases the renewable energy percentage. Hawaiian Electric alone can meet the RPS as currently stated on declining sales and no new utility scale renewable generation added, but does not meet the scenario specific RPS 60% by 2030. Variable resource penetration is high due to the added solar, wind, and NEM/FIT resources. This leads to future curtailment issues, even in the firm timing case.

Figure 8-37. HECO Blazing a Bold Frontier Renewable Energy Percentage for Residential Customers

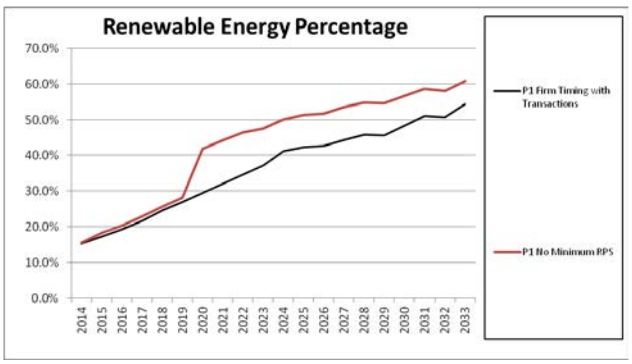


Figure 8-38. HECO Blazing a Bold Frontier Nominal Price of Electricity for Residential Customers

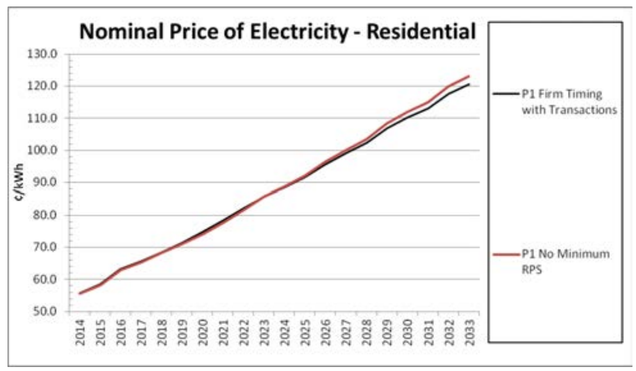


Figure 8-39. HECO Blazing a Bold Frontier Variable Resource Penetration

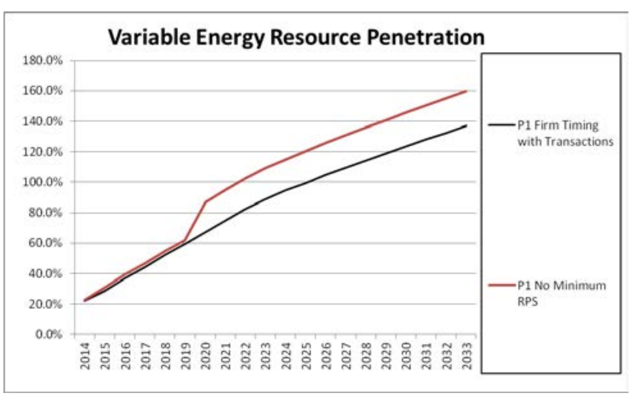


Figure 8-40. HECO Blazing a Bold Frontier Renewable Energy Curtailment

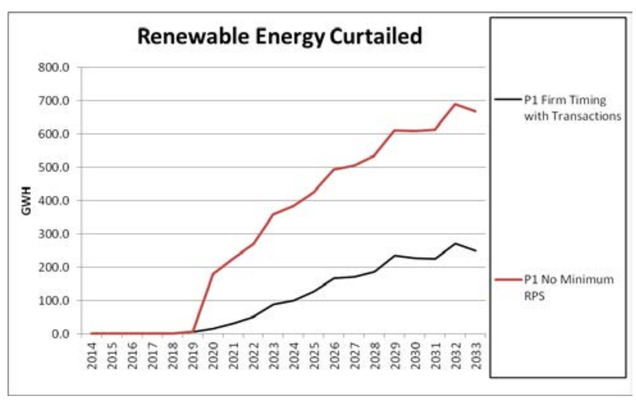


Figure 8-41. HECO Blazing a Bold Frontier Total Resource Cost

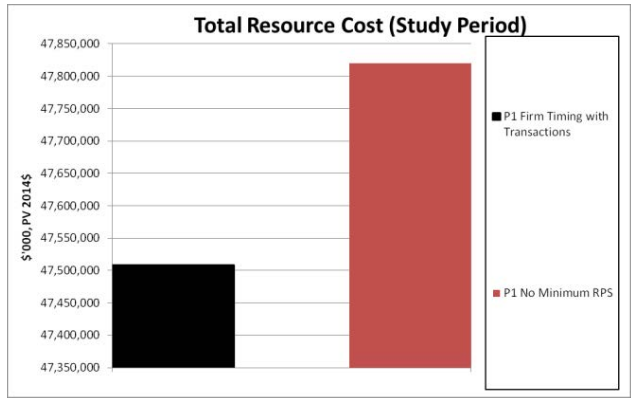


Table 8-21 compares the No Minimum RPS and the Firm Timing with Transactions resource plans under Blazing a Bold Frontier.

Table 8-21. HECO Blazing a Bold Frontier No Minimum RPS Requirement (left) and Firm Timing with Transactions (right) Resource Plan Sheets

Name	**P1B2B1XRETIRE-3AR00%RPS**	**P1_2a1XRetire-7Dr1**
Plan	0% RPS (Wind, PV, Wave, Biomass, CT,ICE)	110% EEPS H89 W34 Ret(ICE,SCCT)
Notes	Lanai Wind in 2020, Wind30, off-shore wind, PV5, & Wave15, CT91 available	With transactions
Resources Available	30MW wind (PW01): 2020 5MW Block of PV (PP03): 2015 15MW Ocean Wave (PV02): 2020 17MW ICE Biofuel (PS01): 2020 91MW SCCT Biofuel (PS07): 2020 25MW Banagrass Combustion (PA01): 2020	
2014	Continue CIDLC, CIDP, RDLCWH, RDLCAC	Continue CIDLC, CIDP, RDLCWH, RDLCAC
	75%+25%+10% PBFA DSM	75%+25%+10% PBFA DSM
2015	Add 20 MW PV (PP03x4)	
2016		
2017	Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW) or Honolulu 8/9	Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW) or Honolulu 8/9
2018		
2019	Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW) or Waiau 3/4	Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW) or Waiau 3/4
2020	Add 200MW Lanai Wind	
2021		
2022		
2023		

Name	P1B2B1XRETIRE-3AR00%RPS	P1_2a1XRetire-7Dr1
2024		
2025		
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
Planning Period Total Cost	35,261,538	35,216,274
Study Period Total Cost	47,820,357	47,508,641

Hawaiian Electric Stuck in the Middle Scenario

In Stuck in the Middle, the combination of adding biofuel conventional generation and biomass combustion for firm timing as well as wind, PV, and NEM/FIT resources greatly increases the renewable energy percentage and decreases rates. Due to growing demand, curtailment is low despite new variable renewable resources and high variable resource penetration. While new variable renewable resources result in greater revenue requirements for capital, there is still a net savings for rates.

Figure 8-42. HECO Stuck in the Middle Renewable Energy Percentage for Residential Customers

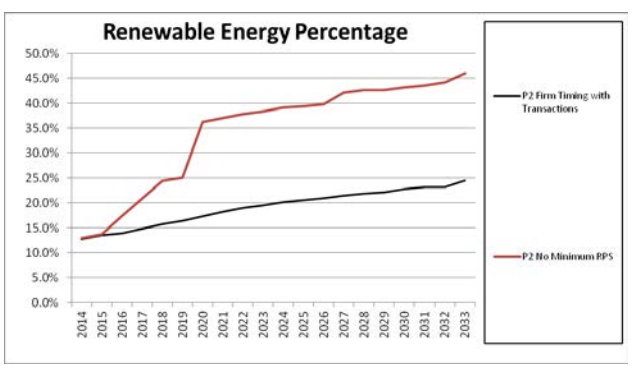


Figure 8-43. HECO Stuck in the Middle Nominal Price of Electricity for Residential Customers

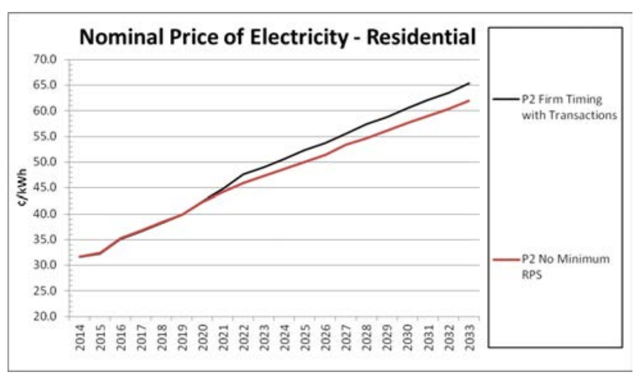


Figure 8-44. HECO Stuck in the Middle Variable Resource Penetration

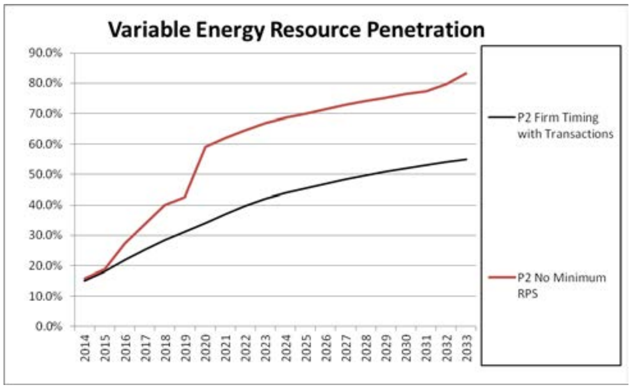


Figure 8-45. HECO Stuck in the Middle Renewable Energy Curtailment

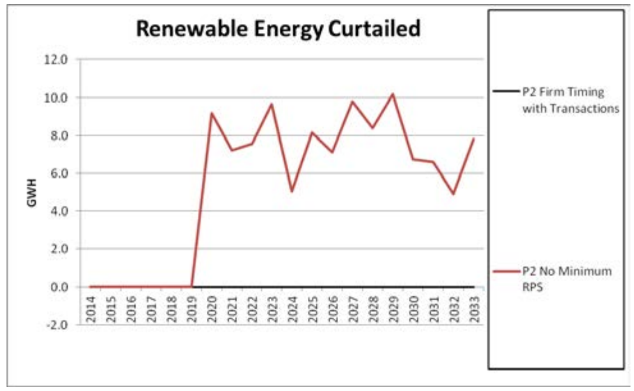


Figure 8-46. HECO Stuck in the Middle Annual Revenue Requirements for Capital

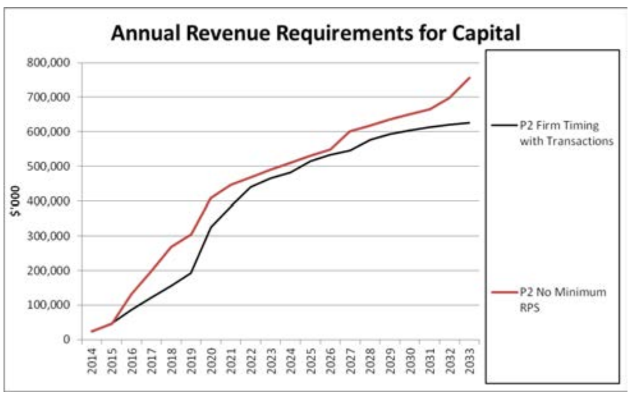


Figure 8-47. HECO Stuck in the Middle Total Resource Cost

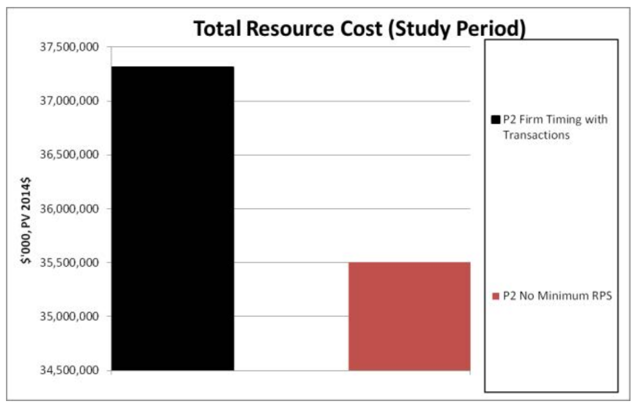


Table 8-22 compares the No Minimum RPS and the Firm Timing with Transactions resource plans under Stuck in the Middle.

Table 8-22. HECO Stuck in the Middle No Minimum RPS Requirement (left) and Firm Timing with Transactions (right) Resource Plan Sheets

Name	**P2B2b1NRetire-3Ar0 0%RPS**	**P2_2a1XRetire-7Br1**
Plan	0% RPS, LanaiW in 2020 (Wind, PV)	75%EEPS,w H89 W34 Ret (ICE)
Notes		With transactions
Resources Available	30MW wind (PW01): 2016 5MW Block PV (PP03): 2015	17MW ICE (PS01): 2016
2014	Expanded CIDLC, CIDP, RDLCWH, RDLCAC	Continue CIDLC, CIDP, RDLCWH, RDLCAC
	75% PBFA DSM	75% PBFA DSM
2015		

Name	P2B2b1NRetire-3Ar0 0%RPS	P2_2a1XRetire-7Br1
2016	Add 60 MW wind (PW01x2)	
	Add 20 MW PV (PP03x4)	
2017	Add 60 MW wind (PW01x2)	
	Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW) or Honolulu 8/9	Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW) or Honolulu 8/9
2018	Add 60 MW wind (PW01x2)	
2019	Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW) or Waiau 3/4	Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW) or Waiau 3/4
2020	Add 59MW CC (PC08x1); biofuel	Add 85MW ICE (PS01x5); biofuel
	Add 200 MW Lanai Wind	
2021		Add 17MW ICE (PS01x1); biofuel
2022		Add 34MW ICE (PS01x2); biofuel
2023		
2024		
2025		Add 17MW ICE (PS01x1); biofuel
2026		
2027	Add 25MW (PA01x1); biomass	
2028		Add 17MW ICE (PS01x1); biofuel
2029		
2030		
2031		
2032	Add 20 MW PV (PP03x4)	
2033	Add 30 MW wind (PW01x1)	
	Add 20 MW PV (PP03x4)	
Planning Period Total Cost	24,848,154	25,590,375
Study Period Total Cost	35,505,523	37,311,593

Hawaiian Electric No Burning Desire Scenario

In No Burning Desire, significant additions of variable renewable resources drive the renewable energy percentage higher and lower rates. Due to the aggressive growth in demand, the RPS as currently mandated cannot be met. The scenario specific RPS, however, can be exceeded by 30% by 2030.

Figure 8-48. HECO No Burning Desire Renewable Energy Percentage and Nominal Price of Electricity for Residential Customers

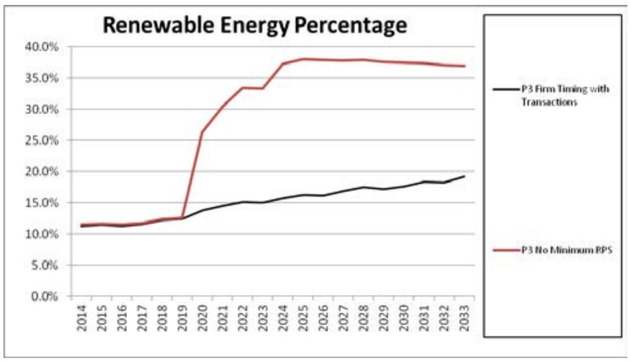


Figure 8-49. HECO No Burning Desire Renewable Energy Percentage and Nominal Price of Electricity for Residential Customers

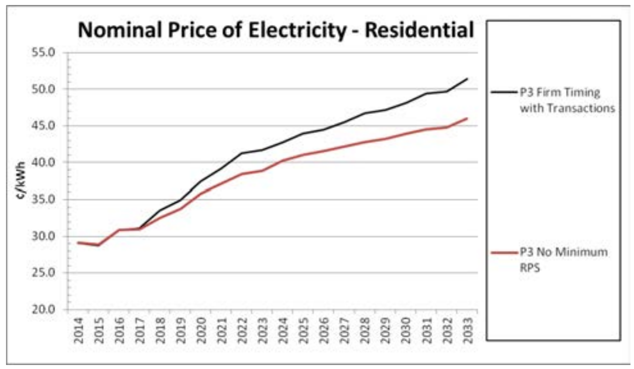


Figure 8-50. HECO No Burning Desire Variable Resource Penetration

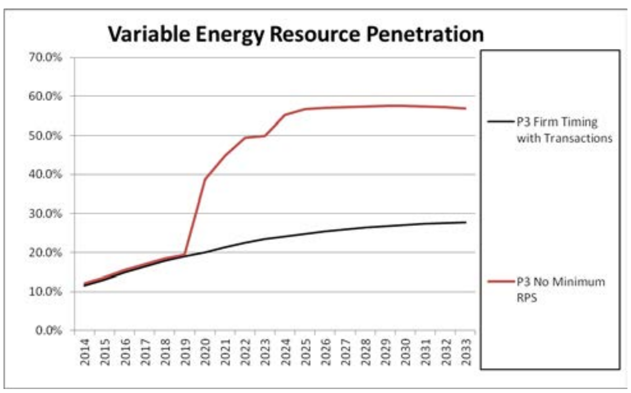


Figure 8-51. HECO No Burning Desire Renewable Energy Curtailment

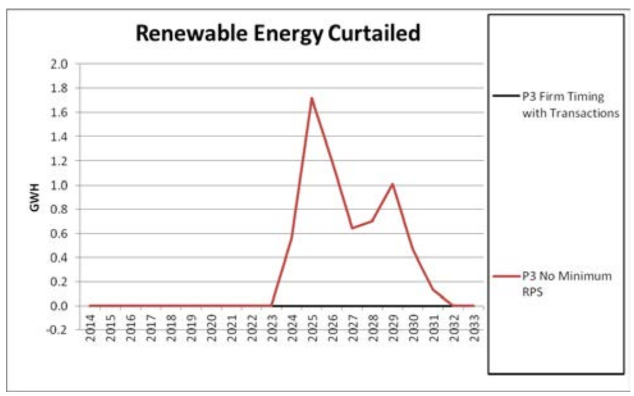


Figure 8-52. HECO No Burning Desire Annual Revenue Requirements for Capital

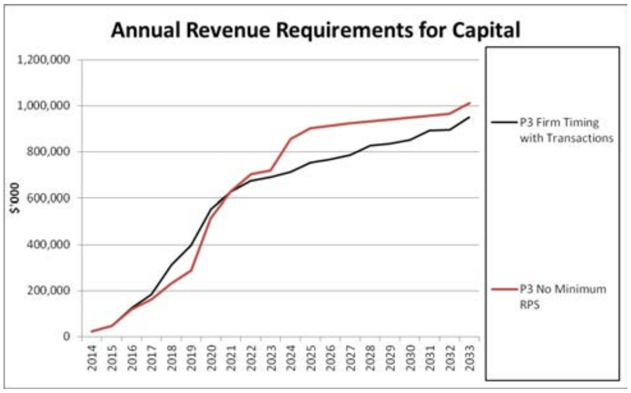


Figure 8-53. HECO No Burning Desire Annual Total Resource Cost

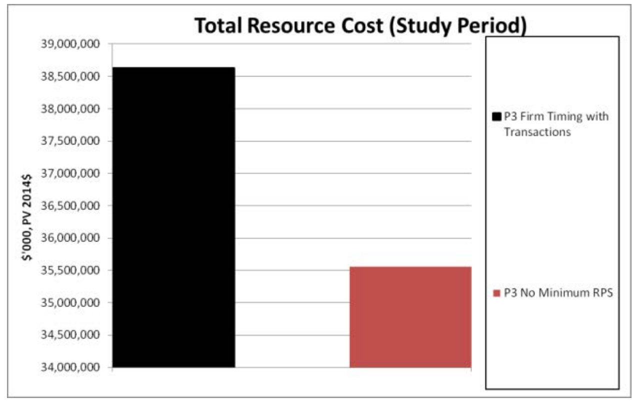


Table 8-23 compares the No Minimum RPS and the Firm Timing with Transactions resource plans under No Burning Desire.

Table 8-23. HECO No Burning Desire No Minimum RPS Requirement (left) and Firm Timing with Transactions (right) Resource Plans

Name	**P3B2b1NRetire-3Ar0 0%RPS**	**P3_2a1XRetire-7Br1**
Plan	0% RPS, LanaiW in 2020 (Wind, PV, Wave, CT, biomass)	EEPS Timing- (ICE)
Notes		With Transactions
Resources Available	30MW wind (PW01): 2018 5MW Block PV (PP03): 2015 15MW Ocean Wave (PV02): 2020 25MW Banagrass Combustion (PA01): 2020	
2014	Expanded CIDLC, CIDP, RDLCWH, RDLCAC	Continue CIDLC, CIDP, RDLCWH, RDLCAC
	75% PBFA DSM	75% PBFA DSM
2015		
2016	Add 91MW SCCT (PS07x1); biofuel	Add 51MW ICE (PS01x3); biofuel
2017		Add 17MW ICE (PS01x1); biofuel
	Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW) or Honolulu 8/9	Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW) or Honolulu 8/9
2018	Add 91MW SCCT (PS07x1); biofuel	Add 119MW ICE (PS01x7); biofuel
2019	Add 17MW ICE (PS01x1); biofuel	Add 34MW ICE (PS01x2); biofuel
	Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW) or Waiau 3/4	Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW) or Waiau 3/4

Name	P3B2b1NRetire-3Ar0 0%RPS	P3_2a1XRetire-7Br1
2020	Add 200 MW Lanai Wind	Add 119MW ICE (PS01x7); biofuel
	Add 150 MW wind (PW01x5)	
	Add 182MW SCCT (PS07x2); biofuel	
2021	Add 120 MW wind (PW01x4)	Add 34MW ICE (PS01x2); biofuel
2022	Add 90 MW wind (PW01x3)	Add 34MW ICE (PS01x2); biofuel
2023		
2024	Add 91MW SCCT (PS07x1); biofuel	Add 17MW ICE (PS01x1); biofuel
	Add 120 MW wind (PW01x4)	
2025	Add 30 MW wind (PW01x1)	Add 34MW ICE (PS01x2); biofuel
2026		
2027		Add 17MW ICE (PS01x1); biofuel
2028		Add 34MW ICE (PS01x2); biofuel
2029		
2030		Add 17MW ICE (PS01x1); biofuel
2031		Add 34MW ICE (PS01x2); biofuel
2032		
2033	Add 34MW ICE (PS01x2); biofuel	Add 51MW ICE (PS01x3); biofuel
Planning Period Total Cost	25,530,999	27,233,260
Study Period Total Cost	35,557,851	38,630,285

Hawaiian Electric Moved by Passion Scenario

In Moved by Passion, adding new variable renewable resources can be cost effective to increase the renewable energy percentage. Under this scenario's slightly declining load, curtailment rises with significant variable resource penetration. Despite this rise in curtailment, additional capital expenditures to add renewable resources are still cost effective.

Figure 8-54. HECO Moved by Passion Renewable Energy Percentage for Residential Customers

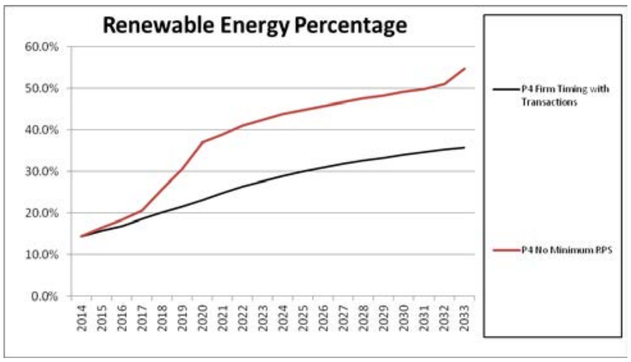


Figure 8-55. HECO Moved by Passion Nominal Price of Electricity for Residential Customers

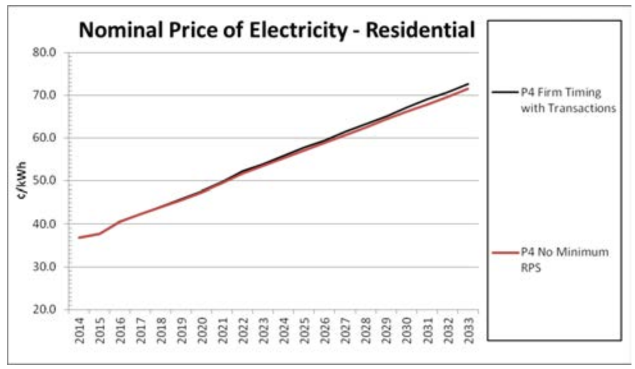


Figure 8-56. HECO Moved by Passion Variable Resource Penetration

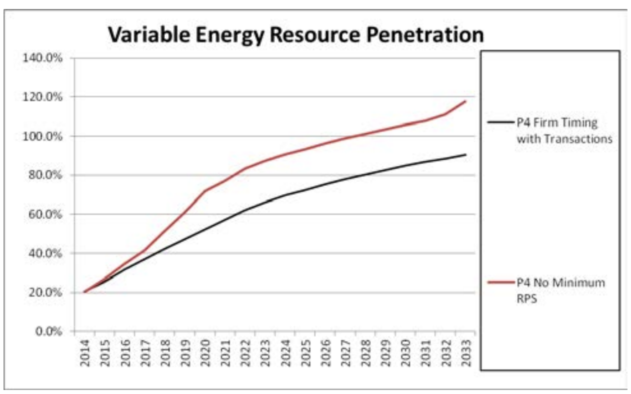


Figure 8-57. HECO Moved by Passion Renewable Energy Curtailment

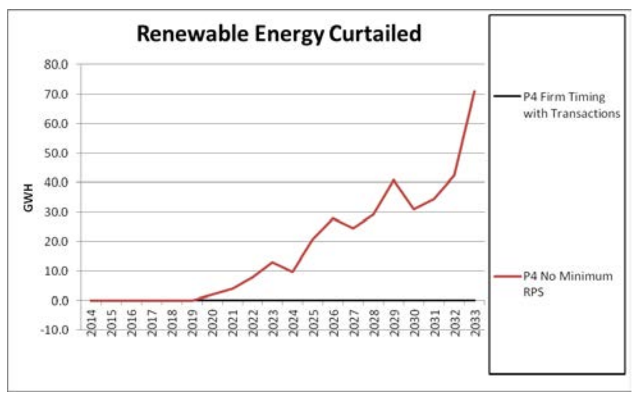


Figure 8-58. HECO Moved by Passion Annual Revenue Requirements for Capital

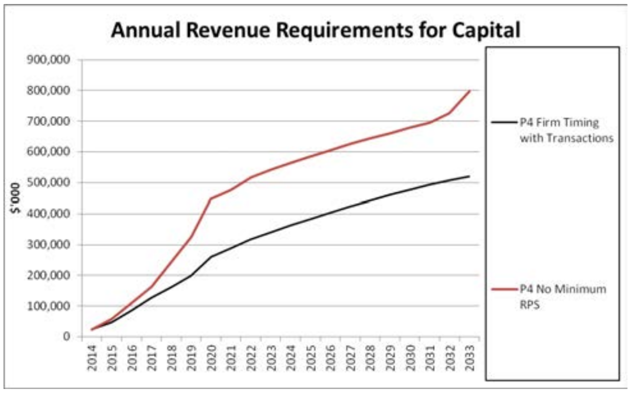


Figure 8-59. HECO Moved by Passion Total Resource Cost

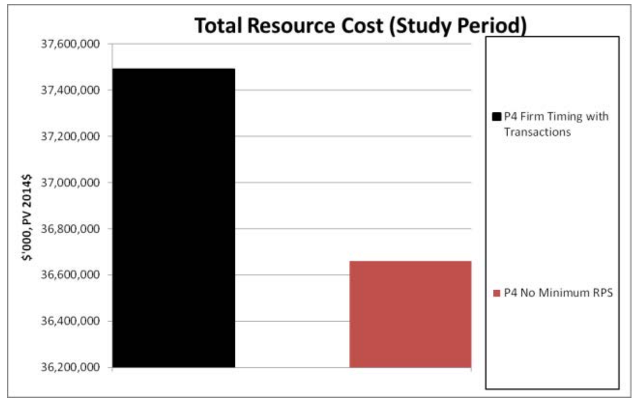


Table 8-24 compares the No Minimum RPS and the Firm Timing with Transactions resource plans under Moved by Passion.

Table 8-24. HECO Moved by Passion No Minimum RPS Requirement (left) and Firm Timing with Transactions (right) Resource Plan Sheets

Name	**P4B2b1NRetire-3Ar0 0%RPS**	**P4_2a1NRetire-1r1 Trans**
Plan	0% RPS, Lanai Wind in 2020 (Wind, PV, Wave, CT, biomass)	Required Timing, Hon8/9, Waiau 4/5 Ret (ICE)
Notes		Firm Timing Run with Transactions
Resources Available	30 MW wind (PW01): 2018 100 MW Offshore Wind (PW05): 2020 5 MW Block PV (PP03): 2015 15 MW Ocean Wave (PV02): 2020 25 MW Banagrass Combustion (PA01): 2020	
2014	Expanded CIDLC, CIDP, RDLCWH, RDLCAC	Expanded CIDLC, CIDP, RDLCWH, RDLCAC
	75%+25% PBFA DSM	75%+25% PBFA DSM
2015	Add 20 MW PV (PP03x4)	
2016	Add 20 MW PV (PP03x4)	Fuel switch to diesel (Honolulu 8/9, Waiau 5–10/Kahe 1-6)
2017	Add 20 MW PV (PP03x4)	
	Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW)	Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW)
2018	Add 20 MW PV (PP03x4)	
	Add 60 MW wind (PW01x2)	
2019	Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW)	Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW)
2020	Add 200 MW Lanai Wind	
2021		
2022		

Name	**P4B2b1NRetire-3Ar0 0%RPS**	**P4_2a1NRetire-1r1 Trans**
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030		
2031	Add 20 MW PV (PP03x4)	
2032	Add 20 MW PV (PP03x4)	
2033	Add 20 MW PV (PP03x4)	
Planning Period Total Cost	26,550,047	26,769,149
Study Period Total Cost	36,659,761	37,489,277

HELCO RPS Rate Impact Analysis

HELCO Blazing a Bold Frontier Scenario

The results from our HELCO analysis are consistent with those for Hawaiian Electric.

In Blazing a Bold Frontier, HELCO currently exceeds the RPS goal and can become 100% renewable while reducing rates. Despite the cycling of Hill 5, Hill 6, and Puna, curtailment could still be possible in later years.

Figure 8-60. HELCO Blazing a Bold Frontier Renewable Energy Percentage for Residential Customers

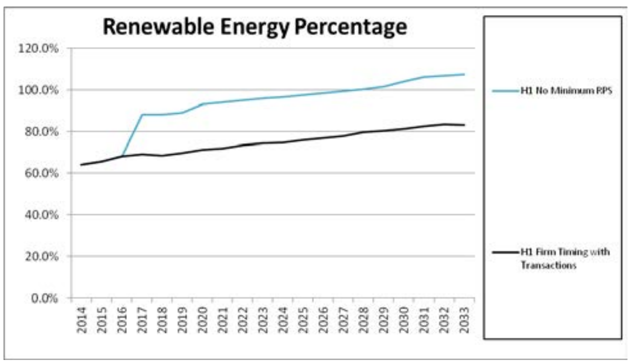


Figure 8-61. HELCO Blazing a Bold Frontier Nominal Price of Electricity for Residential Customers

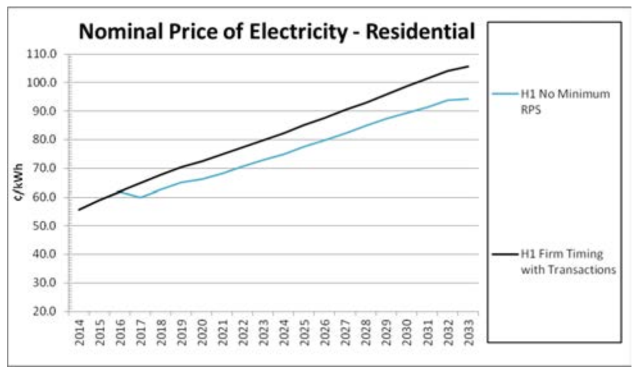


Figure 8-62. HELCO Blazing a Bold Frontier Variable Resource Penetration

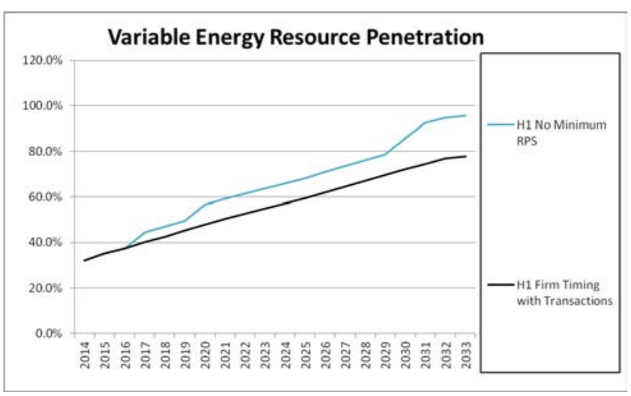


Figure 8-63. HELCO Blazing a Bold Frontier Renewable Energy Curtailment

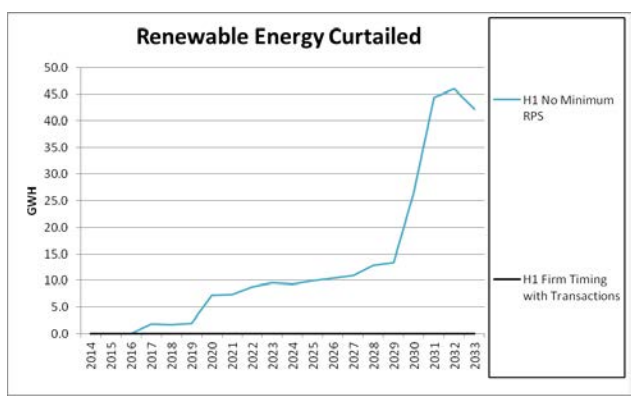


Figure 8-64. HELCO Blazing a Bold Frontier Annual Revenue Requirements for Capital and Total Resource Cost

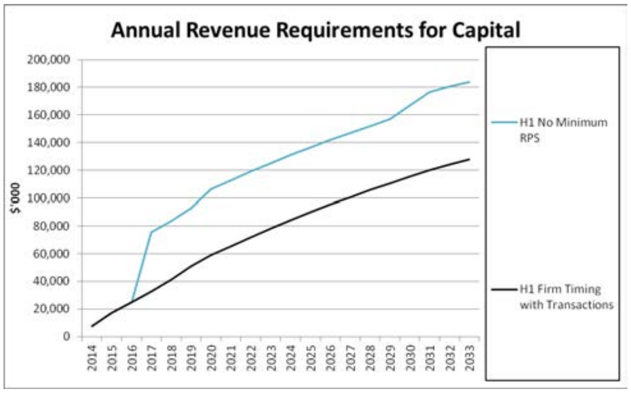


Figure 8-65. HELCO Blazing a Bold Frontier Annual Revenue Requirements for Capital and Total Resource Cost

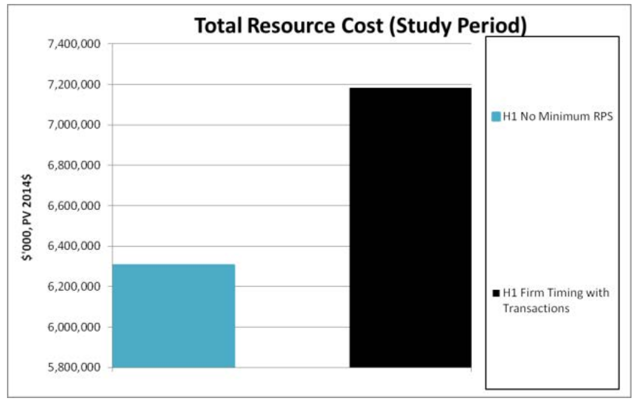


Table 8-25 compares the No Minimum RPS and the Firm Timing with Transactions resource plans under Blazing a Bold Frontier.

Table 8-25. HELCO Blazing a Bold Frontier No Minimum RPS Requirement (left) and Firm Timing with Transactions (right) Resource Plan Sheets

Name	**H1B2A_X-2Ar1-noRPS**	**H1B2A_X-7Ar3**
Plan	HH in, No DR, (Geo, wind, pv, wave, thermal), No RPS	110% EEPS Timing
Notes	Renewable Resources added to lower cost, not meet RPS requirement	
Resources Available	10MW wind (HW04): 2017 1MW PV (HP03): 2015 50MW PV (HP04): 2020 15MW Ocean Wave (HV02): 2020 25MW Advanced Geothermal (HG01): 2017 25MW New Geothermal (HG02): 2020 25MW Banagrass Combustion (HA01): 2017	None
2014	Cycle H5/6, Puna	
	75%+25%+10% PBFA DSM	75%+25%+10% PBFA DSM
	Hu Honua (21.5MW)	Hu Honua (21.5MW)
2015	Deactivate Shipman 3 (–6.8 MW)	Deactivate Shipman 3 (–6.8 MW)
	Deactivate Shipman 4 (–6.7 MW)	Deactivate Shipman 4 (–6.7 MW)
	Add 5MW PV (HP03x5)	
2016		
2017	Add 25MW geothermal (HG01x1)	
	Add 10MW wind (HW04x1)	
2018		
2019		

Name	H1B2A_X-2Ar1-noRPS	H1B2A_X-7Ar3
2020	Add 5MW PV (HP03x5)	
	Add 10MW wind (HW04x1)	
2021	Add 5MW PV (HP03x5)	
2022	Fuel switch to LSIFO (Hill 5/6, Puna Steam)	
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030	Add 10MW wind (HW04x1)	
2031	Add 10MW wind (HW04x1)	
2032		
2033		
Planning Period Total Cost	4,827,514	5,284,953
Study Period Total Cost	6,303,754	7,182,327

HELCO Stuck in the Middle Scenario

In Stuck in the Middle, adding renewable resources continues to lower rates and raise the RPS to a nearly 100% renewable level. Cycling of Hill 5, Hill 6, and Puna combined with load growth may allow for high levels of variable resource penetration on the HELCO system with minimal curtailment.

Figure 8-66. HELCO Stuck in the Middle Renewable Energy Percentage and Nominal Price of Electricity for Residential Customers

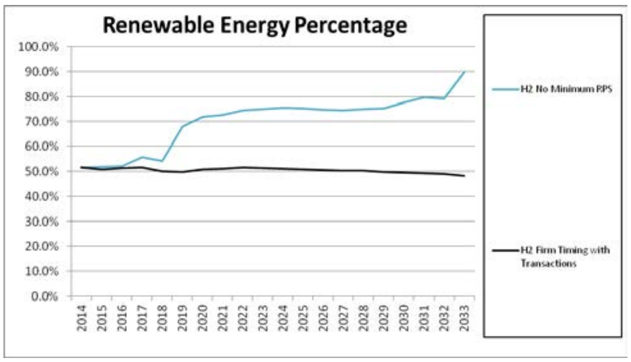


Figure 8-67. HELCO Stuck in the Middle Renewable Energy Percentage and Nominal Price of Electricity for Residential Customers

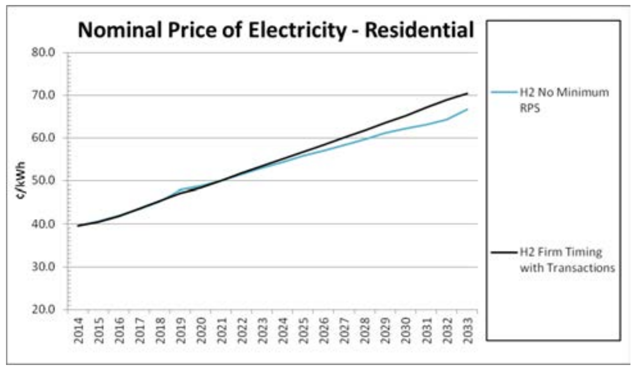


Figure 8-68. HELCO Stuck in the Middle Variable Resource Penetration

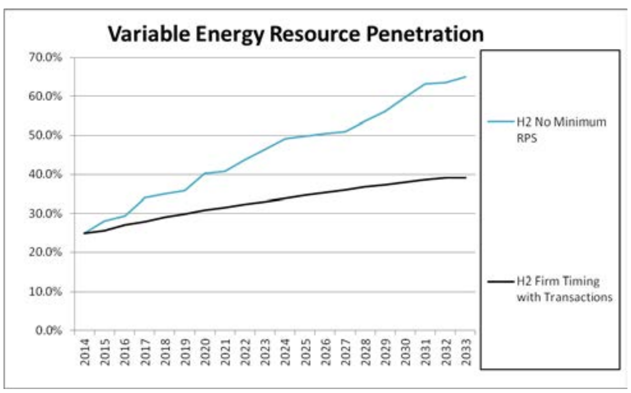


Figure 8-69. HELCO Stuck in the Middle Renewable Energy Curtailment

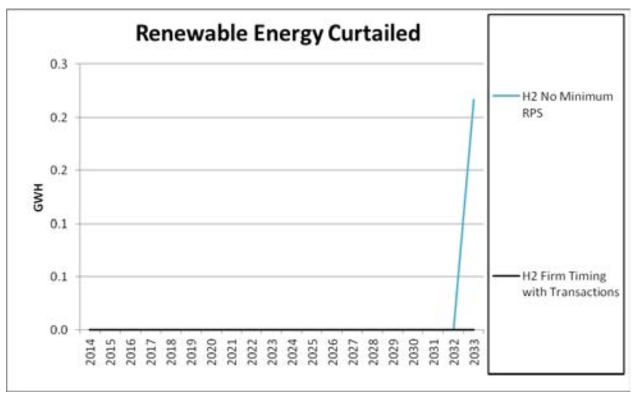


Figure 8-70. HELCO Stuck in the Middle Annual Revenue Requirements for Capital

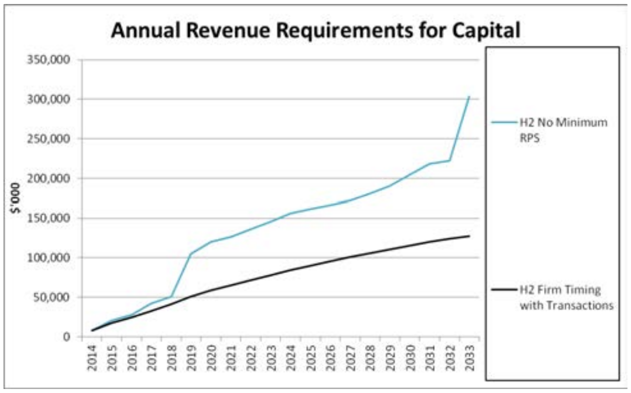


Figure 8-71. HELCO Stuck in the Middle Total Resource Cost

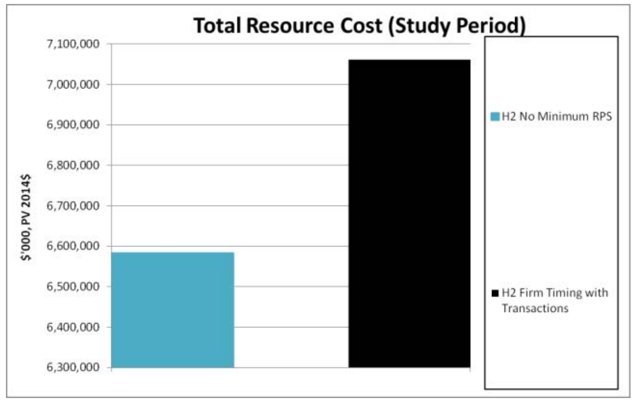


Table 8-26 compares the No Minimum RPS and the Firm Timing with Transactions resource plans under Stuck in the Middle.

Table 8-26. HELCO Stuck in the Middle No Minimum RPS Requirement (left) and Firm Timing with Transactions (right) Resource Plan Sheets

Name	**H2B2A_X-2AR1-NORPS**	**H2B2a_X-7AR1**
Plan	Screen, HHout, NoDR, NoRet, (Geo, Wind, PV, Wave), No RPS	75% EEPS Timing
Notes	Renewable Resources added to lower cost, not meet RPS requirement	Timing Run with 17MW ICE
Resources Available	10MW wind (HW04): 2017 1MW PV (HP03): 2015 50MW PV (HP04): 2020 15MW Ocean Wave (HV02): 2020 25MW Advanced Geothermal (HG01): 2017 25MW New Geothermal (HG02): 2020 25MW Banagrass Combustion (HA01): 2017	None
2014	Cycle Hill 5/6, Puna	
	75% PBFA DSM	75% PBFA DSM
	Hu Honua (21.5MW)	Hu Honua (21.5MW)
2015	Deactivate Shipman 3 (–6.8 MW)	Deactivate Shipman 3 (–6.8 MW)
	Deactivate Shipman 4 (–6.7 MW)	Deactivate Shipman 4 (–6.7 MW)
	Add 5MW PV(HP03x5)	
2016		
2017	Add 10MW wind (HW04x1)	
2018		
2019	Add 25MW geothermal (HG01x1)	
2020	Add 10MW wind (HW04x1)	
2021		

Name	H2B2A_X-2AR1-NORPS	H2B2a_X-7AR1
2022	Add 5MW PV(HP03x5)	
	Fuel switch to LSIFO (Hill 5/6, Puna Steam)	
2023	Add 5MW PV(HP03x5)	
2024	Add 5MW PV(HP03x5)	
2025		
2026		
2027		
2028	Add 5MW PV(HP03x5)	
2029	Add 5MW PV(HP03x5)	
2030	Add 10MW wind (HW04x1)	
2031	Add 10MW wind (HW04x1)	
2032		
2033	Add 5MW PV (HP03x5)	
	Add 25MW geothermal (HG02x1)	
Planning Period Total Cost	4,627,644	4,717,394
Study Period Total Cost	6,582,945	7,061,938

HELCO No Burning Desire Scenario

In No Burning Desire, the variable resource penetration level is lower despite a high renewable energy percentage. Renewable energy percentage driven by firm renewable resources (specifically biofuel ICE and geothermal) results in nearly no curtailed energy even though several onshore wind projects are installed in no minimum RPS requirement.

Figure 8-72. HELCO No Burning Desire Renewable Energy Percentage for Residential Customers

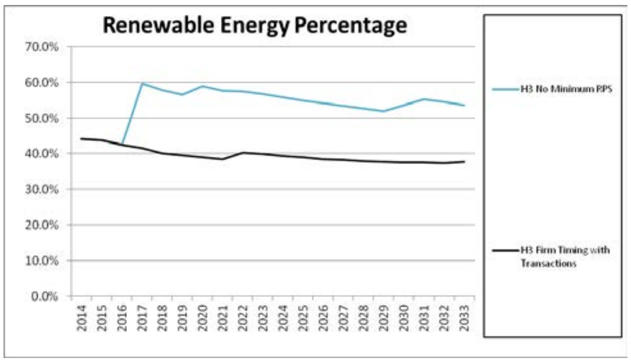


Figure 8-73. HELCO No Burning Desire Nominal Price of Electricity for Residential Customers

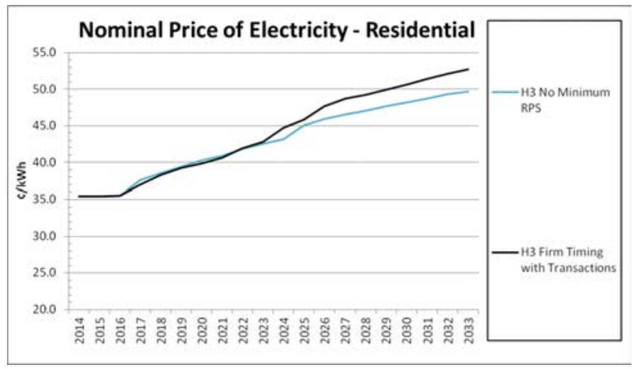


Figure 8-74. HELCO No Burning Desire Variable Resource Penetration

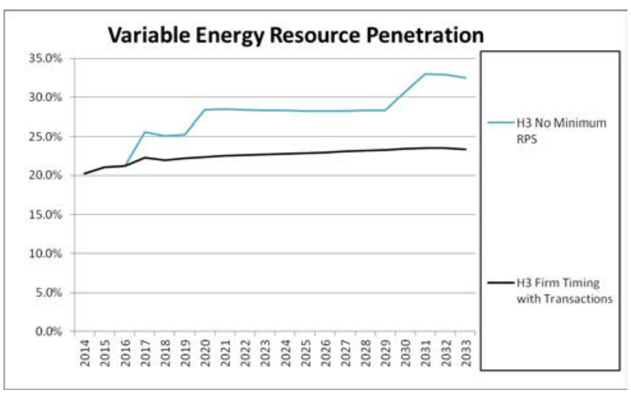


Figure 8-75. HELCO No Burning Desire Renewable Energy Curtailment

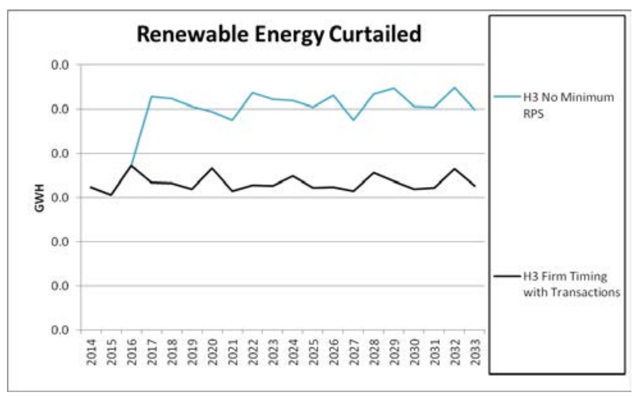


Figure 8-76. HELCO No Burning Desire Annual Revenue Requirements for Capital

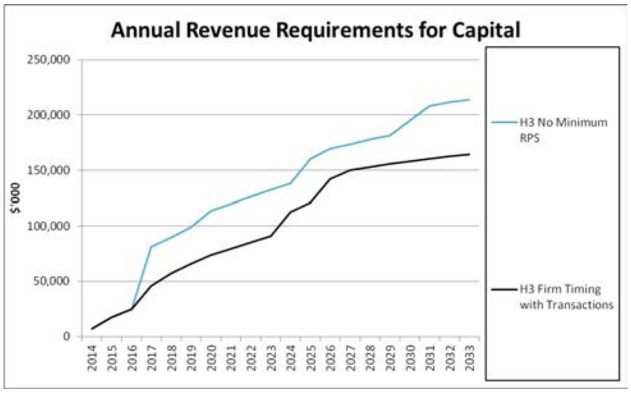


Figure 8-77. HELCO No Burning Desire Total Resource Cost

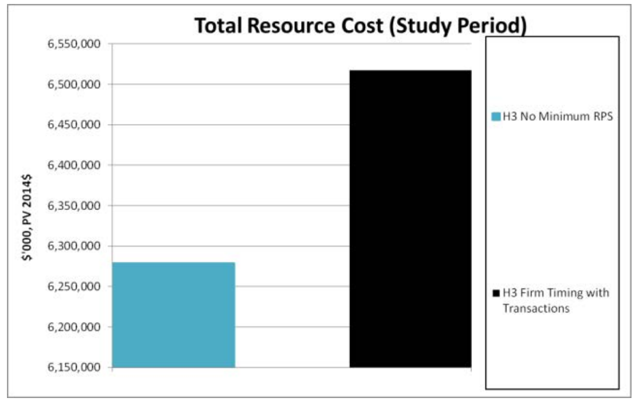


Table 8-27 compares the No Minimum RPS and the Firm Timing with Transactions resource plans under No Burning Desire.

Table 8-27. HELCO No Burning Desire No Minimum RPS Requirement (left) and Firm Timing with Transactions (right) Resource Plan Sheets

Name	H3B2A_N-2r3-noRPS	H3B2a_N-7Ar1
Plan	HH in,w/ DR,Screen,Firm Fixed,(All RE),no RPS	75% EEPS
Notes	Renewable Resources added to lower cost, not meet RPS requirement	Includes Fuel switch to LSIFO (Hill5/6, Puna Steam) in 2022
Resources Available	1 MW PV (HP03): 2015 10MW wind (HW04): 2017 25MW Biom (HT01): 2017 25MW Geo (HG02): 2020 50 MW Trough PV (HP04): 2020 15MW Ocean Wave (HV02): 2020	17MW ICE (HS01): 2016
2014	Cycle H5/6, Puna	
	New CIDLC, Fast DR, RDLCWH, RDLCAC	
	75% PBFA DSM	75% PBFA DSM
	Hu Honua (21.5MW)	Hu Honua (21.5MW)
2015	Deactivate Shipman 3 (–6.8 MW)	Deactivate Shipman 3 (–6.8 MW)
	Deactivate Shipman 4 (–6.7 MW)	Deactivate Shipman 4 (–6.7 MW)
2016		
2017	Add 25 MW geothermal (HG01x1)	Add 17MW ICE (HS01x1); biofuel
	Add 10 MW wind (HW04x1)	
2018		
2019		
2020	Add 10 MW wind (HW04x1)	

Name	H3B2A_N-2r3-noRPS	H3B2a_N-7Ar1
2021		
2022	Fuel switch to LSIFO (Hill 5/6, Puna Steam)	Fuel switch to LSIFO (Hill 5/6, Puna Steam)
2023		
2024		Add 17MW ICE (HS01x1); biofuel
2025	Add 17MW ICE (HS01x1); biofuel	
2026		Add 17MW ICE (HS01x1); biofuel
2027		
2028		
2029		
2030	Add 10 MW wind (HW04x1)	
2031	Add 10 MW wind (HW04x1)	
2032		
2033		
Planning Period Total Cost	4,493,985	4,597,440
Study Period Total Cost	6,278,810	6,517,122

HELCO Moved by Passion Scenario

In Moved by Passion, adding renewable resources enables HELCO to become nearly 100% renewable and reduce rates (similar to Blazing a Bold Frontier). Despite the high level of variable resource penetration, curtailment is not significant. Capital spent to add renewable generation benefits customers by reducing rates.

Figure 8-78. HELCO Moved by Passion Renewable Energy Percentage

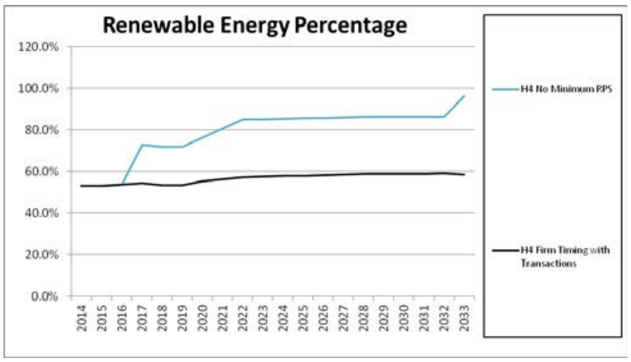


Figure 8-79. HELCO Moved by Passion Nominal Price of Electricity for Residential Customers

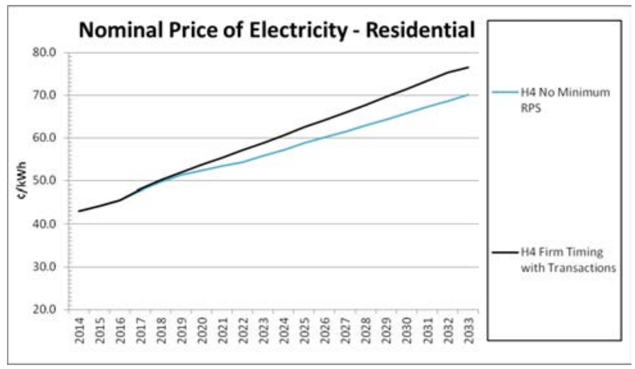


Figure 8-80. HELCO Moved by Passion Variable Resource Penetration

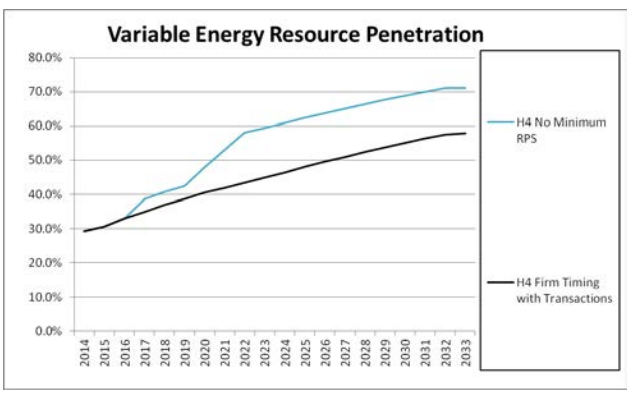


Figure 8-81. HELCO Moved by Passion Renewable Energy Curtailment

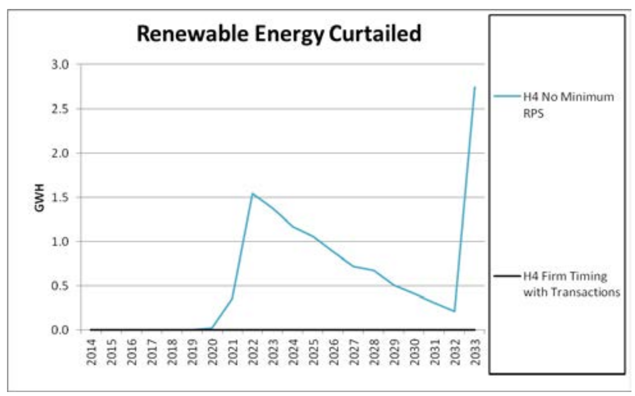


Figure 8-82. HELCO Moved by Passion Annual Revenue Requirements for Capital

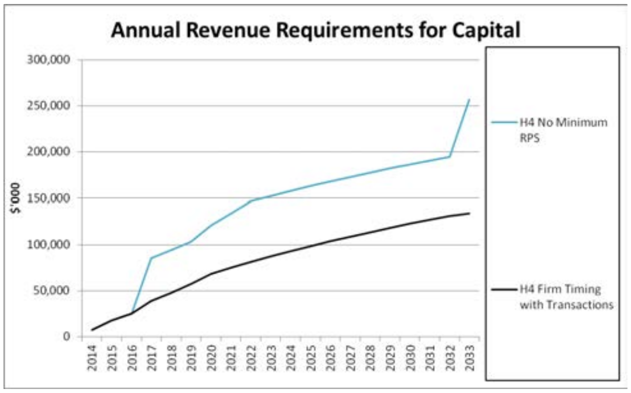


Figure 8-83. HELCO Moved by Passion Total Resource Cost

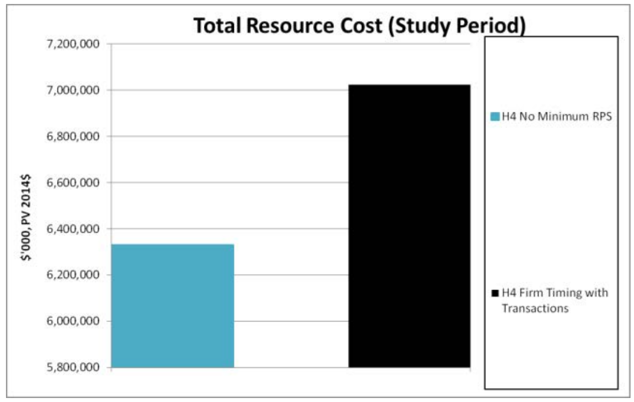


Table 8-28 compares the No Minimum RPS and the Firm Timing with Transactions resource plans under Moved by Passion.

Table 8-28. HELCO Moved by Passion No Minimum RPS Requirement (left) and Firm Timing with Transactions (right) Resource Plan Sheets

Name	**H4B2A_X-2Ar3-noRPS**	**H4_2A_X-1ARr0**
Plan	HH in,Screen,No DR,(Geo,Wind,PV,Wave), no RPS	Firm Timing Run With Transactions
Notes	Renewable Resources added to lower cost, not meet RPS requirement	Timing Run with Firm Conventional Units Available No DR Programs Shipman 3 & 4 Deactivation
Resources available	1 MW PV (HP03): 2015 10 MW wind (HW02), 25MW Geo (HG01), & 25 MW Biom (HT01): 2017 Puna Repower (HRP1): 2018 25MW Geo (HG02): 2020 50 MW Trough PV (HP04): 2020 15MW Ocean Wave (HV02): 2020	17MW ICE (HS01): 2016 21MW CT (HS05): 2017 42MW CT (HS06): 2017
2014	Cycle Hill 5/6, Puna	
	75%+25% PBFA DSM	75%+25%PBFA DSM
	Hu Honua (21.5MW)	Hu Honua (21.5MW)
2015	Deactivate Shipman 3 (–6.8 MW)	Deactivate Shipman 3 (–6.8 MW)
	Deactivate Shipman 4 (–6.7 MW)	Deactivate Shipman 4 (–6.7 MW)
	Add 5MW PV (HP03x5)	
2016		
2017	Add 25MW geothermal (HG01x1)	
	Add 10MW wind (HW04x1)	
2018		
2019		

Name	H4B2A_X-2Ar3-noRPS	H4_2A_X-1ARr0
2020	Add 5MW PV (HP03x5)	
	Add 10MW wind (HW04x1)	
2021	Add 1MW PV (HP03x5)	
	Add 10MW wind (HW04x1)	
2022	Fuel switch to LSIFO (Hill 5/6, Puna Steam)	
	Add 10MW wind (HW04x1)	
2023		
2024	Add 5MW PV (HP03x5)	
2025		
2026		
2027		
2028	Add 5MW PV (HP03x5)	
2029	Add 5MW PV (HP03x5)	
2030		
2031		
2032		
2033	Add 25MW geothermal (HG02x1)	
	Add 5MW PV (HP03x5)	
Planning Period Total Cost	4,671,515	4,920,191
Study Period Total Cost	6,329,003	7,023,111

MECO RPS Rate Impact Analysis

MECO Blazing a Bold Frontier Scenario

In Blazing a Bold Frontier, MECO currently exceeds the current RPS mandate without new utility-scale renewable generation. Due to the existing curtailment, high level of variable resource penetration, and falling demand, adding new variable renewable resources presents challenges.

Resource plans with new renewable generation were not considered because curtailment was high. The firm timing with transactions run already has 50 GWh of curtailed renewable energy and variable resource penetration exceeding 100% in year 2014, with both continuing to escalate in later years.

Figure 8-84. MECO Blazing a Bold Frontier Renewable Energy Percentage for Residential Customers

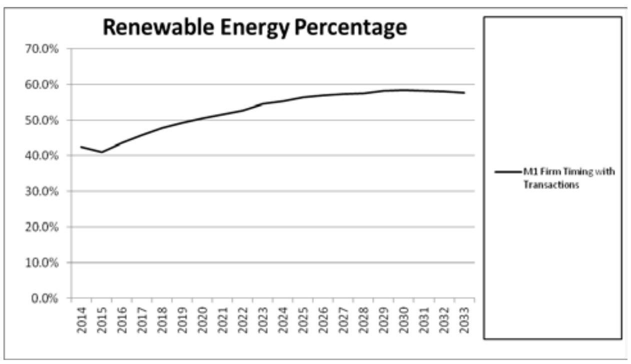


Figure 8-85. MECO Blazing a Bold Frontier Nominal Price of Electricity for Residential Customers

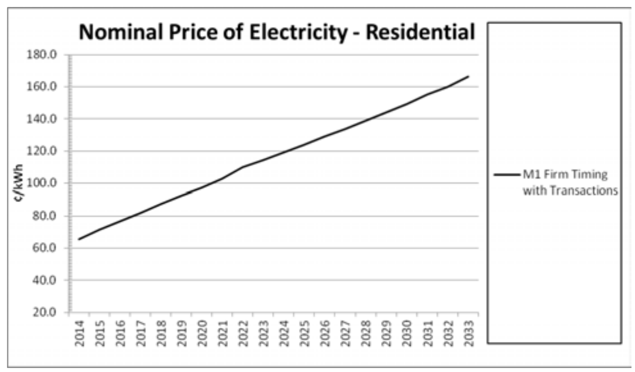


Figure 8-86. MECO Blazing a Bold Frontier Variable Resource Penetration

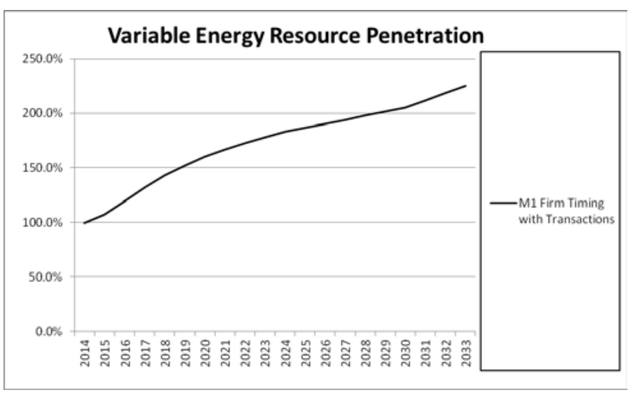


Figure 8-87. MECO Blazing a Bold Frontier Renewable Energy Curtailment

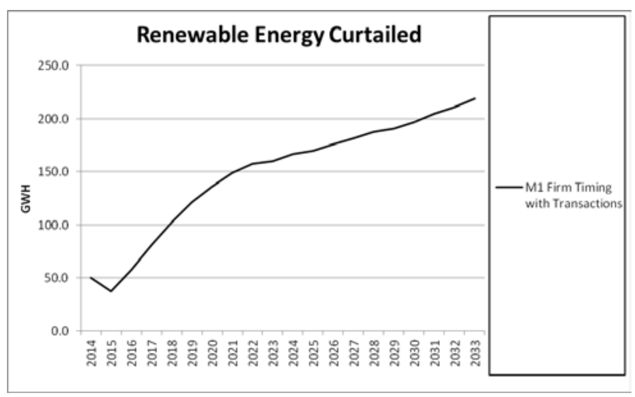


Figure 8-88. MECO Blazing a Bold Frontier Total Resource Cost

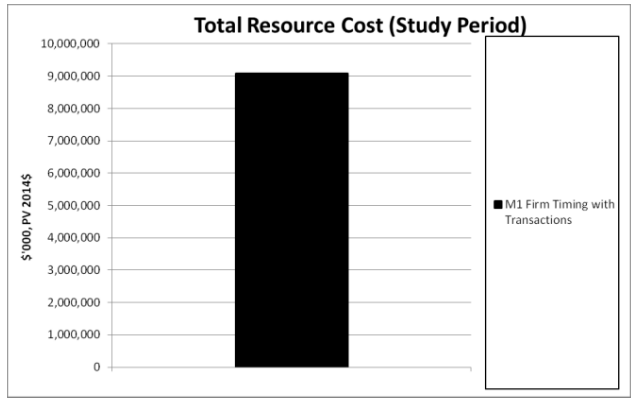


Table 8-29 shows the No Minimum RPS resource plan under Blazing a Bold Frontier.

Table 8-29. MECO Blazing a Bold Frontier Firm Timing with Transactions Resource Plan Sheet

Name	**M1_2a_X-1r3**
Plan	No Minimum RPS Requirement
Notes	Unit Timing Rule 1 17MW ICE, 5MW ICE, LM2500, Geo, WTE, Biomass HC&S contract terminated 2014
Resources Available	17MW ICE Biofuel (MS01): 2022 5MW ICE Biofuel (MS14): 2022 25MW Geothermal (MG02): 2022 25MW Banagrass Combustion (MA01): 2022 8MW WTE (MT01): 2022 21MW SCCT Biofuel (MS05): 2022
DR & DSM Assumptions	110% of Base EEPS Fast DR Only
2014	
2015	
2016	
2017	
2018	
2019	
2020	
2021	
2022	
2023	
2024	

Name	M1_2a_X-1r3
2025	
2026	
2027	
2028	
2029	
2030	
2031	
2032	
2033	
Planning Total Cost	6,764,417.73
Study Total Cost	9,085,213.81

MECO Stuck in the Middle Scenario

In Stuck in the Middle, installing new renewable resources to raise the renewable energy percentage has the potential to lower rates. Unlike the Hawaiian Electric and HELCO systems, renewable curtailments are greater and could escalate quickly when adding variable renewable resources. With no new variable resources added, the variable resource penetration reaches 100% even with load growth.

Figure 8-89. MECO Stuck in the Middle Renewable Energy Percentage

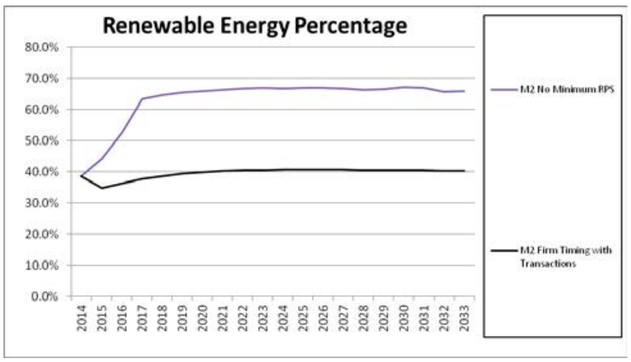


Figure 8-90. MECO Stuck in the Middle Nominal Price of Electricity for Residential Customers

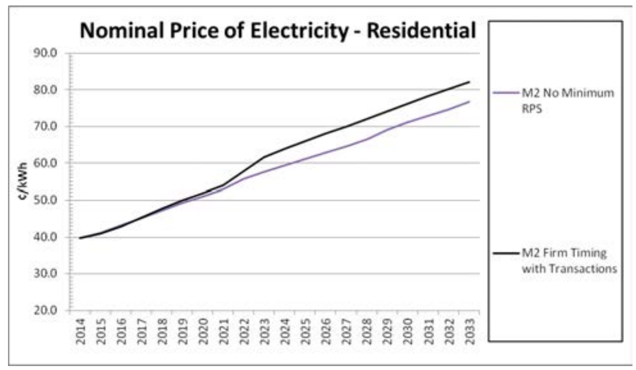


Figure 8-91. MECO Stuck in the Middle Variable Resource Penetration

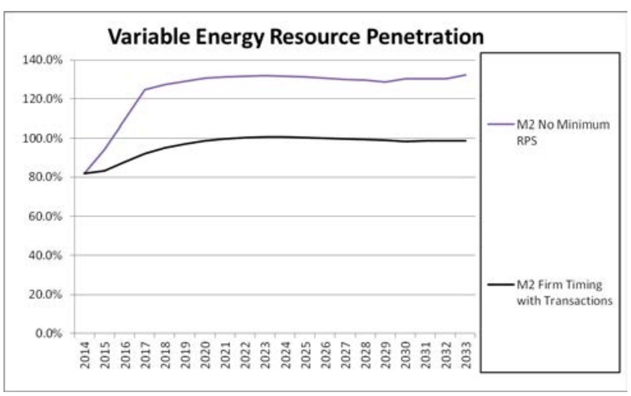


Figure 8-92. MECO Stuck in the Middle Renewable Energy Curtailment

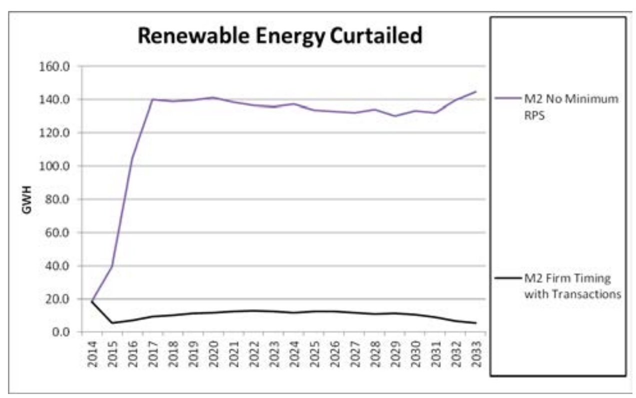


Figure 8-93. MECO Stuck in the Middle Annual Revenue Requirements for Capital

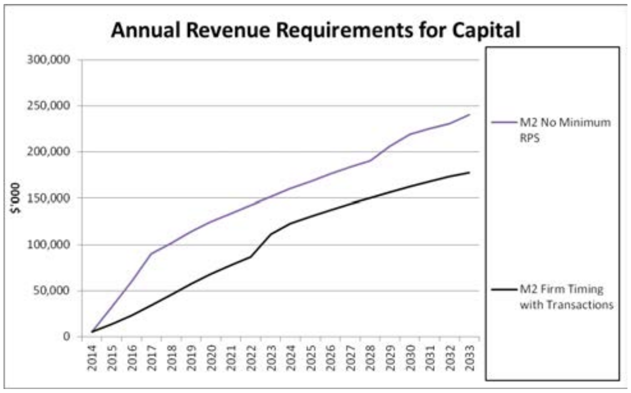


Figure 8-94. MECO Stuck in the Middle Total Resource Cost

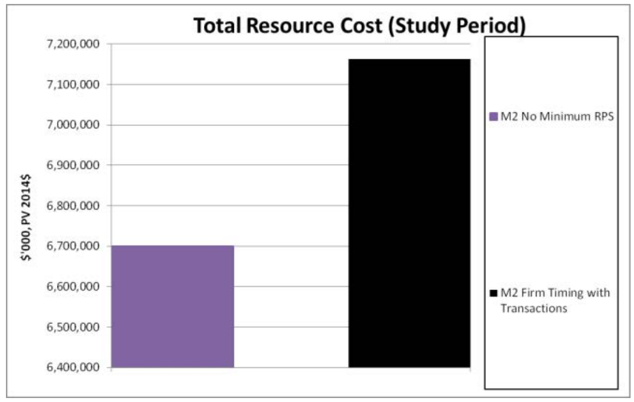


Table 8-30 compares the No Minimum RPS and the Firm Timing with Transactions resource plans under Stuck in the Middle.

Table 8-30. MECO Stuck in the Middle No Minimum RPS Requirement (left) and Firm Timing with Transactions (right) Resource Plan Sheets

Name	**M2_2__N-2r15**	**M2B2a_X-7Br1**
Plan	No Minimum RPS Requirement	SitM EEPS Impact
Notes	New ICE (5 MW): 2029 fixed Allow limited Wind, PV, Wave	75% EEPS Allow ICE 17MW No new as-available (curtailed okay)
Resources Available	10MW wind (MW04): 2015 1MW PV (MP03): 2015 15MW Ocean Wave (MV02): 2015	
DR & DSM Assumptions	75% of Base EEPS All DR: CIDLC Exp, RDLC Exp, Fast DR	75% of Base EEPS Fast DR Only
2014		
2015	3x Wind (10 MW)	
2016	3x Wind (10 MW)	
2017	3x Wind (10 MW)	
2018		
2019		
2020		
2021		
2022		
2023		ICE biofuel (17 MW)
2024		
2025		
2026		

Name	**M2_2__N-2r15**	**M2B2a_X-7Br1**
2027		
2028		
2029	ICE biofuel (5 MW)	
2030	5x PV (1 MW)	
2031		
2032		
2033	5x PV (1 MW)	
Planning Total Cost	4,741,811	4,987,773.51
Study Total Cost	6,699,233	7,163,205.31

MECO No Burning Desire Scenario

In No Burning Desire, variable resource penetration and curtailment falls over time. New renewable generation is a mix of conventional biofuel resources, geothermal, and onshore wind.

Figure 8-95. MECO No Burning Desire Renewable Energy Percentage for Residential Customers

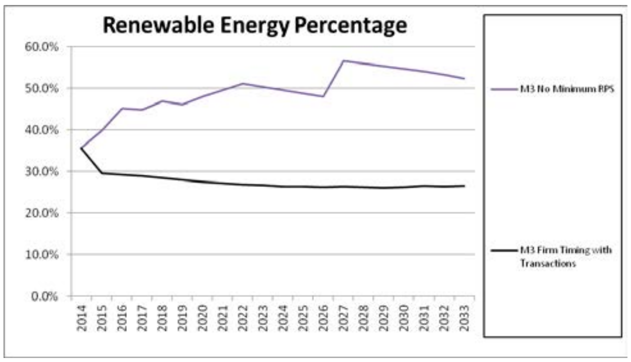


Figure 8-96. MECO No Burning Desire Nominal Price of Electricity for Residential Customers

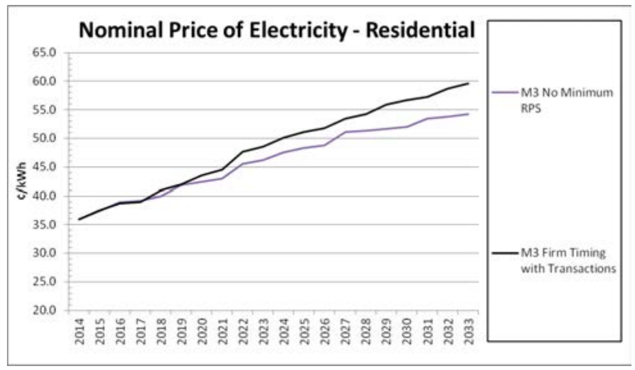


Figure 8-97. MECO No Burning Desire Variable Resource Penetration

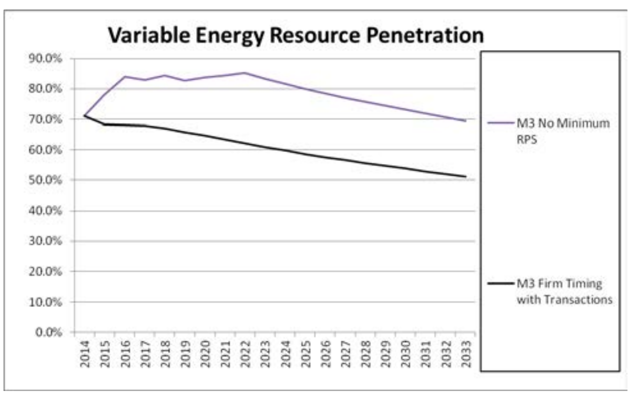


Figure 8-98. MECO No Burning Desire Renewable Energy Curtailment

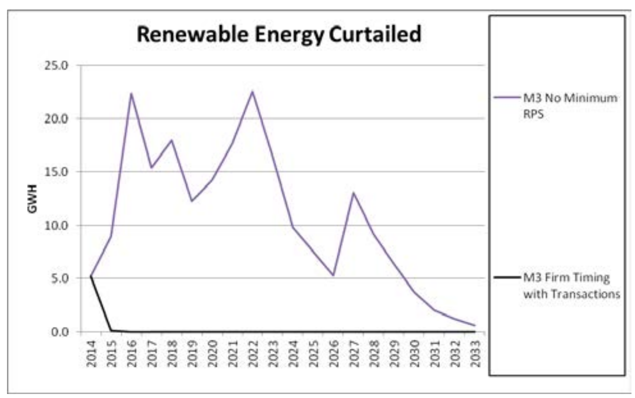


Figure 8-99. MECO No Burning Desire Annual Revenue Requirements for Capital

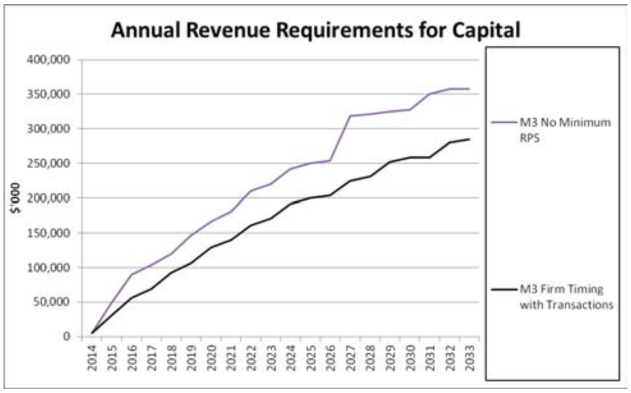


Figure 8-100. MECO No Burning Desire Total Resource Cost

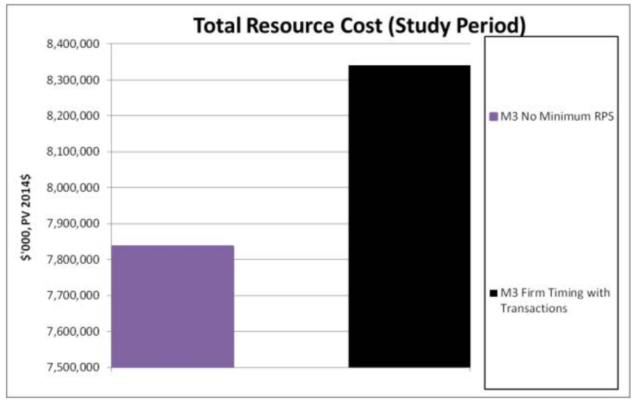


Table 8-31 compares the No Minimum RPS and the Firm Timing with Transactions resource plans under No Burning Desire.

Table 8-31. MECO No Burning Desire No Minimum RPS Requirement (left) and Firm Timing with Transactions (right) Resource Plan Sheets

Name	**M3_2a_N-2r4**	**M3_2a_X-7Br0**
Plan	No Minimum RPS Requirement	NBD Timing 17 MW ICE
Notes	Firm Resource Timing on Rule 1, fixed from Unit Timing Run M3_2a_N-2r3, All DR, HC&S contract expires 12/31/2014	EEPS Impact 17 MW SC Timing on Rule 1 No Existing Unit Retirements
Resources Available	10MW wind (MW04): 2015 1MW PV (MP03): 2015 25MW Banagrass Combustion (MA01): 2023	
DR & DSM Assumptions	75% of Base EEPS All DR: CIDLC Exp, RDLC Exp, Fast DR	75% of Base EEPS Fast DR
2014		
2015	(3) 5 MW ICE; biofuel [MS14]	(3) 5 MW ICE; biofuel [MS14]
	(3) 10 MW wind [MW04]	
2016	(1) 21 MW SC LM2500; biofuel [MS05]	(1) 17 MW ICE; biofuel [MS01]
	(2) 10 MW wind [MW04]	
2017		
2018	(1) 10 MW wind [MW04]	(1) 17 MW ICE; biofuel [MS01]
2019	(1) 21 MW SC LM2500; biofuel [MS05]	
2020	(1) 10 MW wind [MW04]	(1) 17 MW ICE; biofuel [MS01]
2021	(1) 10 MW wind [MW04]	
2022	(1) 17 MW ICE; biofuel [MS01]	(1) 17 MW ICE; biofuel [MS01]
	(1) 10 MW wind [MW04]	
2023		

Name	M3_2a_N-2r4	M3_2a_X-7Br0
2024	(1) 17 MW ICE; biofuel [MS01]	(1) 17 MW ICE; biofuel [MS01]
2025		
2026		
2027	(1) 25 MW new geothermal [MG02]	(1) 17 MW ICE; biofuel [MS01]
2028		
2029		(1) 17 MW ICE; biofuel [MS01]
2030		
2031	(1) 17 MW ICE; biofuel [MS01]	
2032		(1) 17 MW ICE; biofuel [MS01]
2033		
Planning Total Cost	5,561,250	5,840,469
Study Total Cost	7,836,767	8,340,902

MECO Moved by Passion Scenario

In Moved by Passion, adding variable renewable resources results in future curtailment and variable resource penetration (similar to Stuck in the Middle).

Figure 8-101. MECO Moved by Passion Renewable Energy Percentage for Residential Customers

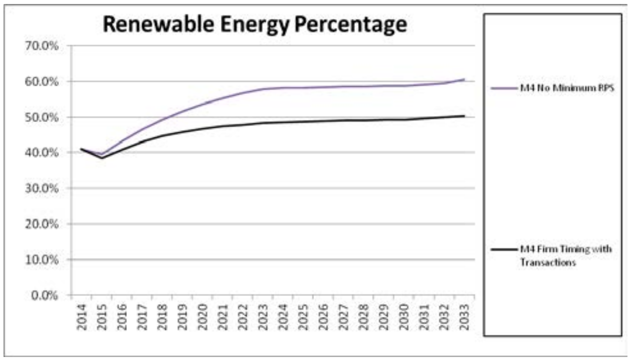


Figure 8-102. MECO Moved by Passion Nominal Price of Electricity for Residential Customers

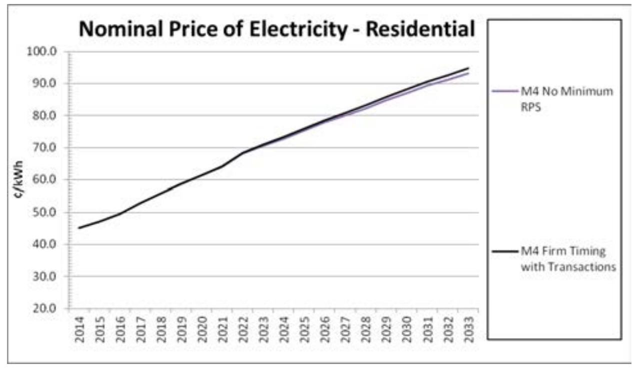


Figure 8-103. MECO Moved by Passion Variable Resource Penetration

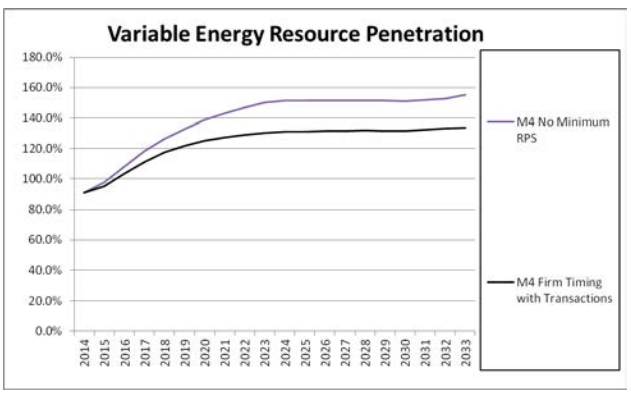


Figure 8-104. MECO Moved by Passion Renewable Energy Curtailment

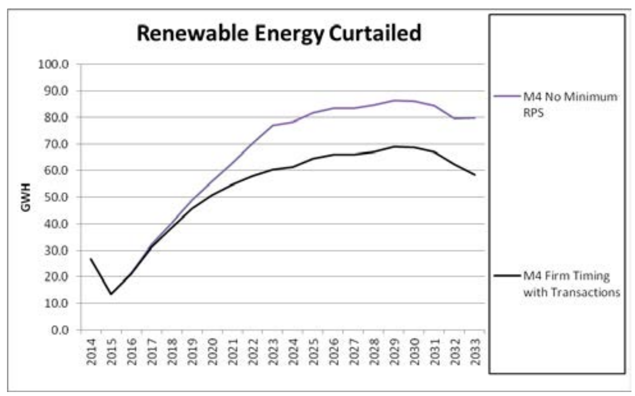


Figure 8-105. MECO Moved by Passion Annual Revenue Requirements for Capital

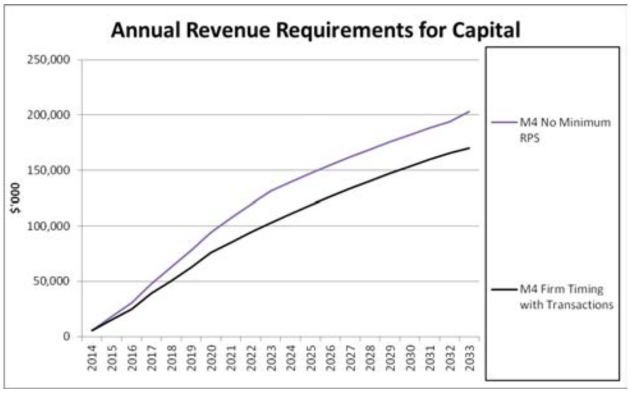


Figure 8-106. MECO Moved by Passion Total Resource Cost

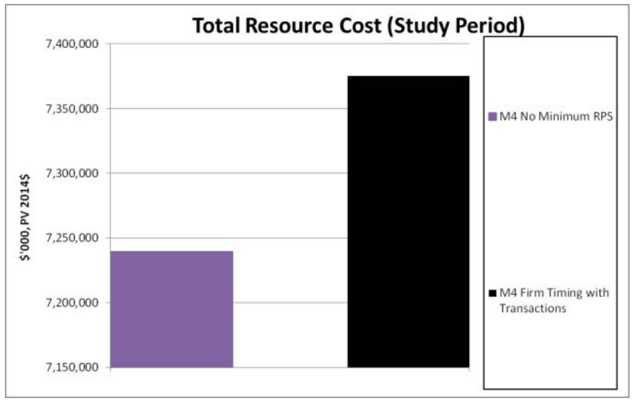


Table 8-32 compares the No Minimum RPS and the Firm Timing with Transactions resource plans under Moved by Passion.

Table 8-32. MECO Moved by Passion No Minimum RPS Requirement (left) and Firm Timing with Transactions (right) Resource Plan Sheets

Name	**M4_2a_X-2r12**	**M4_2A_X-7Cr0**
Plan	No Minimum RPS Requirement	MBP 100% EEPS
Notes		Firm Timing Run with Transactions
Resources Available	10MW wind (MW04): 2015 1MW PV (MP03): 2015 15MW Ocean Wave (MV02): 2015	
DR & DSM Assumptions	100% of Base EEPS Fast DR Only	100% of Base EEPS Fast DR Only
2014		
2015	(5) 1 MW PV [MP03]	
2016	(5) 1 MW PV [MP03]	
2017	(5) 1 MW PV [MP03]	
2018	(5) 1 MW PV [MP03]	
2019	(5) 1 MW PV [MP03]	
2020	(5) 1 MW PV [MP03]	
2021	(5) 1 MW PV [MP03]	
2022	(5) 1 MW PV [MP03]	
2023	(5) 1 MW PV [MP03]	
2024		
2025		
2026		
2027		
2028		

Name	**M4_2a_X-2r12**	**M4_2A_X-7Cr0**
2029		
2030		
2031		
2032		
2033	(5) 1 MW PV [MP03]	
Planning Total Cost	5,280,665.12	5,314,540.88
Study Total Cost	7,239,189.80	7,375,276.30

Assessing the Cost and Rate Impact of RPS

Regardless of the scenario or company, the individual system analyses show that renewable resources can be added to the grid economically. The existing level of RPS or RPS targets do not drive adding renewable resources; instead, the model added these resources to lower total resource cost.

HELCO and MECO easily exceed the current RPS mandate in all scenarios, so no further evaluation was needed.

The Companies used Hawaiian Electric Stuck in the Middle to assess the cost and rate impact of partially attaining, meeting, and exceeding the current RPS mandate (Figure 8-107). The Companies constructed modeling runs to illustrate the cost and rate impact of these various RPS levels (Table 8-33).

Table 8-33. HECO Stuck in the Middle Resource Plans with Increasing Levels of RPS (1 of 2)

Name	**P2_2a1XRetire-7Br1**	**P2B2a1NRetire-2r11**	**P2B2a1NRetire-2r12**
Plan	75%EEPS,w H89 W34 Ret (ICE)	LNG, 30 MW Wind, 5 MW PV, Cycle K1-4, Waiver Projects	LNG, 30 MW Wind, 5 MW PV, Lanai Wind in 2022 Cycle K1-4, Waiver Projects
Notes		CT-1 switch to ULSD in 2016	CT-1 switch to ULSD in 2016
Resources Available	17MW ICE (PS01): 2016	17 MW ICE; Biodiesel (PS01): fixed 25 MW Banagrass Combustion (PA01): fixed 30 MW Onshore Wind Cl 3 (PW01): n/a Lanai Wind: n/a 10 MW Onshore Wind Cl 7 (PW04): n/a 100 MW Offshore Wind (PW05): n/a 5 MW of 1 MW Tracking PV (PP03): n/a 50 MW Parbolic Trough PV (PP04): n/a 9.6 MW OTEC (POT1): n/a 15 MW Ocean Wave (PV02): n/a	17 MW ICE; Biodiesel (PS01): fixed 25 MW Banagrass Combustion (PA01): fixed 30 MW Onshore Wind Cl 3 (PW01): n/a Lanai Wind: n/a 10 MW Onshore Wind Cl 7 (PW04): n/a 100 MW Offshore Wind (PW05): n/a 5 MW of 1 MW Tracking PV (PP03): n/a 50 MW Parbolic Trough PV (PP04): n/a 9.6 MW OTEC (POT1): n/a 15 MW Ocean Wave (PV02): n/a
2014	Continue CIDLC, CIDP, RDLCWH, RDLCAC	Expanded CIDLC, CIDP, RDLCWH, RDLCAC	Expanded CIDLC, CIDP, RDLCWH, RDLCAC
	75% PBFA DSM	75% PBFA DSM	75% PBFA DSM
		Deactivate Honolulu 8 (–53MW) Deactivate Honolulu 9 (–54MW)	Deactivate Honolulu 8 (–53MW) Deactivate Honolulu 9 (–54MW)
2015		Add 20 MW wind (PWWRx2)	Add 20 MW wind (PWWRx2)
		Add 40 MW PV (PPWRx8)	Add 40 MW PV (PPWRx8)
2016		Fuel switch to ULSD (CIP-1)	Fuel switch to ULSD (CIP-1)
			Add 20 MW wind (PWWRx2)
			Add 80 MW PV (PPWRx16)
	Fuel switch to diesel (Honolulu 8–9, Waiau 5–8, Kahe 1–6)	Fuel switch to diesel (Honolulu 8–9, Waiau 5–8, Kahe 1–6)	Fuel switch to diesel (Honolulu 8–9, Waiau 5–8, Kahe 1–6)

Name	P2_2a1XRetire-7Br1	P2B2a1NRetire-2r11	P2B2a1NRetire-2r12
2017		Activate Honolulu 8 (+53MW) Activate Honolulu 9 (+54MW)	Activate Honolulu 8 (+53MW) Activate Honolulu 9 (+54MW)
		Convert CT-1 to CC +57MW (STC1); ULSD	Convert CT-1 to CC +57MW (STC1); ULSD
		Add 51MW ICE (PS01x3); biofuel	Add 51MW ICE (PS01x3); biofuel
		KPLP contract ends (–208 MW)	KPLP contract ends (–208 MW)
	Retire Waiau 3 (–46 MW) Retire Waiau 4 (–46 MW) or Honolulu 8/9	Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW)	Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW)
2018		Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW)	Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW)
		Cycle Kahe 1–4	Cycle Kahe 1–4
		Add 15 MWh battery (PB01x1)	Add 15 MWh battery (PB01x1)
		Add 91 MW SCCT (PS07x1); biofuel	Add 91 MW SCCT (PS07x1); biofuel
2019	Retire Honolulu 8 (–53 MW) Retire Honolulu 9 (–54 MW) or Waiau 3/4		
		Add 91MW SCCT (PS07x1); biofuel	Add 91MW SCCT (PS07x1); biofuel
2020	Add 85MW ICE (PS01x5); biofuel		Add 30 MW wind (PW01x1)
			Add 5 MW PV (PP03x1)
2021	Add 17MW ICE (PS01x1); biofuel		
2022	Add 34MW ICE (PS01x2); biofuel	Add 25MW (PA01x1); biomass	Add 25MW (PA01x1); biomass
			Add 200 MW Lanai Wind
	Fuel switch to ULSD (Honolulu 8–9, Waiau 5–8, Kahe 1–6)	Fuel switch to ULSD (Honolulu 8–9, Waiau 5–8, Kahe 1–6)	Fuel switch to ULSD (Honolulu 8–9, Waiau 5–8, Kahe 1–6)
2023			
2024			
2025	Add 17MW ICE (PS01x1); biofuel		
2026			
2027			
2028	Add 17MW ICE (PS01x1); biofuel		
2029			
2030			
2031			
2032			
2033			
Planning Period Total Cost,	22,898,774	22,840,420	22,026,212
Study Period Total Cost	34,634,216	34,142,728	32,172,264
Planning Period Total Cost	25,590,375	25,517,799	24,703,585

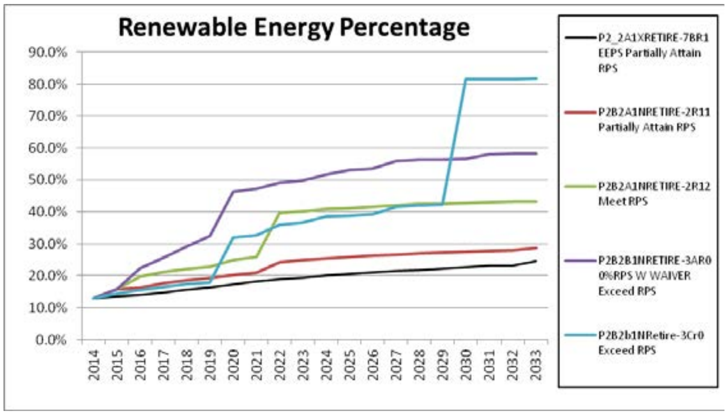
Name	P2_2a1XRetire-7Br1	P2B2a1NRetire-2r11	P2B2a1NRetire-2r12
Study Period Total Cost	37,311,593	36,820,105	34,849,641

Table 8-34. HECO Stuck in the Middle Resource Plans with Increasing Levels of RPS (2 of 2)

Name	P2B2B1NRETIRE-3AR0 0%RPS W WAIVER	P2B2b1NRetire-3Cr0
Plan	No Minimum RPS Requirement, Lanai Wind in 2020, Cycle K1-4, Waiver Projects	100% RE by 2030, Lanai Wind in 2020 (Wind, PV) Convert Existing to Biodiesel in 2030
Notes	Add Renewable Resources Economically	
Resources Available	30 MW Onshore Wind Cl 3 (PW01): 2016 5 MW of 1 MW Tracking PV (PP03): 2015	30 MW Onshore Wind Cl 3 (PW01): 2020 5 MW of 1 MW Tracking PV (PP03): 2015
2014	Expanded CIDLC, CIDP, RDLCWH, RDLCAC	Expanded CIDLC, CIDP, RDLCWH, RDLCAC
	75% PBFA DSM	75% PBFA DSM
2015	Add 20 MW wind (PWWRx2)	Add 20 MW PV (PP03x4)
	Add 40 MW PV (PPWRx8)	
2016	Add 20 MW wind (PWWRx2)	Add 20 MW PV (PP03x4)
	Add 80 MW PV (PPWRx16)	
	Add 60 MW wind (PW01x2)	
	Fuel switch to diesel (Honolulu 8–9, Waiau 5–8, Kahe 1–6)	Fuel switch to diesel (Honolulu 8–9, Waiau 5–8, Kahe 1–6)
2017	Add 60 MW wind (PW01x2)	
	Retire Waiau 3 (–46 MW) Retire Waiau 4 (–46 MW) or Honolulu 8/9	Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW) or Honolulu 8/9
2018	Cycle Kahe 1–4	
	Add 60 MW wind (PW01x2)	
2019	Retire Honolulu 8 (–53 MW) Retire Honolulu 9 (–54 MW) or Waiau 3/4	Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW) or Waiau 3/4
	Add 60 MW wind (PW01x2)	
2020	Add 59MW CC (PC08x1); biofuel	Add 59MW CC (PC08x1); biofuel
	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)
	Add 200 MW Lanai Wind	Add 200 MW Lanai Wind
2021		
2022	Add 30 MW wind (PW01x1)	Add 60 MW wind (PW01x2)
	Fuel switch to ULSD (Honolulu 8–9, Waiau 5–8, Kahe 1–6)	Fuel switch to ULSD (Honolulu 8–9, Waiau 5–8, Kahe 1–6)
2023		
2024	Add 30 MW wind (PW01x1)	Add 30 MW wind (PW01x1)
2025	Add 30 MW wind (PW01x1)	
2026		
2027	Add 25MW (PA01x1); biomass	Add 25MW (PA01x1); biomass

Name	**P2B2B1NRETIRE-3AR0 0%RPS W WAIVER**	**P2B2b1NRetire-3Cr0**
2028		
2029		
2030		Fuel switch to biofuel (Waiau 5–10; Kahe 1–6)
		Add 60 MW wind (PW01x2)
		Add 20 MW PV (PP03x4)
2031	Add 30 MW wind (PW01x1)	
2032		
2033		
Planning Period Total Cost	21,023,188	22,754,010
Study Period Total Cost	30,499,188	32,988,304
Planning Period Total Cost	23,700,565	25,431,385
Study Period Total Cost	33,176,565	35,665,681

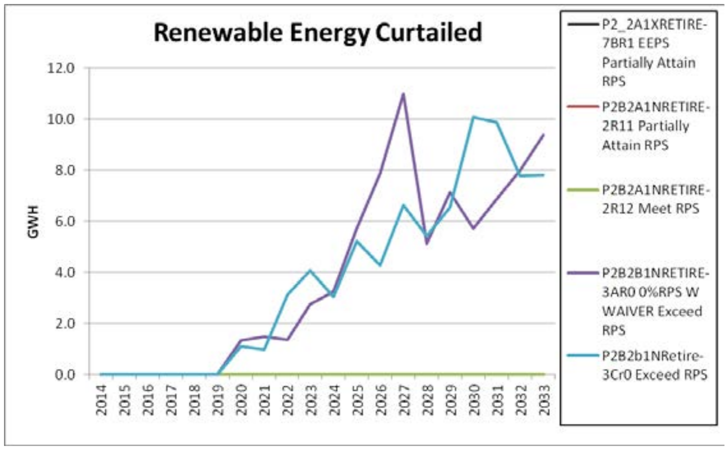
Figure 8-107. HECO Stuck in the Middle Renewable Energy Percentage



The minimum level of RPS is shown by the firm timing run with existing system transactions (P2_2A1XRETIRE-7BR1 EEPS Partially Attain RPS). Two additional runs show partial attainment of the RPS law (P2B2A1NRETIRE-2R11 Partially Attain RPS) and meeting the RPS law (P2B2A1NRETIRE-2R12 Meet RPS).

The modeling run with no minimum RPS requirement (P2B2B1NRETIRE-3AR0 0%RPS W WAIVER Exceed RPS) exceeds the current RPS law while the run with the fuel switch of existing units to biofuel in 2030 demonstrates the highest level of RPS that also exceeds the RPS law.

Figure 8-108. HECO Stuck in the Middle Renewable Energy Curtailment



The Meet RPS resource plan (P2B2A1NRETIRE-2R12 Meet RPS) shows the RPS requirement can be met without curtailment. Higher levels of RPS can be achieved but that risks curtailment in future years.

Figure 8-109. HECO Stuck in the Middle Total Resource Cost

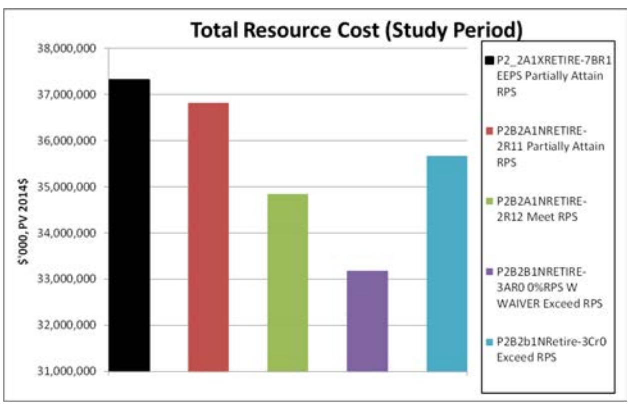
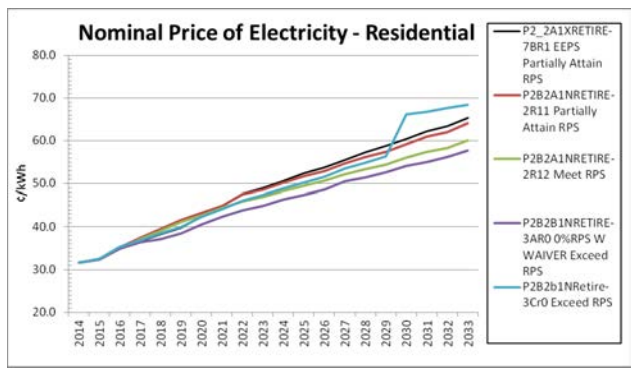


Figure 8-110. HECO Stuck in the Middle Nominal Price of Electricity for Residential Customers



As additional renewable resources are added to the resource plans, the renewable energy percentage increases as the total resource cost while rates decrease. The biofuel switch in 2030 can result in a very high level of RPS, at a cost of increased total resource cost and rates. Switching to biofuels is not needed to exceed the current RPS law. Ultimately, the absolute level of RPS that can be achieved depends on the availability and cost of the renewable resources on each system.

Analysis of Consolidated Systems

The Companies also analyzed a consolidated Hawaiian Electric-HELCO-MECO system. Changes over the analysis of individual systems included:

- Adding fixed firm resources for timing.
- Adding renewable resources across all systems.
- Optionally adding Lanai Wind to all other renewable resources

No minimum RPS requirement was modeled (similar to the individual analyses).

Blazing a Bold Frontier

In Blazing a Bold Frontier, NEM/FIT contributes a significant percentage to RPS with declining load. NEM/FIT additions in 2030 fulfill 30% of the renewable energy percentage. Scenario forecasts show energy provided by NEM/FIT growing six times to 1,800 GWh annually in 2030.

Figure 8-111. Blazing a Bold Frontier Contribution to RPS from NEM/FIT and Renewable Generation Net of NEM/FIT

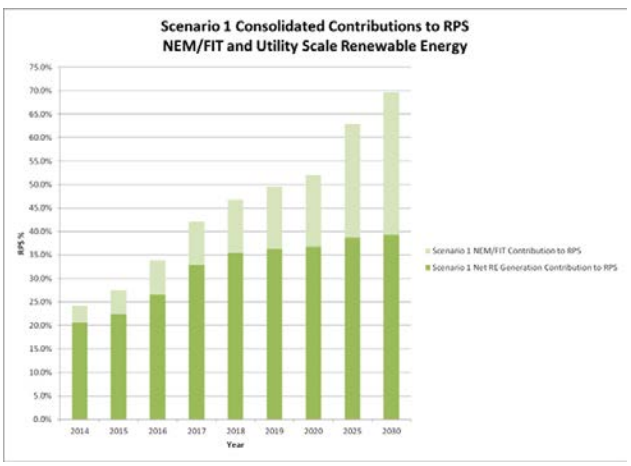


Figure 8-112. Blazing a Bold Frontier Contribution to RPS by Company

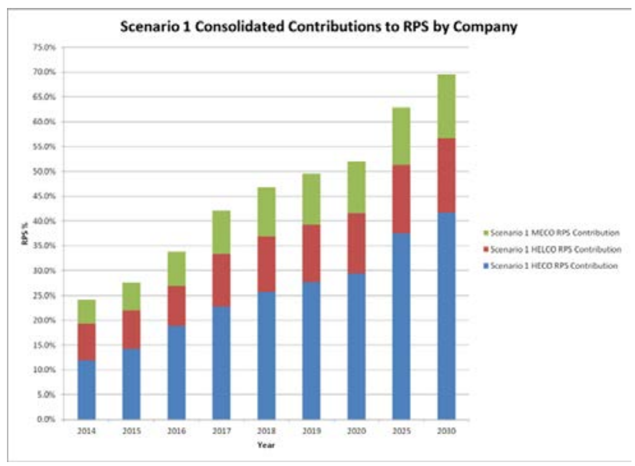


Table 8-35. Blazing a Bold Frontier Breakdown of Sales and NEM/FIT Data (GWh)

	2014	2015	2016	2017	2018	2019	2020	2025	2030
Sales	8,606	8,350	8,142	7,863	7,554	7,331	7,134	6,409	5,941
Total RE Generation	2,078	2,302	2,751	3,309	3,534	3,629	3,711	4,029	4,134
NEM/FIT	300	433	589	722	851	974	1,092	1,550	1,802
Net RE Generation	1,779	1,869	2,162	2,587	2,683	2,655	2,619	2,479	2,332
NEM/FIT Contribution to RPS	3.5%	5.2%	7.2%	9.2%	11.3%	13.3%	15.3%	24.2%	30.3%
Net RE Generation Contribution to RPS	20.7%	22.4%	26.6%	32.9%	35.5%	36.2%	36.7%	38.7%	39.3%

Table 8-36. Blazing a Bold Frontier Consolidated System Resource Plan

Name	**PHM3B2B1NRETIRE-3BR0**		
Plan	HECO Fuel Switch to ULSD in 2020	HELCO Deactivate Existing Replace with Geothermal	MECO Fuel Switch to LSIFO in 2022
Notes	Consolidated No Minimum RPS Run	Consolidated No Minimum RPS Run	Consolidated No Minimum RPS Run
Resources Available	30 MW Wind (PW01): 2017 5 MW PV (PP03): 2015	10 MW Wind (HW01): 2015 1 MW PV (HP03): 2015 25 MW Geothermal (HG01): 2017 25 MW New Site Geothermal (HG02): 2020	10 MW Wind (MW04): 2015 1 MW PV (MP03): 2015
2014	Continue CIDLC, CIDP, RDLCWH, RDLCAC	No DR	Fast DR only
	75%+25%+10% PBFA DSM	75%+25%+10% PBFA DSM	75%+25%+10% PBFA DSM
		Hu Honua (21.5MW)	
2015	Add 20 MW PV (PP03x4)	Add 5 MW PV (HP03x5)	Add 30MW wind (MW04x3)
		Deactivate Shipman 3 (–6.8 MW)	
		Deactivate Shipman 4 (–6.7 MW)	
2016	Add 60 MW wind (PW01x2)		Add 30MW wind (MW04x3)
	Add 20 MW PV (PP03x4)		
	Fuel switch to diesel (Honolulu 8–9, Waiau 5–8, Kahe 1-6)		
2017		Add 25MW geothermal (HG01x1)	
	Add 30 MW wind (PW01x1)	Add 10MW wind (HW04x1)	Add 30MW wind (MW04x3)
	Add 20 MW PV (PP03x4)		
	Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW) or Honolulu 8/9		
2018		Add 10MW wind (HW04x1)	Add 20MW wind (MW04x2)
	Add 20 MW PV (PP03x4)		
2019	Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW) or Waiau 3/4		
2020		Add 5 MW PV (HP03x5)	
2021		Add 10MW wind (HW04x1)	
2022	Fuel switch to ULSD (Waiau 5–8, Kahe 1–6)	Fuel switch to LSIFO (Hill 5–6, Puna 1)	Fuel switch to LSIFO (Kahului 1–4,) Fuel switch to ULSD (All Maalaea)
2023			
2024			
2025			
2026			Add 10MW wind (MW04x1)
2027			

Name	PHM3B2B1NRETIRE-3BR0		
2028			
2029			
2030			
2031		Add 10MW wind (HW04x1)	Add 10MW wind (MW04x1)
2032		Add 10MW wind (HW04x1)	
2033		Add 5 MW PV (HP03x5)	
			Add 10MW wind (MW04x1)
Planning Period Total Cost	40,646,636		
Study Period Total Cost	55,452,888		

Stuck in the Middle

In Stuck in the Middle, utility scale renewable energy projects provide an increased contribution to meeting the RPS where there is load growth.

Figure 8-113. Stuck in the Middle Contribution to RPS from NEM/FIT and Renewable Generation Net of NEM/FIT

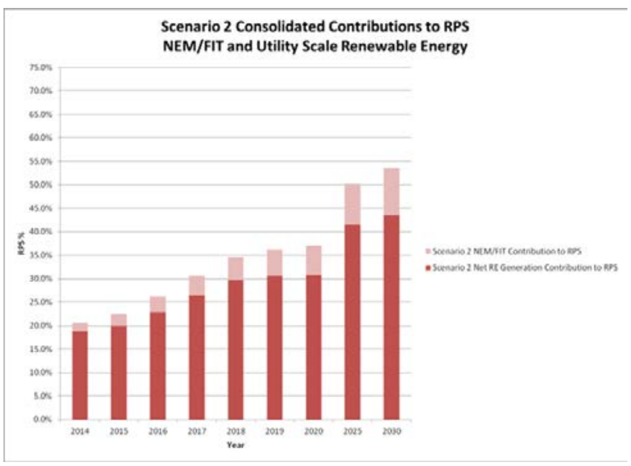


Figure 8-114. Stuck in the Middle Contribution to RPS by Company

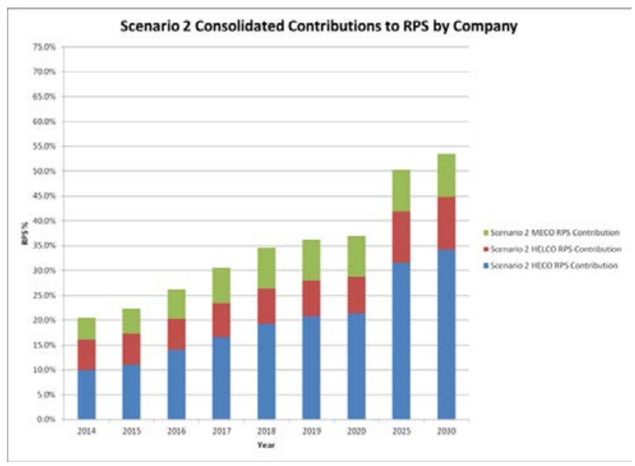


Table 8-37. Stuck in the Middle Breakdown of Sales and NEM/FIT Data (GWh)

	2014	2015	2016	2017	2018	2019	2020	2025	2030
Sales	9,407	9,442	9,542	9,542	9,534	9,577	9,617	9,717	9,880
Total RE Generation	1,934	2,117	2,501	2,916	3,296	3,460	3,556	4,876	5,287
NEM/FIT	163	236	321	394	464	531	596	845	983
Net RE Generation	1,771	1,881	2,179	2,522	2,832	2,929	2,960	4,031	4,304
NEM/FIT Contribution to RPS	1.7%	2.5%	3.4%	4.1%	4.9%	5.5%	6.2%	8.7%	10.0%
Net RE Generation Contribution to RPS	18.8%	19.9%	22.8%	26.4%	29.7%	30.6%	30.8%	41.5%	43.6%

Table 8-38. Stuck in the Middle Consolidated System Resource Plan

Name	**PHM2B2B1NRETIRE-3BR1**		
Plan	HECO Fuel Switch to ULSD in 2022	HELCO Deactivate Existing Replace with Geothermal	MECO Fuel Switch to LSIFO in 2022
Notes	Consolidated No Minimum RPS Run	Consolidated No Minimum RPS Run	Consolidated No Minimum RPS Run
Resources Available	30 MW Wind (PW01): 2017 5 MW PV (PP03): 2015	10 MW Wind (HW01): 2015 1 MW PV (HP03): 2015 25 MW Geothermal (HG01): 2017 25 MW New Site Geothermal (HG02): 2020	10 MW Wind (MW04): 2015 1 MW PV (MP03): 2015
2014	Expanded CIDLC, CIDP, RDLCWH, RDLCAC	No DR	All DR: CIDLC Exp, RDLC Exp, Fast DR
	75% PBFA DSM	75% PBFA DSM	75% PBFA DSM
		Hu Honua (21.5MW)	
2015	Add 20 MW PV (PP03x4)	Add 5 MW PV (HP03x5)	Add 30MW wind (MW04x3)
		Deactivate Shipman 3 (–6.8 MW)	
		Deactivate Shipman 4 (–6.7 MW)	
2016	Add 20 MW PV (PP03x4)		Add 30MW wind (MW04x3)
	Add 60 MW wind (PW01x2)		
	Fuel switch to diesel (Honolulu 8–9, Waiau 5–8, Kahe 1–6)		
2017	Add 60 MW wind (PW01x2)	Add 10MW wind (HW04x1)	Add 30MW wind (MW04x3)
	Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW) or Honolulu 8/9		
2018	Add 60 MW wind (PW01x2)	Add 10MW wind (HW04x1)	Add 20MW wind (MW04x2)
2019	Add 30 MW wind (PW01x1)		
	Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW) or Waiau 3/4		
2020	Add 59MW CC (PC08x1); biofuel		
2021		Add 10MW wind (HW04x1)	
2022		Add 25MW geothermal (HG01x1)	
	Fuel switch to ULSD (Waiau 5–8, Kahe 1–6)	Fuel switch to LSIFO (Hill 5–6, Puna 1)	Fuel switch to LSIFO (Kahului 1–4,) Fuel switch to ULSD (All Maalaea)
2023		Add 5 MW PV (HP03x5)	
2024	Add 200 MW Lanai Wind	Add 5 MW PV (HP03x5)	
2025			
2026		Add 5 MW PV (HP03x5)	Add 10MW wind (MW04x1)
2027	Add 25MW (PA01x1); biomass		
2028		Add 5 MW PV (HP03x5)	
2029			Add 5MW ICE (MS14x1); biodiesel

Name	PHM2B2B1NRETIRE-3BR1		
2030		Add 5 MW PV (HP03x5)	
2031		Add 10MW wind (HW04x1)	Add 10MW wind (MW04x1)
2032		Add 10MW wind (HW04x1)	
2033		Add 5 MW PV (HP03x5)	Add 10MW wind (MW04x1)
	Add 20 MW PV (PP03x4)	Add 25MW new geothermal (HG02x1)	
Planning Period Total Cost	29,961,104		
Study Period Total Cost	44,283,512		

An additional run was performed in Stuck in the Middle where Hawaiian Electric is able to fuel switch to LNG in 2020.

An additional Stuck in the Middle model switched fuels to LNG in 2020. While this fuel switch reduces the RPS, it is also cost competitive with renewable resources as new renewable resources are not added to displace existing generation. Since there is no minimum RPS requirement, renewable resource are only added when economically viable.

Figure 8-115 and Figure 8-116 together with the data in Table 8-41 show the effect of the LNG fuel switch on RPS. Table 8-42 shows the resource plan.

Figure 8-115. Stuck in the Middle with HECO LNG Fuel Switch Contribution to RPS from NEM/FIT and Renewable Generation Net of NEM/FIT

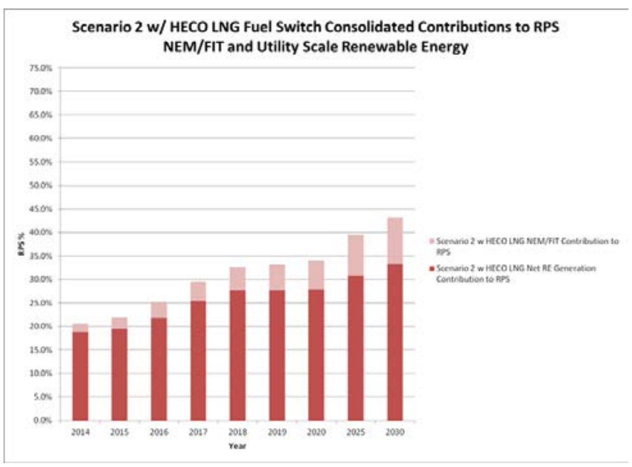


Figure 8-116. Stuck in the Middle with HECO LNG Fuel Switch Contribution to RPS by Company

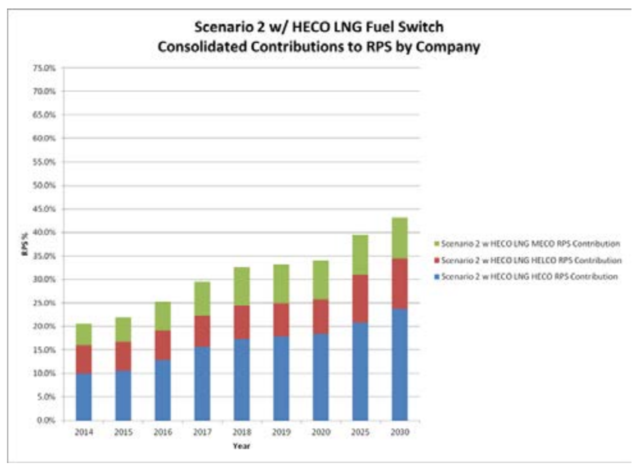


Table 8-39. Stuck in the Middle with LNG Breakdown of Sales and NEM/FIT Data (GWh)

	2014	2015	2016	2017	2018	2019	2020	2025	2030
Sales	9,407	9,442	9,542	9,542	9,534	9,577	9,617	9,717	9,880
Total RE Generation	1,934	2,069	2,404	2,820	3,107	3,177	3,273	3,832	4,269
NEM/FIT	163	236	321	394	464	531	596	845	983
Net RE Generation	1,771	1,833	2,083	2,425	2,642	2,646	2,678	2,987	3,286
NEM/FIT Contribution to RPS	1.7%	2.5%	3.4%	4.1%	4.9%	5.5%	6.2%	8.7%	10.0%
Net RE Generation Contribution to RPS	18.8%	19.4%	21.8%	25.4%	27.7%	27.6%	27.8%	30.7%	33.3%

Table 8-40. Stuck in the Middle with HECO LNG Fuel Switch Consolidated System Resource Plan

Name	**PHM2B2B1NRETIRE-3BR1 LNG**		
Plan	HECO Fuel Switch to LNG in 2020	HELCO Deactivate Existing Replace with Geothermal	MECO Fuel Switch to LSIFO in 2022
Notes	Consolidated No Minimum RPS Run	Consolidated No Minimum RPS Run	Consolidated No Minimum RPS Run
Resources Available	30 MW Wind (PW01): 2017 5 MW PV (PP03): 2015	10 MW Wind (HW01): 2015 1 MW PV (HP03): 2015 25 MW Geothermal (HG01): 2017 25 MW New Site Geothermal (HG02): 2020	10 MW Wind (MW04): 2015 1 MW PV (MP03): 2015
2014	Expanded CIDLC, CIDP, RDLCWH, RDLCAC	No DR	All DR: CIDLC Exp, RDLC Exp, Fast DR
	75% PBFA DSM	75% PBFA DSM	75% PBFA DSM
		Hu Honua (21.5MW)	
2015		Add 5 MW PV (HP03x5)	Add 30MW wind (MW04x3)
		Deactivate Shipman 3 (–6.8 MW)	
		Deactivate Shipman 4 (–6.7 MW)	
2016	Add 60 MW wind (PW01x2)		Add 30MW wind (MW04x3)
	Fuel switch to diesel (Honolulu 8–9, Waiau 5–8, Kahe 1–6)		
2017	Add 60 MW wind (PW01x2)	Add 10MW wind (HW04x1)	Add 30MW wind (MW04x3)
	Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW) or Honolulu 8/9		
2018	Add 30 MW wind (PW01x1)	Add 10MW wind (HW04x1)	Add 20MW wind (MW04x2)
2019	Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW) or Waiau 3/4		
2020	Add 59MW CC (PC08x1); biofuel		
	Fuel switch to LNG (Waiau 5–8, Kahe 1–6)		
2021		Add 10MW wind (HW04x1)	

Name	**PHM2B2B1NRETIRE-3BR1 LNG**		
2022		Add 25MW geothermal (HG01x1)	
		Fuel switch to LSIFO (Hill 5–6, Puna 1)	Fuel switch to LSIFO (Kahului 1–4,) Fuel switch to ULSD (All Maalaea)
2023			
2024		Add 5 MW PV (HP03x5)	
2025		Add 5 MW PV (HP03x5)	
2026		Add 5 MW PV (HP03x5)	Add 10MW wind (MW04x1)
2027	Add 25MW (PA01x1); biomass		
2028		Add 5 MW PV (HP03x5)	
2029			Add 5MW ICE (MS14x1); biodiesel
2030		Add 5 MW PV (HP03x5)	
2031	Add 200 MW Lanai Wind	Add 10MW wind (HW04x1)	Add 10MW wind (MW04x1)
2032		Add 10MW wind (HW04x1)	
2033		Add 5 MW PV (HP03x5)	Add 10MW wind (MW04x1)
		Add 25MW new geothermal (HG02x1)	
Planning Period Total Cost	27,198,072		
Study Period Total Cost	38,824,840		

No Burning Desire

In No Burning Desire, higher levels of RPS are difficult to achieve with high load growth. Although the model selected Lanai Wind as a resource, achieving the current RPS mandate will require significant capacity additions of renewable resources to meet the goal of 40% renewable generation by 2030. At that time, the resource plan meets the scenario RPS goal of 30%.

Figure 8-117. No Burning Desire Contribution to RPS from NEM/FIT and Renewable Generation Net of NEM/FIT

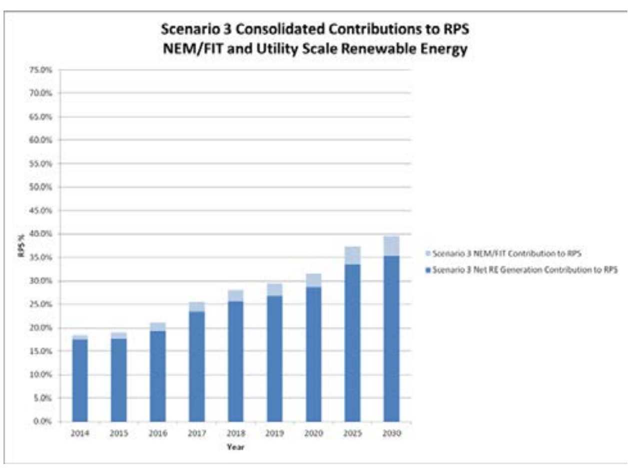


Figure 8-118. No Burning Desire Contribution to RPS by Company

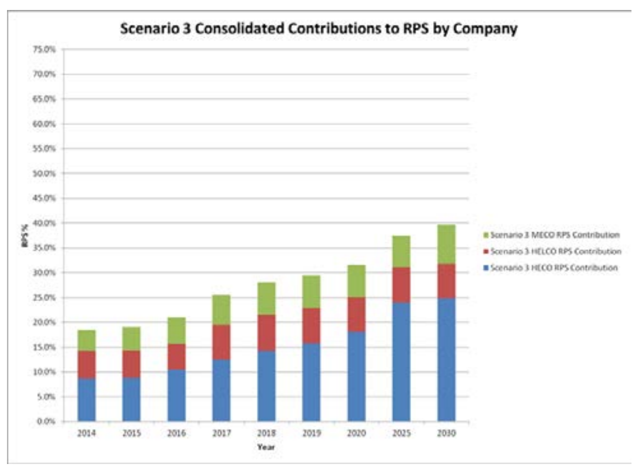


Table 8-41. No Burning Desire Breakdown of Sales and NEM/FIT Data (GWh)

	2014	2015	2016	2017	2018	2019	2020	2025	2030
Sales	10,149	10,445	10,822	11,064	11,311	11,601	11,876	12,820	13,633
Total RE Generation	1,867	1,984	2,273	2,814	3,170	3,415	3,747	4,798	5,396
NEM/FIT	95	138	188	230	271	310	348	493	574
Net RE Generation	1,771	1,846	2,086	2,585	2,899	3,105	3,399	4,305	4,822
NEM/FIT Contribution to RPS	0.9%	1.3%	1.7%	2.1%	2.4%	2.7%	2.9%	3.8%	4.2%
Net RE Generation Contribution to RPS	17.5%	17.7%	19.3%	23.4%	25.6%	26.8%	28.6%	33.6%	35.4%

Table 8-42. No Burning Desire Consolidated System Resource Plan

Name	**PHM3B2B1NRETIRE-3BR0**		
Plan	HECO Fuel Switch to ULSD in 2020	HELCO Deactivate Existing Replace with Geothermal	MECO Fuel Switch to LSIFO in 2022
Notes	Consolidated No Minimum RPS Run	Consolidated No Minimum RPS Run	Consolidated No Minimum RPS Run
Resources Available	30 MW Wind (PW01): 2017 5 MW PV (PP03): 2015	10 MW Wind (HW01): 2015 1 MW PV (HP03): 2015 25 MW Geothermal (HG01): 2017 25 MW New Site Geothermal (HG02): 2020	10 MW Wind (MW04): 2015 1 MW PV (MP03): 2015
2014	Expanded CIDLC, CIDP, RDLCWH, RDLCAC	New CIDLC, Fast DR, RDLCWH, RDLCAC	All DR: CIDLC Exp, RDLC Exp, Fast DR
	75% PBFA DSM	75% PBFA DSM	75% PBFA DSM
		Hu Honua (21.5MW)	
2015			Add 30MW wind (MW04x3)
		Deactivate Shipman 3 (–6.8 MW)	Add 15MW ICE (MS14x3); biofuel
		Deactivate Shipman 4 (–6.7 MW)	
2016	Add 60 MW wind (PW01x2)		Add 20MW wind (MW04x2)
	Add 91MW SCCT (PS07x1); biofuel		Add 21 MW SCCT (MS05x1); biofuel
	Fuel switch to diesel (Honolulu 8–9, Waiau 5–8, Kahe 1–6)		
2017	Add 60 MW wind (PW01x2)	Add 10MW wind (HW04x1)	Add 20MW wind (MW04x2)
		Add 25MW geothermal (HG01x1)	
	Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW) or Honolulu 8/9		
2018	Add 20 MW wind (PW01x2)	Add 10MW wind (HW04x1)	Add 20MW wind (MW04x2)
	Add 91MW SCCT (PS07x1); biofuel		

Name	**PHM3B2B1NRETIRE-3BR0**		
2019	Add 20 MW wind (PW01x2)		
	Add 17MW ICE (PS01x1); biofuel		Add 21 MW SCCT (MS05x1); biofuel
	Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW) or Waiau 3/4		
2020	Add 20 MW wind (PW01x2)		
	Add 182MW SCCT (PS07x2); biofuel		
	Add 20 MW PV (PP03x4)		
2021		Add 10MW wind (HW04x1)	
2022	Add 200 MW Lanai Wind		Add 17 MW ICE (MS01x1); biofuel
	Fuel switch to ULSD (Waiau 5–8, Kahe 1–6)	Fuel switch to LSIFO (Hill 5–6, Puna 1)	Fuel switch to LSIFO (Kahului 1–4,) Fuel switch to ULSD (All Maalaea)
2023			
2024	Add 91MW SCCT (PS07x1); biofuel		Add 17 MW ICE (MS01x1); biofuel
2025		Add 17 MW ICE (HS01x1); biofuel	
2026			Add 10MW wind (MW04x1)
2027			Add 25MW new geothermal (MG02x1)
2028			
2029			Add 10MW wind (MW04x1)
2030	Add 20 MW wind (PW01x2)		
2031	Add 20 MW wind (PW01x2)	Add 10MW wind (HW04x1)	Add 17 MW ICE (MS01x1); biofuel
			Add 10MW wind (MW04x1)
2032	Add 10 MW wind (PW01x1)	Add 10MW wind (HW04x1)	
2033	Add 34MW ICE (PS01x2); biofuel		
Planning Period Total Cost	31,410,302		
Study Period Total Cost	45,514,464		

Moved by Passion

In Moved by Passion, NEM/FIT continues to contribute greatly to the RPS.

Figure 119. Moved by Passion Contribution to RPS from NEM/FIT and Renewable Generation Net of NEM/FIT

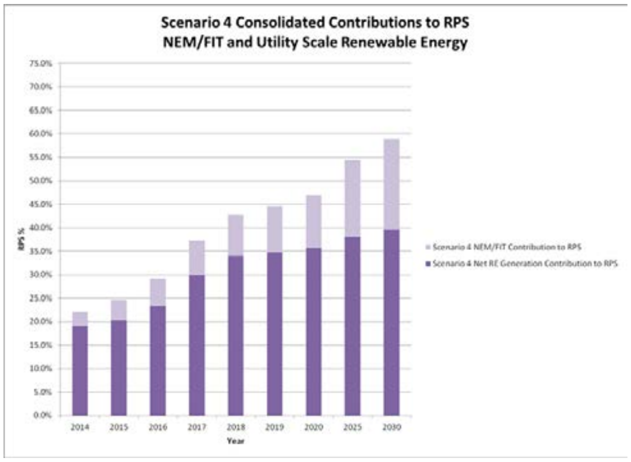


Figure 120. Moved by Passion Contribution to RPS by Company

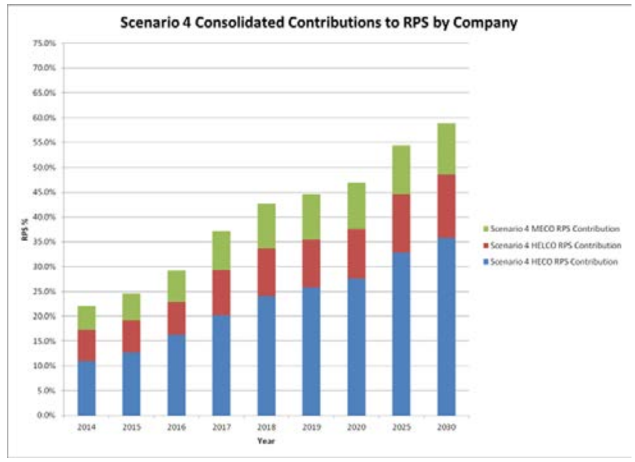


Table 8-43. Moved by Passion Breakdown of Sales and NEM/FIT Data (GWh)

	2014	2015	2016	2017	2018	2019	2020	2025	2030
Sales	9,207	9,158	9,168	9,084	8,994	8,957	8,918	8,670	8,549
Total RE Generation	2,032	2,254	2,677	3,377	3,840	3,997	4,184	4,717	5,033
NEM/FIT	275	396	539	660	778	890	998	1,416	1,648
Net RE Generation	1,757	1,858	2,138	2,717	3,062	3,107	3,186	3,301	3,385
NEM/FIT Contribution to RPS	3.0%	4.3%	5.9%	7.3%	8.6%	9.9%	11.2%	16.3%	19.3%
Net RE Generation Contribution to RPS	19.1%	20.3%	23.3%	29.9%	34.0%	34.7%	35.7%	38.1%	39.6%

Table 8-44. Moved by Passion Consolidated System Resource Plan

Name	**PHM4B2B1NRETIRE-3BR0**		
Plan	HECO Fuel Switch to ULSD in 2020	HELCO Deactivate Existing Replace with Geothermal	MECO Fuel Switch to LSIFO in 2022
Notes	Consolidated No Minimum RPS Run	Consolidated No Minimum RPS Run	Consolidated No Minimum RPS Run
Resources Available	30 MW Wind (PW01): 2017 5 MW PV (PP03): 2015	10 MW Wind (HW01): 2015 1 MW PV (HP03): 2015 25 MW Geothermal (HG01): 2017 25 MW New Site Geothermal (HG02): 2020	10 MW Wind (MW04): 2015 1 MW PV (MP03): 2015
2014	Expanded CIDLC, CIDP, RDLCWH, RDLCAC	No DR	Fast DR only
	75%+25% PBFA DSM	75%+25% PBFA DSM	75%+25% PBFA DSM
		Hu Honua (21.5MW)	
2015	Add 20 MW PV (PP03x4)	Add 5 MW PV (HP03x5)	Add 30MW wind (MW04x3)
		Deactivate Shipman 3 (–6.8 MW)	
		Deactivate Shipman 4 (–6.7 MW)	
2016	Add 60 MW wind (PW01x2)		Add 30MW wind (MW04x3)
	Add 20 MW PV (PP03x4)		
	Fuel switch to diesel (Honolulu 8–9, Waiau 5–8, Kahe 1–6)		
2017		Add 25MW geothermal (HG01x1)	
	Add 60 MW wind (PW01x2)	Add 10MW wind (HW04x1)	Add 30MW wind (MW04x3)
	Add 20 MW PV (PP03x4)		
	Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW) or Honolulu 8/9		
2018	Add 60 MW wind (PW01x2)	Add 10MW wind (HW04x1)	Add 20MW wind (MW04x2)
	Add 20 MW PV (PP03x4)		
2019	Add 20 MW PV (PP03x4)		
	Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW) or Waiau 3/4		
2020	Add 20 MW PV (PP03x4)	Add 5 MW PV (HP03x5)	
2021		Add 5 MW PV (HP03x5)	
		Add 10MW wind (HW04x1)	
2022	Fuel switch to ULSD (Waiau 5–8, Kahe 1–6)	Fuel switch to LSIFO (Hill 5–6, Puna 1)	Fuel switch to LSIFO (Kahului 1–4,) Fuel switch to ULSD (All Maalaea)
2023			
2024		Add 5 MW PV (HP03x5)	
2025			
2026			Add 10MW wind (MW04x1)

Name	**PHM4B2B1NRETIRE-3BR0**		
2027			
2028		Add 5 MW PV (HP03x5)	
2029		Add 5 MW PV (HP03x5)	
2030			
2031		Add 10MW wind (HW04x1)	Add 10MW wind (MW04x1)
2032		Add 10MW wind (HW04x1)	
2033	Add 200 MW Lanai Wind		
		Add 25MW new geothermal (HG02x1)	
			Add 10MW wind (MW04x1)
Planning Period Total Cost	31,618,530		
Study Period Total Cost	44,813,444		

Consolidated Analysis Conclusion

The RPS growth across all three utilities in all four scenarios suggests that the current RPS law can be achieved. In 2030, the RPS contribution by utility scale projects ranged from 33.3% to 43.6%; and from NEM/FIT, it ranged from 4.2% to 30.3%. Meeting the current RPS law, regardless of the scenario future, will require a contribution from a growing NEM/FIT program. Figure 8-121 and Figure 8-122 show a consolidated RPS comparison between 2015 and 2030.

Figure 8-121. Consolidated RPS Snapshot in 2015

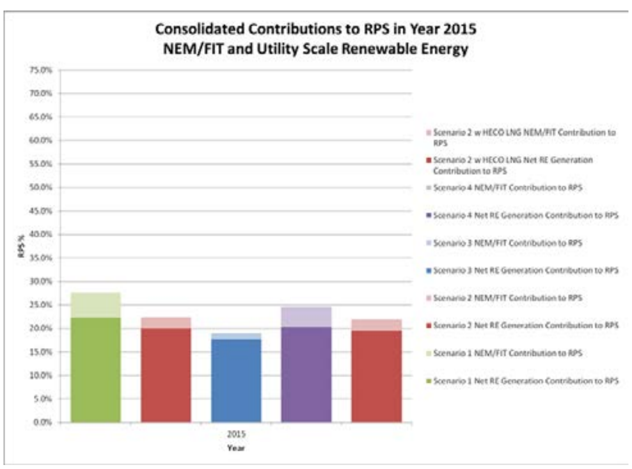
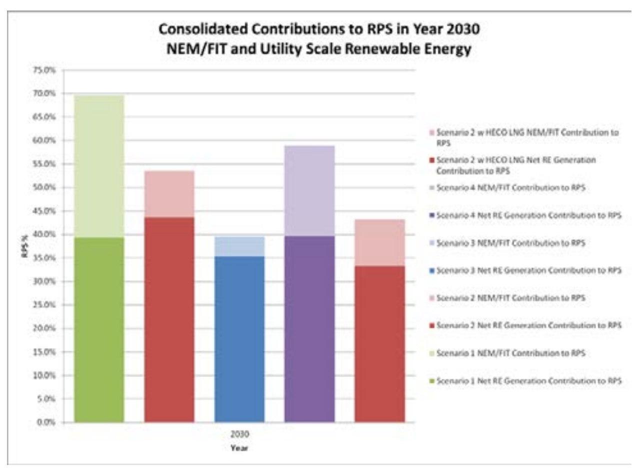


Figure 8-122. Consolidated RPS Snapshot in 2030



Fuel Supply and Infrastructure Analysis

In early 2013, the Companies submitted a Fuels Master Plan (FMP) to the Commission. The plan outlines a solution for ensuring adequate and timely supply of fossil fuels necessary to meet the electricity demands for Company ratepayers, reliably, cost-effectively, and environmentally compliant. See *Appendix I: Hawaiian Electric Companies Fuels Master Plan* for the complete report.

Analysis of Upgrading Fossil Fuel Generation

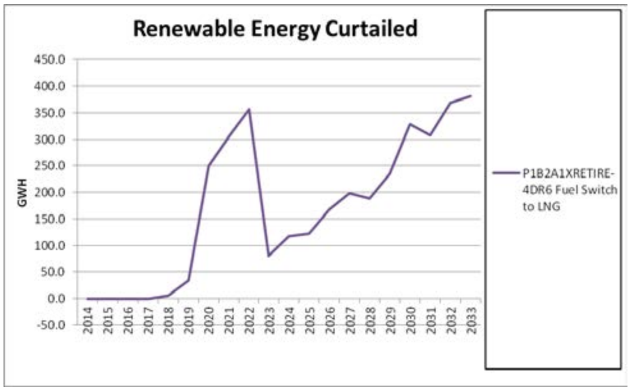
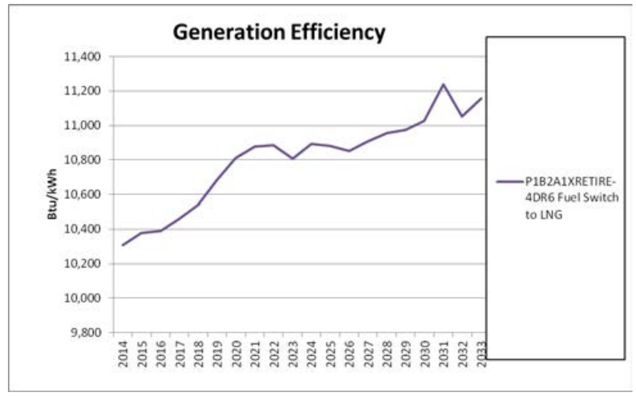
The level of wind energy curtailment during light load hours (when thermal units are at lower power output and perhaps against the down reserve requirement) is influenced by the amount of down regulation and the system's total minimum capacity of the base loaded generation units

The Oahu Wind Integration Study extensively analyzed this issue, and found that reducing the minimum power of the thermal units increases the amount of wind energy that can be accepted during light load conditions. The primary wind energy curtailment factor is associated with thermal units backed down to minimum power (respecting the down reserve requirement) at light load and high wind conditions.

Several the resource plans included cycling of base loaded units. The effect of cycling units is examine in resource plan P1B2a1xRetire-4Dr6 which converts the base loaded Kahe 1 through 4 units to cycling operation in 2023 and the Kahe 6 and Waiau 7 units in 2030.

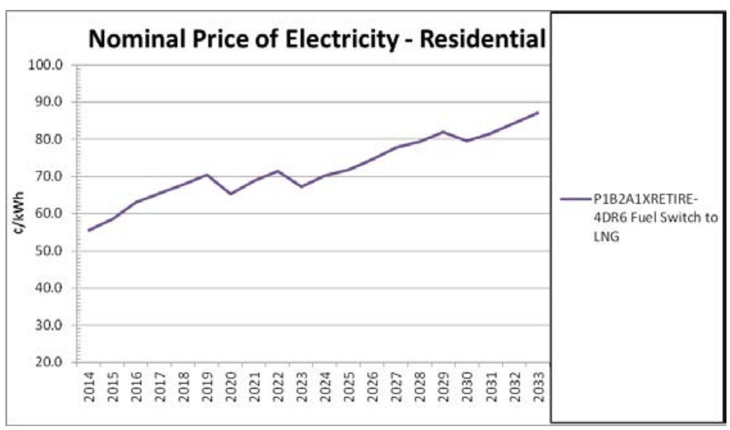
Figure 8-123 shows how cycling reduces curtailed renewable energy from 2022 to 2023 when Kahe units 1 through 4 are cycled, and again from 2029 to 2030 when Kahe 6 and Waiau 7 are cycled. Cycling of former base loaded units allows them to be shut off during times of low energy demand to lower the system's minimum capacity allowing the system to accommodate more renewable wind generation.

Cycling units can also improve system efficiency or lower heat rate (Figure 8-124)—lower is better.

Figure 8-123. Potential Benefit on Renewable Energy Curtailment by Cycling Kahe 1–4 in 2023 and Kahe 6 and Waiau 7 in 2030	Figure 8-124. Potential Benefit on Generation Efficiency by Cycling Kahe Units 1–4 in 2023 and Kahe 6 and Waiau 7 in 2030
	

The efficiency improves (goes down) between 2022 and 2023 and again between 2029 and 2030. Fewer base load units makes other based loaded units operate at higher, more efficient load levels resulting in improved system efficiency, which in turn, contributes to lower rates (Figure 8-125).

Figure 8-125. Potential Impact on Residential Rates) by Cycling Kahe 1–4 in 2023 and Kahe 6 and Waiau 7 in 2030



Because of the potential benefits, Hawaiian Electric is implementing projects to increase operational flexibility of its base loaded units including lowering of their minimum load capability or converting base load units to being capable of cycling operation.

Chapter 9: Environmental Regulation Compliance

Environmental legislation, regulations, and governmental rules have increased dramatically in recent years, especially regarding air (Clean Air Act) and water (Clean Water Act). The Companies must comply with these environmental requirements which focus on four main areas:

- Mercury and Air Toxics Standards (MATS)
- National Ambient Air Quality Standards (NAAQS)
- Regional Haze Rule
- Reciprocating Internal Combustion Engines National Emission Standards for Hazardous Air Pollutants (RICE NESHAP) Rule

Hawaiian Electric focused its analysis on MATS and NAAQS compliance, while MECO and HELCO focused their analysis on NAAQS compliance.

Environmental Compliance Alternatives

The Hawaiian Electric Companies must comply with environmental laws and regulations that govern how existing facilities are operated, new facilities are constructed and operated, and hazardous waste and toxic substances are cleaned up and disposed.

Complying with air and water pollution regulations could require the Companies to commit significant capital and annual expenditures.

Mercury and Air Toxics Standards (MATS)

The Environmental Protection Agency (EPA) published the Mercury and Air Toxics Standards (MATS) final rule on February 16, 2012**.** MATS established emissions limits for hazardous air pollutants (HAP metals and acid gases) for fossil-fuel fired steam electrical generating units. Filterable particulate matter (PM) may be used as a compliance surrogate for the HAP metals limit and fuel moisture content as a compliance surrogate for the acid gases. This rule applies to the fourteen Hawaiian Electric steam generating units at the Honolulu, Kahe, and Waiau generating stations.

Particulate matter emission can be controlled by reducing the amount of unburned carbon produced by the combustion process, by reducing the ash and sulfur content in the fuel, or by installing a PM control device. An electrostatic precipitator (ESP) is a PM control device that traps and removes PM produced by boilers.

Hawaiian Electric is required to comply with MATS by April 16, 2015, although that deadline might be extended for two years by means of two separate one-year extensions. The first one-year extension is broadly available, although it requires DOH approval. A second one-year extension must be by administrative order and requires EPA approval.

National Ambient Air Quality Standards (NAAQS)

In 2010, the EPA established two new, significantly more stringent, one-hour air quality standards for nitrogen dioxide (NO_2) and sulfur dioxide (SO_2). These standards apply to all sources in the state, which includes all Hawaiian Electric, HELCO, and MECO generating stations.

Sulfur dioxide emissions can be controlled by either reducing the sulfur content in the fuel or by installing scrubbers coupled with ESPs to remove sulfur from exhaust gases. ESPs integrated with scrubbers can remove sub-micron droplets, acid mists, metals, and mercury particles. These controls also remove pollutants regulated by the MATS Rule and thus would comply with the MATS rule.

Nitrogen oxides (NOx) — nitric oxide (NO) and nitrogen dioxide (NO_2) — emissions can be controlled by combustion hardware improvements such as low NOx burners and overfire air.

EPA's SO_2 NAAQS Implementation Strategy

EPA's paper *Next Steps for Area Designations and Implementation of the Sulfur Dioxide National Ambient Air Quality Standard* (dated February 6, 2013) describes their updated one-hour SO_2 NAAQS implementation strategy. This strategy anticipates additional EPA rules and guidance, and addresses areas not currently proposed to be designated as nonattainment areas based on air monitoring data from 2009–2011.[47]

EPA's updated strategy complements the initial nonattainment area designations targeted for June 2013 based on monitoring[48], and provides flexibility for states to determine if air quality is best characterized by monitoring or modeling, or a mix of both.

EPA is expected to complete its modeling-based demonstrations in 2017, after the MATS compliance date of April 2015 (or April 2016 if a one-year extension is requested and granted). The modeling is expected to use actual (not potential-to-emit) emissions from recent years for designation purposes. Monitoring is expected to begin in January 2017 after the MATS compliance date of April 2015 (or April 2016 if a one-year extension is requested and granted).

To facilitate their dual-pathway approach, EPA will issue updated rules and guidance documents for developing acceptable SO_2 monitoring and modeling plans for designation purposes. The rulemaking will establish a process for air agencies to identify which source or source regions will be monitored and which will be modeled. EPA suggests using emission thresholds to determine whether a state should use all monitoring, all modeling, or a combination to support their designation process. The rulemaking will also outline relevant milestones for implementing the SO_2 designations strategy, including deadlines for air agencies to recommend nonattainment boundaries based on the characterization of air quality.

Air agencies will also work with sources by establishing and submitting to EPA enforceable emission limitations that ensure that the SO_2 NAAQS can be attained before the date that final designations are issued. See Figure 9-3. on page 9-14 for the anticipated timeline for implementing the one-hour SO_2 NAAQS.

[47] EPA is not prepared to propose designation action in Hawaii. The agency is deferring action to designate areas in Hawaii while it continues to assess Hawaii's request to exclude air quality monitoring data that exceeds the 2010 SO_2 standard under the Exceptional Events Rule due to SO_2 emissions from an active volcano (as stated in an EPA letter to Governor Neil Abercrombie, February 6, 2013).

[48] EPA is not intending to designate as nonattainment any areas outside the Continental United States. For information, see http://www.epa.gov/airquality/sulfurdioxide/designations/pdfs/ 20130207map.pdf

Regional Haze

Regional haze is essentially impaired visibility caused by human emissions and natural processes spread over a wide geographic area. The Clean Air Act required EPA to issue regulations to restore visibility to levels that would exist as if there were no human-made emissions—"natural visibility"—especially to national parks and wilderness areas.

EPA issued a Regional Haze Rule requiring states to establish interim goals toward attaining the final goal of natural visibility by 2064. EPA worked closely with Hawaii to develop a Regional Haze Federal Implementation Plan (FIP) which became effective on November 8, 2012.

The FIP establishes an annual SO_2 emissions cap from HELCO's three steam boiler facilities at Shipman, Hill, and Puna. The FIP provides flexibility for the utility to meet this cap by implementing measures such as energy conservation, using renewable energy, retiring units, or changing the sulfur content of the boiler fuel. The FIP requires HELCO to comply with the cap by December 31, 2018.

RICE and Greenhouse Gas Compliance

HELCO and MECO implemented steps to comply with the Reciprocating Internal Combustion Engines National Emission Standards for Hazardous Air Pollutants (RICE NESHAP) deadline of May 2013. The RICE NESHAP rule required retrofitting catalytic emission controls.

All three utilities will comply with the EPA's Greenhouse Gas reduction requirements by January 1, 2020.

Former Molokai Electric Company Generation Site

In 1989, MECO acquired by merger Molokai Electric Company. Molokai Electric Company had sold its former generation site in 1983, but continued to operate under a lease until 1985. The EPA has since performed Brownfield assessments of the generation site that identified environmental impacts in the subsurface. Although operations there stopped four years before the merger, in discussions with the EPA and the State of Hawaii Department of Health (DOH), MECO agreed to conduct further investigations at the generation site and at an adjacent parcel that Molokai Electric Company had used for equipment storage to determine the extent of impacts of subsurface contaminants. A 2011 assessment by a MECO contractor of the adjacent parcel identified environmental impacts, including elevated polychlorinated biphenyls (PCBs) in the subsurface soils. MECO continues to investigate the generation site and the adjacent parcel to determine the extent of impacts of PCBs, fuel oils, and other subsurface contaminants. In March 2012, MECO accrued an additional $3.1 million (reserve balance of $3.6 million as of March 31, 2013) for the additional investigation and estimated cleanup costs at the site and the adjacent parcel. Final costs of remediation, however, will depend on the results of the continued investigation.

Estimated Capital Costs

The capital costs for installing and operating scrubbers and ESPs at the ten Hawaiian Electric Kahe and Waiau generating units to comply with the MATS and NAAQS rules is approximately $975 million. (Hawaiian Electric has assumed the Honolulu Power Plant and Waiau 3 & 4 generating units would be retired by 2020.)

Installing and operating scrubbers and ESPs at three HELCO generating units (Hill 5, Hill 6, and Puna) would cost approximately $209 million; at four MECO Kahului generating units, costs would be approximately $221 million.

Thus, the total cost for implementing air quality control (AQC) equipment to comply with the required environmental regulations is approximately $1.4 billion.

An alternative to installing AQC equipment is switching to lower sulfur fuels. For Hawaiian Electric's boilers, preliminary analysis indicates switching to 0.5% S diesel would comply with MATS. There are no costs associated with the Honolulu Power Plant because the Companies are assuming it to be retired before 2020.

Table 9-1: Capital Costs for Fuel Switch for MATS & NAAQS Compliance

Unit	Kahe	Waiau	Honolulu	BPTF
Capital Cost	$21,164,595	$13,982,450	—	$40,277,929
Year in Service	2016	2016	—	2016

Switching to liquefied natural gas (LNG) or 0.05% S diesel would comply with the NAAQS. There will be costs to convert existing equipment to use LNG. In addition, there will be costs associated with constructing new units that use LNG.

Table 9-2: Construction Costs for LNG Fuel Conversion

Unit	HECO	HECO	HELCO	MECO
Construction	LNG Conversion	LNG New	LNG Conversion	LNG Conversion
Capital Cost	$370,000,000	$105,000,000	$8,000,000	$12,000,000
Year in Service	2020	2020	2020	2020

For HELCO and MECO boilers, preliminary analyses indicate switching to 0.75% S Industrial Fuel Oil (IFO) would comply with the one-hour SO_2 NAAQS. For MECO's Maalaea units, preliminary analysis indicates switching to 0.05% S diesel would comply with the one-hour SO_2 NAAQS.

Besides analyzing the costs for switching fuels and installing AQC equipment, the Companies also analyzed the costs associated with deactivating units and replacing them with new generation using LNG or, in some cases, with biofuels.

Finally, the Companies will update these preliminary analyses according to the rules and technical guidance documents that EPA will be issuing per their February 6, 2013 SO_2 NAAQS implementation strategy document.

Fuel Pricing Projections

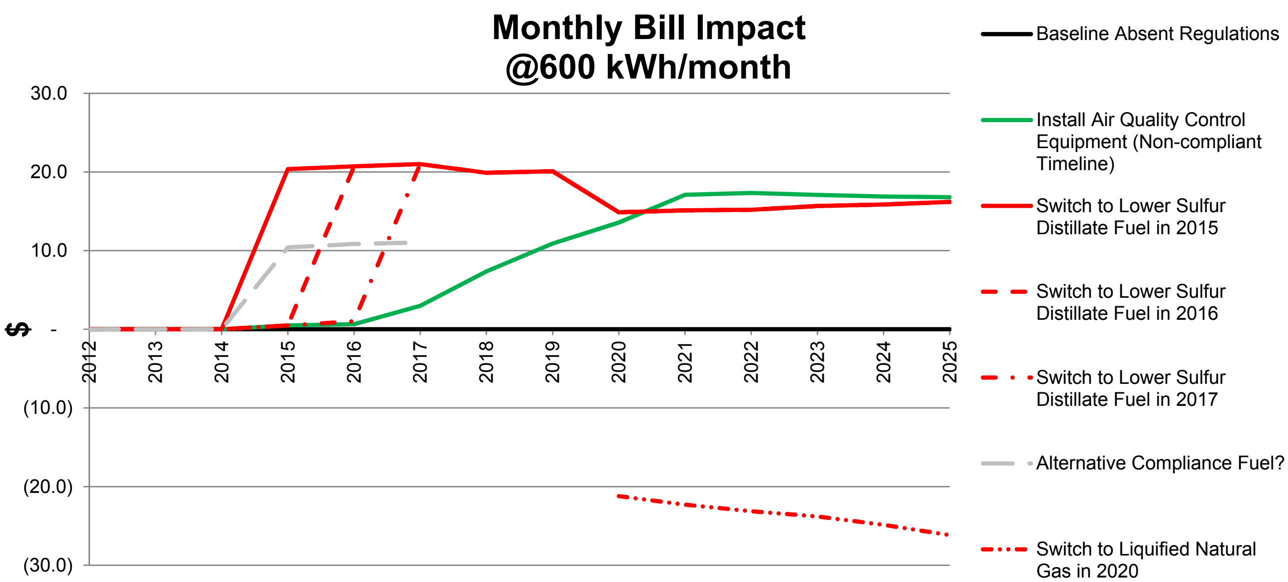
Integral to our analysis were the projected prices of potential fuels necessary to comply with these environmental standards. The projected 2015–2020 fuel prices are:

- Low Sulfur Diesel: $28–31 per MMBtu
- Low Sulfur Fuel Oil: $22–24 per MMBtu
- Liquid Natural Gas: $16 per MMBtu (2020 projection)

Environmental Compliance Impacts

Complying with the EPA environmental standards will take time, money, and management of generation — all of which exacts a cost of construction and implementation. This, of course, would have a direct impact on ratepayer bills. Figure 9- illustrates the impact that complying with the environmental regulations could have on monthly Hawaiian Electric ratepayer bills.

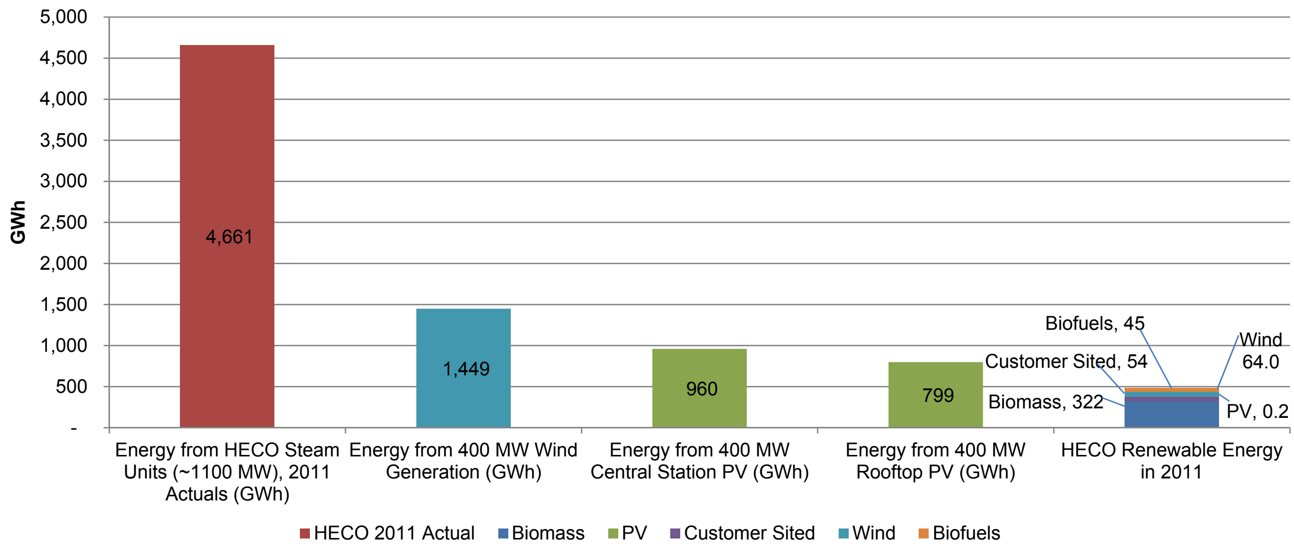
Figure 9-1. Illustration of Impact on Monthly Ratepayer Bill



Upgrading existing generation units to comply with the EPA's environmental standards is one path toward meeting these goals. Replacing units is another option. Replacing existing generation with more environmentally friendly generation would have an enormous impact on Hawaiian Electric and on its ratepayers, as the amount of generation is extremely large and diverse.

Without consideration of capacity needs, system stability, and reliability, Figure 9-2 depicts the size of such an endeavor.

Figure 9-2. Magnitude of Replacement Energy



Back-End Controls Costs for Scrubbers and ESPs

Back-end controls costs consist of capital costs to install the control hardware, costs for ongoing operations and maintenance, and costs for the treatment and disposal of any waste streams generated by the back-end controls.

Hawaiian Electric: Ten Oil-Fired Units — Kahe and Waiau

The emission control technologies for all ten Hawaiian Electric oil-fired units are electrostatic precipitators (ESPs) for removing particulate matter and semi-dry scrubbers for removing sulfur dioxide (SO_2).

Table 9-3. Back-end Controls Costs for Six HECO Kahe Oil-Fired Units

	Kahe 1	Kahe 2	Kahe 3	Kahe 4	Kahe 5	Kahe 6	Kahe Totals
Generating Capacity, MW	**92**	**92**	**92**	**92**	**142**	**142**	**652**
Major Equipment	**$31,000,000**	**$32,200,000**	**$31,600,000**	**$32,200,000**	**$48,900,000**	**$50,800,000**	**$226,700,000**
ESP and Associated Work	$5,800,000	$6,000,000	$5,900,000	$6,000,000	$9,100,000	$9,400,000	$42,200,000
Scrubber with Lime Handling Equipment	$10,900,000	$11,300,000	$11,100,000	$11,300,000	$17,200,000	$17,900,000	$79,700,000
Balance Draft Conversion	$4,000,000	$4,200,000	$4,100,000	$4,200,000	$6,300,000	$6,600,000	$29,400,000
Electric	$5,200,000	$5,400,000	$5,300,000	$5,400,000	$8,300,000	$8,600,000	$38,200,000
Mechanical	$5,100,000	$5,300,000	$5,200,000	$5,300,000	$8,000,000	$8,300,000	$37,200,000
Construction	**$38,500,000**	**$39,900,000**	**$39,100,000**	**$39,900,000**	**$60,300,000**	**$62,500,000**	**$280,200,000**
ESP and Associated Work	$24,300,000	$25,200,000	$24,700,000	$25,200,000	$38,200,000	$39,600,000	$177,200,000
Balance Draft Conversion	$8,400,000	$8,700,000	$8,500,000	$8,700,000	$13,100,000	$13,600,000	$61,000,000
Scrubber and Associated Work	$5,800,000	$6,000,000	$5,900,000	$6,000,000	$9,000,000	$9,300,000	$42,000,000
Engineering & Permitting	**$7,000,000**	**$7,100,000**	**$7,000,000**	**$7,100,000**	**$10,800,000**	**$10,800,000**	**$49,800,000**
Allowance for Funds Used During Construction (AFUDC)	**$7,800,000**	**$5,900,000**	**$8,200,000**	**$8,400,000**	**$9,400,000**	**$9,800,000**	**$49,500,000**
Total	**$84,300,000**	**$85,100,000**	**$85,900,000**	**$87,600,000**	**$129,400,000**	**$133,900,000**	**$606,200,000**

Table 9-4. Back-end Controls Costs for Four HECO Waiau Oil-Fired Units

	Waiau 5	Waiau 6	Waiau 7	Waiau 8	Waiau Totals	Grand Total
Generating Capacity, MW	**58**	**58**	**92**	**92**	**300**	**952**
Major Equipment	**$26,600,000**	**$25,000,000**	**$42,800,000**	**$42,800,000**	**$137,200,000**	**$363,900,000**
ESP and Associated Work	$5,100,000	$4,800,000	$8,200,000	$8,200,000	$26,300,000	$68,500,000
Scrubber with Lime Handling Equipment	$9,100,000	$8,600,000	$14,700,000	$14,700,000	$47,100,000	$126,800,000
Balance Draft Conversion	$5,300,000	$5,000,000	$8,600,000	$8,600,000	$27,500,000	$56,900,000
Electrical	$4,300,000	$4,000,000	$6,800,000	$6,800,000	$21,900,000	$60,100,000
Mechanical	$2,800,000	$2,600,000	$4,500,000	$4,500,000	$14,400,000	$51,600,000
Construction	**$33,600,000**	**$31,800,000**	**$54,400,000**	**$54,400,000**	**$174,200,000**	**$454,400,000**
ESP and Associated Work	$19,500,000	$18,400,000	$31,500,000	$31,500,000	$100,900,000	$278,100,000
Balance Draft Conversion	$8,600,000	$8,200,000	$14,000,000	$14,000,000	$44,800,000	$105,800,000
Scrubber and Associated Work	$5,500,000	$5,200,000	$8,900,000	$8,900,000	$28,500,000	$70,500,000
Engineering and Permitting	**$5,000,000**	**$4,800,000**	**$7,900,000**	**$7,900,000**	**$25,600,000**	**$75,400,000**
Allowance for Funds Used During Construction (AFUDC)	**$6,600,000**	**$6,800,000**	**$8,000,000**	**$10,100,000**	**$31,500,000**	**$81,000,000**
Total	**$71,800,000**	**$68,400,000**	**$113,100,000**	**$115,200,000**	**$368,500,000**	**$974,700,000**

Legend for Hawaiian Electric Tables

Entry	Explanation
ESP and Associated Work	Includes installing the Electrostatic Precipitator and its ash handling equipment; plus ‘Electrical’ which includes installing the burner management system, Continuous Emission Monitoring System (CEMS), control system upgrades, wiring, instrumentation, lighting, and power; plus ‘Miscellaneous’ which includes installing all structural steel, concrete foundations, buildings, HVAC, piping, earthwork, and fire protection
Balance Draft Conversion	Includes installing induced draft and forced draft fans, duct work, insulation, boiler stiffening, and the combined stack (Waiau only) to convert the units from a forced draft to a balance draft system
Scrubber and Associated Work	Includes installing the scrubber and its lime handling equipment, plus all ‘Electrical’ and ‘Miscellaneous’ costs
Engineering and Permitting	Includes Hawaiian Electric’s labor; permitting costs; consultant engineering; construction management; start-up, testing, and commissioning; and project closeout

HELCO: Three Oil-Fired Units — Hill and Puna

The emission control technologies for the HELCO oil-fired units are electrostatic precipitators (ESPs) for removing particulate matter and semi-dry scrubbers for removing sulfur dioxide (SO_2).

Table 9-5 shows the costs for implementing the environmental technologies at the three HELCO oil-fired Hill and Puna units.

Table 9-5. Back-end Controls Costs for Three HELCO Oil-Fired Units

	Hill 5	Hill 6	Puna	Totals
Generating Capacity, MW	**15.5**	**25.0**	**15.5**	**56.0**
Major Equipment	**$26,700,000**	**$26,700,000**	**$28,200,000**	**$81,600,000**
Scrubber and ESP	$14,500,000	$14,500,000	$15,100,000	$44,100,000
Balance Draft Conversion	$3,300,000	$3,300,000	$3,600,000	$10,200,000
Common Ash and Lime Handling	$5,900,000	$5,900,000	$6,300,000	$18,100,000
Electrical	$2,200,000	$2,200,000	$2,300,000	$6,700,000
Miscellaneous	$800,000	$800,000	$900,000	$2,500,000
Construction	**$35,500,000**	**$35,500,000**	**$38,100,000**	**$109,100,000**
Scrubber and ESP	$15,300,000	$15,300,000	$15,300,000	$45,900,000
Balance Draft Conversion	$7,500,000	$7,500,000	$7,500,000	$22,500,000
Common Ash and Lime Handling	$9,200,000	$9,200,000	$9,200,000	$27,600,000
Electrical and Miscellaneous	$3,500,000	$3,500,000	$6,100,000	$13,100,000
Engineering and Permitting	**$4,100,000**	**$4,100,000**	**$4,800,000**	**$13,000,000**
Allowance for Funds Used During Construction (AFUDC)	**$2,100,000**	**$2,100,000**	**$900,000**	**$5,100,000**
Total	**$68,400,000**	**$68,400,000**	**$72,000,000**	**$208,800,000**

MECO: Four Oil-Fired Units — Kahului

The emission control technologies for the MECO oil-fired units are electrostatic precipitators (ESPs) for removing particulate matter and semi-dry scrubbers for removing sulfur dioxide (SO_2). Table 9-6 shows the costs for implementing the environmental technologies at the four MECO oil-fired units, Kahului 1–4.

Table 9-6. Back-end Controls Costs for Four MECO Oil-Fired Units

	Kahului 1	Kahului 2	Kahului 3	Kahului 4	Totals
Generating Capacity, Net MW	**5.62**	**5.77**	**12.15**	**12.38**	**35.92**
Generating Capacity, Gross MW	**5.0**	**5.0**	**11.5**	**12.5**	**34.0**
Major Equipment	**$21,500,000**	**$21,500,000**	**$21,500,000**	**$21,500,000**	**$86,000,000**
Scrubber and ESP	$13,400,000	$13,400,000	$13,400,000	$13,400,000	$53,600,000
Balance Draft Conversion	$3,300,000	$3,300,000	$3,300,000	$3,300,000	$13,200,000
Common Ash and Lime Handling	$2,700,000	$2,700,000	$2,700,000	$2,700,000	$10,800,000
Electrical	$1,500,000	$1,500,000	$1,500,000	$1,500,000	$6,000,000
Miscellaneous	$600,000	$600,000	$600,000	$600,000	$2,400,000
Construction	**$28,400,000**	**$28,400,000**	**$28,400,000**	**$28,400,000**	**$113,600,000**
Scrubber and ESP	$12,200,000	$12,200,000	$12,200,000	$12,200,000	$48,800,000
Balance Draft Conversion	$6,000,000	$6,000,000	$6,000,000	$6,000,000	$24,000,000
Common Ash and Lime Handling	$7,300,000	$7,300,000	$7,300,000	$7,300,000	$29,200,000
Electrical and Miscellaneous	$2,900,000	$2,900,000	$2,900,000	$2,900,000	$11,600,000
Engineering and Permitting	**$4,100,000**	**$4,100,000**	**$4,100,000**	**$4,100,000**	**$16,400,000**
Allowance for Funds Used During Construction (AFUDC)	**$1,200,000**	**$1,200,000**	**$1,200,000**	**$1,200,000**	**$4,800,000**
Total	**$55,200,000**	**$55,200,000**	**$55,200,000**	**$55,200,000**	**$220,800,000**

Legend for HELCO and MECO Tables

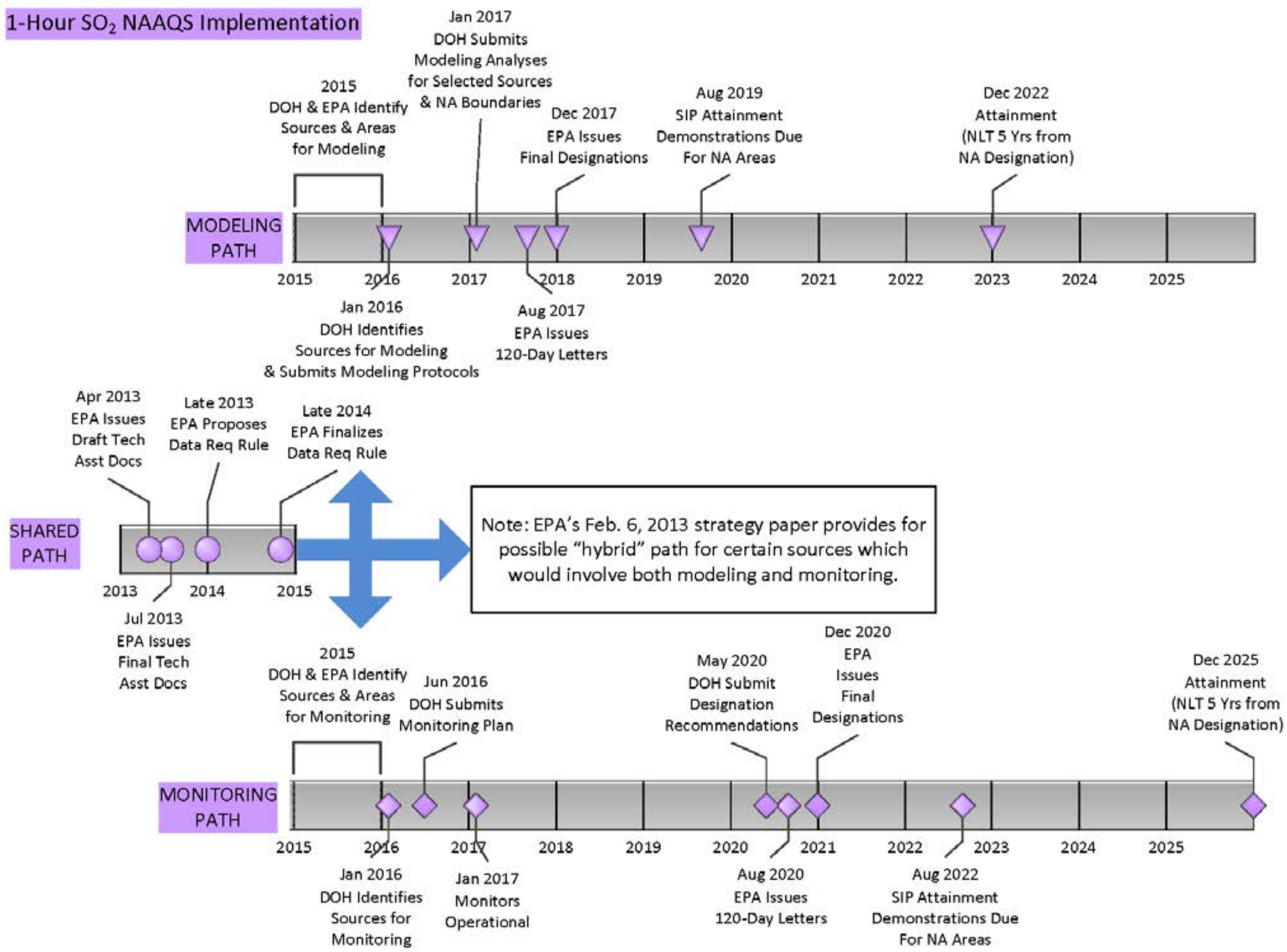
Entry	**Explanation**
Scrubber and ESP	Includes installing the scrubber and the Electrostatic Precipitator
Balance Draft Conversion	Includes installing induced draft and forced draft fans, duct work, insulation, and boiler stiffening
Common Ash and Lime Handling	Includes installing ash and lime handling equipment for the site
Electrical	Includes installing the burner management system, Continuous Emission Monitoring System (CEMS), control system upgrades, wiring, instrumentation, lighting, and power
Miscellaneous	Includes installing all structural steel, concrete foundations, buildings, HVAC, piping, earthwork, and fire protection
Engineering and Permitting	Includes the utilities' labor; permitting costs; consultant engineering; construction management; start-up, testing, and commissioning; and project closeout

Implementation Schedules

NAAQS Implementation Schedule

This implementation schedule is based on EPA's updated implementation strategy, *Next Steps for Area Designations and Implementation of the Sulfur Dioxide National Ambient Air Quality Standard* (February 6, 2013) which does not reflect any final agency action nor impose any legally binding or enforceable requirements. The timeline and milestones are subject to change.

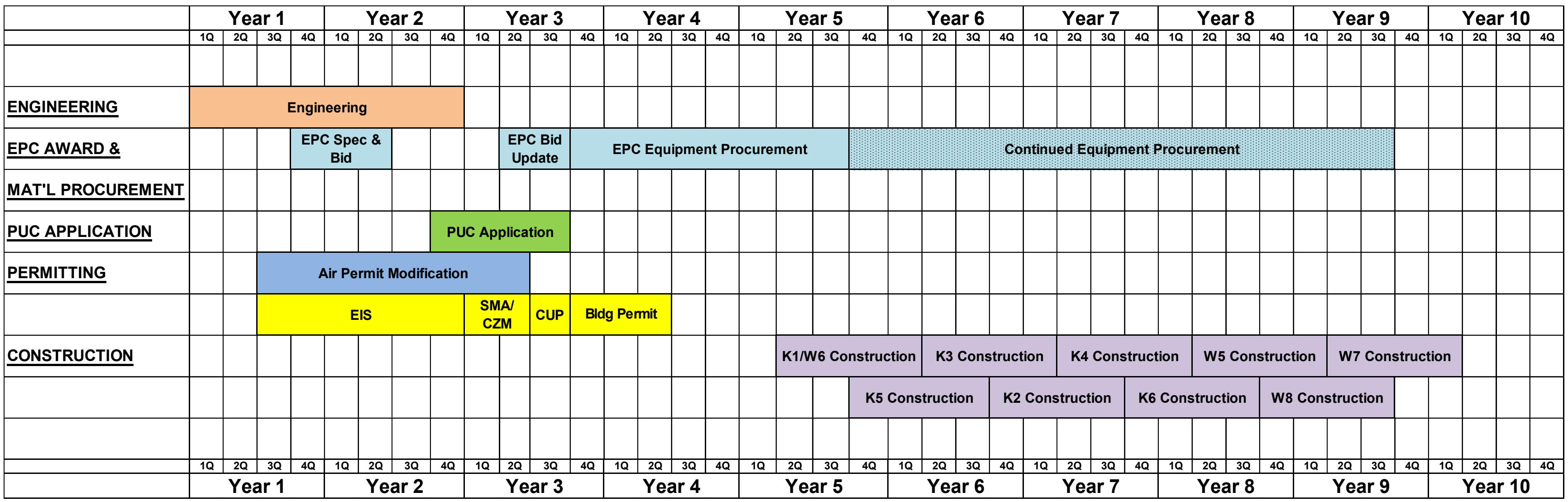
Figure 9-3. One-Hour Sulfur Dioxide NAAQS Implementation Schedule



Hawaiian Electric Schedule for Kahe and Waiau

The schedule begins first quarter 2013 (Year 1) and is projected to conclude second quarter 2022 (Year 10). The schedule assumes a lead-time for equipment of two years, for construction to take one year per unit, and that construction will be staggered due to system demand. The process presents significant permitting challenges.

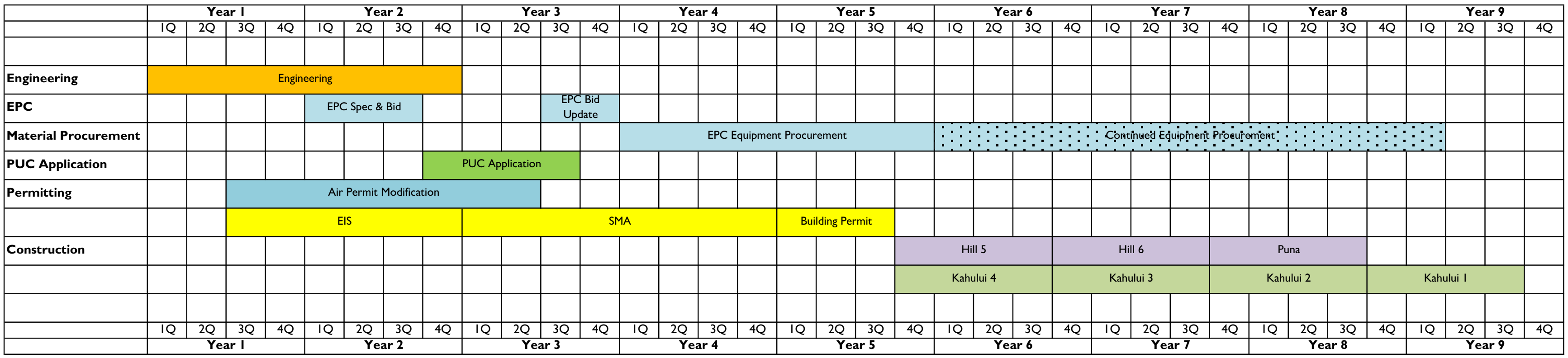
Figure 9-4. HECO Schedule for Kahe and Waiau



HELCO-MECO Schedule for Hill, Puna, and Kahului

The schedule begins first quarter 2014 (Year 1) and is projected to conclude second quarter 2022 (Year 9). The schedule assumes a lead-time for equipment of 18 months and for construction to take four months.

Figure 9-5. HELCO-MECO Schedule for Hill, Puna, and Kahului



Hawaiian Electric Fuel Switch Strategy Schedules

The following schedules depict timelines for two possible fuel switching strategies for Hawaiian Electric to comply with MATS and NAAQS requirements.

Figure 9-6. Hawaiian Electric Fuel Switch Strategy 1

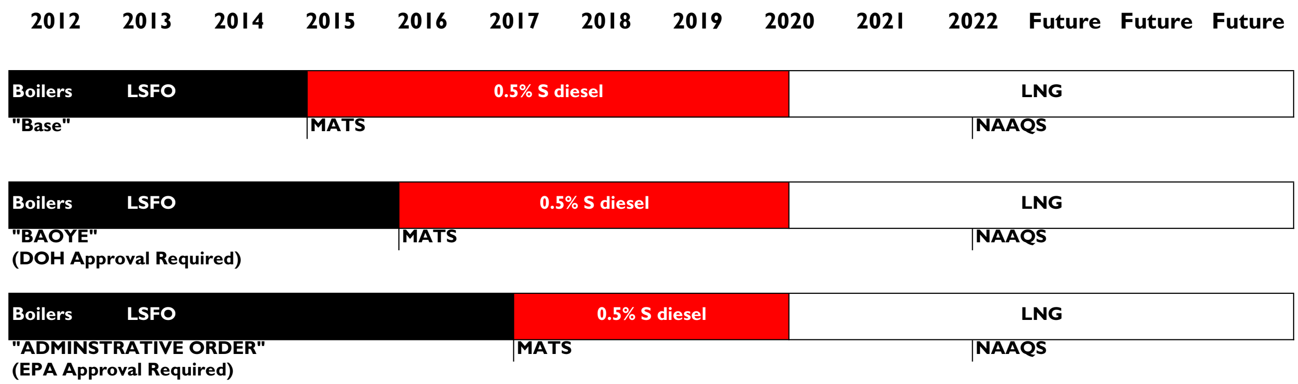
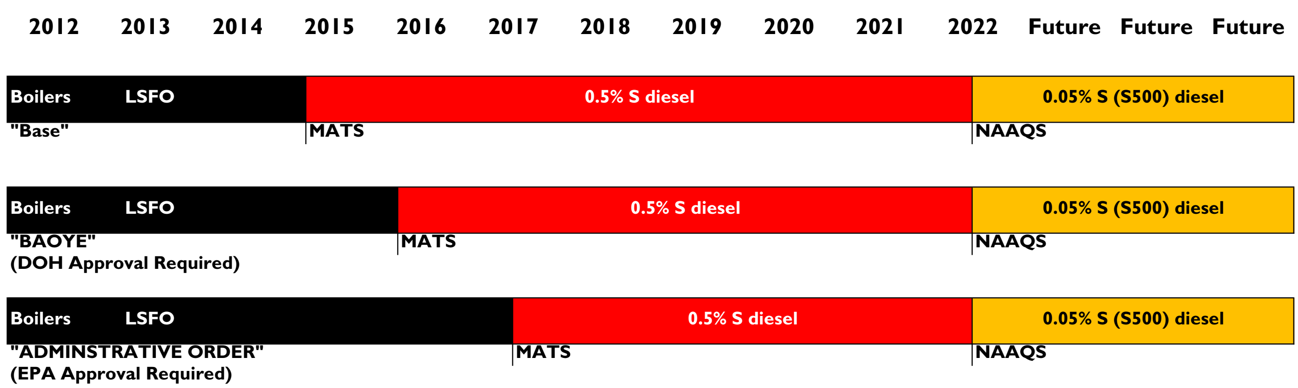


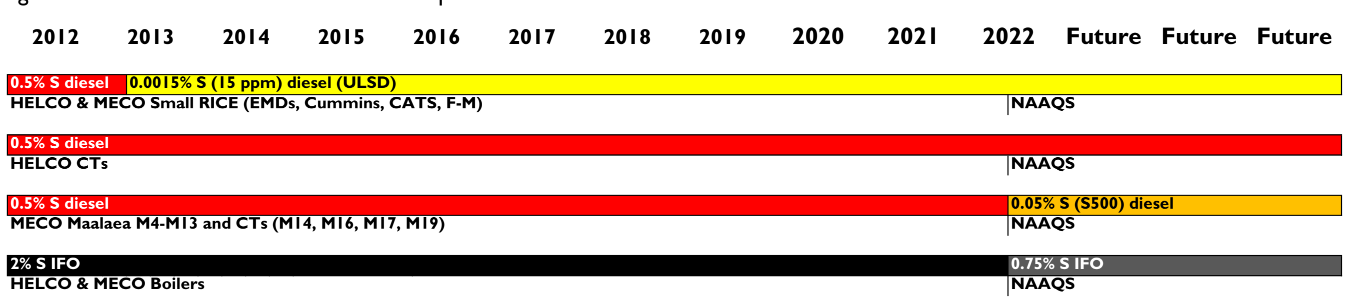
Figure 9-7. Hawaiian Electric Fuel Switch Strategy 2



HELCO & MECO Fuel Switch Strategy Schedule

This schedule depicts the timeline for how HELCO and MECO are switching fuels to comply with NAAQS requirements.

Figure 9-8. HELCO-MECO Fuel Switch Compliance Schedule



Complying with Environmental Standards

The Companies analyzed the comparative costs and benefits of various strategies to comply with the expected and possible changes in environmental regulations discussed in Environmental Compliance Alternatives (page 9-2). A description of each utility's analysis follows.

Hawaiian Electric Environmental Compliance

Hawaiian Electric's analysis focused on complying with the MATS and NAAQS regulations.

Hawaiian Electric MATS Compliance Strategy

To comply with the MATS, particulate matter emissions would need to be controlled through any one of the following three methods.

Reduce Particulate Matter. Particulate matter (PM) emitted by oil-fired boilers contains ash (non-combustible mineral matter), inorganic compounds (sulfates, salts, sediments), and carbonaceous organic compounds (from unburned carbon). An electrostatic precipitator (ESP) is a control device that traps and removes PM produced by boilers. Installation of ESPs, however, would not be able to be completed by the 2015 compliance date (see Implementation Schedules on page 9-14).

Reduce Ash and Sulfur Content in Fuel. Assuming the broadly available one-year extension until 2016 being granted, switching to 0.5% sulfur No. 2 diesel fuel in 2016 appears to be the only compliance option. Fuel additives could also reduce PM, but it would need to be tested to verify its effectiveness.

Install a PM Control Device. This strategy could also not be completed until after the 2015 deadline.

Hawaiian Electric NAAQS Compliance Strategy

The Companies analyzed several strategies to comply with the more stringent, one-hour air quality standards (NAAQS) for nitrogen dioxide (NO_2) and sulfur dioxide (SO_2).

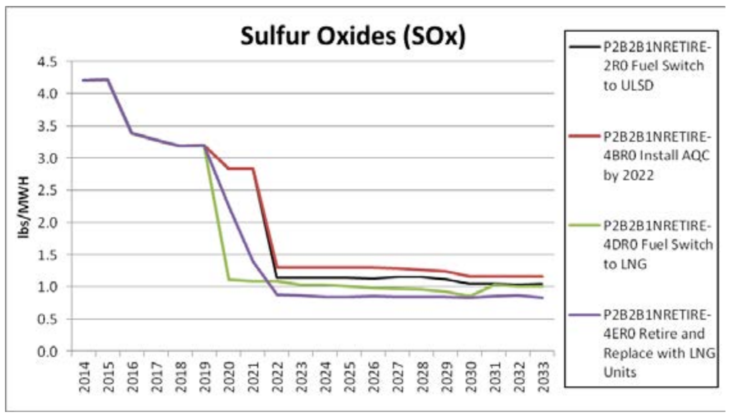
Controlling Nitrogen Oxides (NOx) Emissions. Nitric oxide (NO) and NO_2 emissions can be controlled by AQC combustion hardware improvements (such as low NOx burners and overfire air). The Companies also analyzed retiring existing units and replacing them with new generation burning LNG or, in some cases, biofuels.

Controlling Sulfur Dioxide Emissions. SO_2 can be controlled by either:

- Reducing the sulfur content in the fuel by switching to lower sulfur content fuels (such as ultra low sulfur diesel, biofuels, or liquefied natural gas (LNG)).
- Installing Air Quality Control (AQC) equipment (such as scrubbers) coupled with ESPs to remove sulfur from exhaust gases.

Figure 9-9 illustrates SO_2 emission reductions achieved by the strategies in all scenarios to comply with NAAQS regulations.

Figure 9-9. HECO Typical Illustration of Sulfur Dioxide Emission Reductions Achieved by Strategies



Hawaiian Electric Resource Plans

Hawaiian Electric developed several resource plans by modeling these compliance strategies in each of the four scenarios. Stuck in the Middle (Table 9-9) depicts two retire-and-replace plans. The plan P2B2b1NRetire-4Er0 shows a more aggressive retirement schedule while the plan P2B2b1NRetire-4Er1 spreads out the retirements in a longer period.

Table 9-7 through Table 9-12 summarizes all of these resource plans.

Table 9-7. HECO Blazing a Bold Frontier Environmental Compliance Resource Plans (1 of 2)

Name	**Self Generation**		**P1B2a1XRetire-2r2**	**P1B2a1XRetire-2r2 AQC**	**P1B2a1xRetire-2r6**
Plan	Annual	Cumulative	Fuel Switch to ULSD in 2022	Install Air Quality Controls in 2022	Fuel Switch to Biofuels in 2020
Notes			Wind30, offshore wind, PV5, & Wave15, CT91 available; Cycle Kahe 1–4 in 2020, >20% curtail	Wind30, offshore wind, PV5, & Wave15, CT91 available; Cycle Kahe 1–4 in 2020, >20% curtail	Fuel switch applies to all Waiau 5–10 and Kahe 1–6, Cycle Kahe 1–2 to reduce dumped energy
Resources Available			ICE (17 MW); Biodiesel (PS01): n/a 100 MW SCCT; Biodiesel (PS07): 2020 30 MW Onshore Wind Cl 3 (PW01): 2018 10 MW Onshore Wind Cl 5 (PW03): n/a 10 MW Onshore Wind Cl 7 (PW04): n/a 100 MW Offshore Wind (PW05): n/a 5 MW of 1 MW Tracking PV (PP03): 2015 50 MW Parbolic Trough PV (PP04): n/a 9.6 MW OTEC (POT1): n/a 15 MW Ocean Wave 5 MW (PV02): 2020	ICE (17 MW); Biodiesel (PS01): n/a 100 MW SCCT; Biodiesel (PS07): 2020 30 MW Onshore Wind Cl 3 (PW01): 2018 10 MW Onshore Wind Cl 5 (PW03): n/a 10 MW Onshore Wind Cl 7 (PW04): n/a 100 MW Offshore Wind (PW05): n/a 5 MW of 1 MW Tracking PV (PP03): 2015 50 MW Parbolic Trough PV (PP04): n/a 9.6 MW OTEC (POT1): n/a 15 MW Ocean Wave 5 MW (PV02): 2020	ICE (17 MW); Biodiesel (PS01): n/a 100 MW SCCT; Biodiesel (PS07): n/a 30 MW Onshore Wind Cl 3 (PW01): 2018 10 MW Onshore Wind Cl 5 (PW03): n/a 10 MW Onshore Wind Cl 7 (PW04): n/a 100 MW Offshore Wind (PW05): n/a 5 MW of 1 MW Tracking PV (PP03): 2020 50 MW Parbolic Trough PV (PP04): n/a 9.6 MW OTEC (POT1): n/a 15 MW Ocean Wave 5 MW (PV02): n/a
2014	35MW	75 MW	Continue CIDLC, CIDP, RDLCWH, RDLCAC	Continue CIDLC, CIDP, RDLCWH, RDLCAC	Continue CIDLC, CIDP, RDLCWH, RDLCAC
			75%+25%+10% PBFA DSM	75%+25%+10% PBFA DSM	75%+25%+10% PBFA DSM
2015	36MW	111MW	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)	
2016	43MW	154MW	Fuel switch to diesel (Honolulu 8/9, Waiau 5–10/Kahe 1–6)	Fuel switch to diesel (Honolulu 8/9, Waiau 5–10/Kahe 1–6)	Fuel switch to diesel (Honolulu 8/9, Waiau 5–10/Kahe 1–6)
			Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)	
2017	36MW	189MW	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)	
			Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW) or Honolulu 8/9	Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW) or Honolulu 8/9	Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW) or Honolulu 8/9
2018	36MW	225MW	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)	
			Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)	

Name	Self Generation		P1B2a1XRetire-2r2	P1B2a1XRetire-2r2 AQC	P1B2a1xRetire-2r6
2019	35MW	260MW	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)	
			Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)	
			Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW) or Deactivate Waiau 3/4	Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW) or Deactivate Waiau 3/4	Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW) or Deactivate Waiau 3/4
2020	35MW	295MW	Fuel switch to ULSD (Waiau 5–10/Kahe 1–6)		Fuel switch to biofuel (Waiau 5–10/Kahe 1–6)
			Cycle Kahe 1–4	Cycle Kahe 1–4	
			Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)	
			Add 180 MW wind (PW01x6)	Add 180 MW wind (PW01x6)	
2021	35MW	331MW	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)	
2022	28MW	363MW		AQC Waiau 5–8 & Kahe 1–6	
			Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)	
2023	28MW	391MW			Cycle Kahe 1 & 2
2024	25MW	416MW			
2025	21MW	437MW			
2026	18MW	456MW			
2027	16MW	472MW			
2028	15MW	486MW	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)	
2029	14MW	500MW	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)	
2030	13MW	513MW	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)	
			Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)	
2031	12MW	525MW			
2032	12MW	538MW	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)	
			Add 100 MW wind (PW05x1)	Add 100 MW wind (PW05x1)	
2033	12MW	549MW	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)	
			Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)	
			Add 100 MW wind (PW05x1)	Add 100 MW wind (PW05x1)	
Strategist Planning Period Total Cost			29,078,658	28,827,210	26,404,916
Strategist Study Period Total Cost			38,170,088	37,763,932	32,020,054
Planning Period Total Cost			30,857,503	32,590,956	29,082,294
Study Period Total Cost			40,847,465	41,527,673	34,697,431
Planning Rank			5	6	1
Study Rank			5	6	1

Table 9-8. HECO Blazing a Bold Frontier Environmental Compliance Resource Plans (2 of 2)

Name	**Self Generation**		**P1B2a1xRetire-4Dr6**	**P1B2a1xRetire-4Er0**	**P1B2a1xRetire-4Fr0**
Plan			Fuel Switch to LNG in 2020	Deactivate Existing Replace with Conventional LNG Units	Deactivate Existing Replace with Conventional Biofueled Units
Notes			Fuel switch applies to all Waiau 5–8 and Kahe 1–6, Cycle Kahe 1–4 to reduce dumped energy	All units are deactivated by 2022	All units are deactivated by 2022
Resources Available	Annual	Cumulative	ICE (17 MW); Biodiesel (PS01): n/a 100 MW SCCT; Biodiesel (PS07): n/a 30 MW Onshore Wind Cl 3 (PW01): 2018 10 MW Onshore Wind Cl 5 (PW03): n/a 10 MW Onshore Wind Cl 7 (PW04): n/a 100 MW Offshore Wind (PW05): n/a 5 MW of 1 MW Tracking PV (PP03): 2020 50 MW Parbolic Trough PV (PP04): n/a 9.6 MW OTEC (POT1): n/a 15 MW Ocean Wave 5 MW (PV02): n/a	95 MW SCCT LMS 100; LNG (PS07): 2018 42 MW LM6000 SCCT LNG (PC08): n/a 59 MW 1on1 LM6000 CC; LNG (PS12): 2020 25MW Banagrass (PA01): n/a 400 kW Nat Gas Fuel Cell (FC40): n/a 30 MW Onshore Wind Cl 3 (PW01): 2018 10 MW Onshore Wind Cl 5 (PW03): n/a 5 MW of 1 MW Tracking PV (PP03): 2018	95 MW SCCT LMS 100; Biodiesel (PS07): 2018 42 MW LM6000 SCCT Biodiesel (PC08): n/a 59 MW 1on1 LM6000 CC; LNG (PS12): 2020 25MW Banagrass (PA01): n/a 400 kW Nat Gas Fuel Cell (FC40): n/a 30 MW Onshore Wind Cl 3 (PW01): 2018 10 MW Onshore Wind Cl 5 (PW03): n/a 5 MW of 1 MW Tracking PV (PP03): 2018
2014	35MW	75 MW	Continue CIDLC, CIDP, RDLCWH, RDLCAC	Continue CIDLC, CIDP, RDLCWH, RDLCAC	Continue CIDLC, CIDP, RDLCWH, RDLCAC
			75%+25%+10% PBFA DSM	75%+25%+10% PBFA DSM	75%+25%+10% PBFA DSM
2015	36MW	111MW			
2016	43MW	154MW	Fuel switch to diesel (Honolulu 8/9, Waiau 5–10/Kahe 1–6)	Fuel switch to diesel (Honolulu 8/9, Waiau 5–10/Kahe 1–6)	Fuel switch to diesel (Honolulu 8/9, Waiau 5–10/Kahe 1–6)
2017	36MW	189MW	Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW) or Honolulu 8/9	Retire Waiau 3 (–46 MW) Retire Waiau 4 (–46 MW) or Honolulu 8/9	Retire Waiau 3 (–46 MW) Retire Waiau 4 (–46 MW) or Honolulu 8/9
2018	36MW	225MW	Add 60 MW wind (PW01x2)	Add 20 MW SAT PV (PP03x4)	Add 20 MW SAT PV (PP03x4)
2019	35MW	260MW	Add 60 MW wind (PW01x2)	Add 20 MW SAT PV (PP03x4)	
			Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW) or Deactivate Waiau 3/4	Retire Honolulu 8 (–53 MW) Retire Honolulu 9 (–54 MW) or Retire Waiau 3/4	Retire Honolulu 8 (–53 MW) Retire Honolulu 9 (–54 MW) or Waiau 3/4

Name	Self Generation		P1B2a1xRetire-4Dr6	P1B2a1xRetire-4Er0	P1B2a1xRetire-4Fr0
2020	35MW	295MW	Fuel switch to LNG (Waiau 5–10, Kahe 1–6)		
			Add 150 MW wind (PW01x5)	Add 20 MW SAT PV (PP03x4)	Add 150 MW wind (PW01x5)
			Add 20 MW SAT PV (PP03x4)	Add 210 MW wind (PW01x7)	
				Retire Waiau 5 (–55MW) Retire Waiau 6 (–56MW) Retire Waiau 7 (–88MW) Retire Waiau 8 (–88MW) Retire Kahe 1 (–88MW) Retire Kahe 2 (–86MW) Retire Kahe 3 (–88MW) Retire Kahe4 (–89MW)	Retire Waiau 5 (–55MW) Retire Waiau 6 (–56MW) Retire Waiau 7 (–88MW) Retire Waiau 8 (–88MW) Retire Kahe 1 (–88MW) Retire Kahe 2 (–86MW) Retire Kahe 3 (–88MW) Retire Kahe4 (–89MW)
				Add 182MW SCCT (PS07x2); LNG	Add 182MW SCCT (PS07x2); biofuel
				Add 59MW CC (PC08x1); LNG	Add 59MW CC (PC08x1); biofuel
2021	35MW	331MW	Add 20 MW SAT PV (PP03x4)	Add 90 MW wind (PW01x3)	Add 60 MW wind (PW01x2)
				Add 20 MW SAT PV (PP03x4)	
				Add 182MW SCCT (PS07x2); LNG	Add 182MW SCCT (PS07x2); biofuel
				Retire Kahe 5 (–135MW)	Retire Kahe 5 (–135MW)
2022	28MW	363MW	Add 20 MW SAT PV (PP03x4)	Add 20 MW SAT PV (PP03x4)	Add 60 MW wind (PW01x2)
				Add 59MW CC (PC08x1); LNG	Add 59MW CC (PC08x1); biofuel
				Add 91MW SCCT (PS07x1); LNG	Add 91MW SCCT (PS07x1); biofuel
				Retire Kahe 6 (–134MW)	Retire Kahe 6 (–134MW)
2023	28MW	391MW	Cycle Kahe 1–4	Add 59MW CC (PC08x1); LNG	Add 59MW CC (PC08x1); biofuel
				Add 20 MW SAT PV (PP03x4)	Add 30 MW wind (PW01x1)
			Add 20 MW SAT PV (PP03x4)		
2024	25MW	416MW	Add 20 MW SAT PV (PP03x4)	Add 20 MW SAT PV (PP03x4)	
2025	21MW	437MW	Add 20 MW SAT PV (PP03x4)		
2026	18MW	456MW		Add 60 MW wind (PW01x2)	
2027	16MW	472MW		Add 60 MW wind (PW01x2)	
2028	15MW	486MW			
2029	14MW	500MW	Add 20 MW SAT PV (PP03x4)		
2030	13MW	513MW	Cycle Kahe 6 & Waiau 7		
			Add 180 MW wind (PW01x6)		
			Add 60 MW SAT PV (PP03x12)		
2031	12MW	525MW			
2032	12MW	538MW			
2033	12MW	549MW			
Strategist Planning			27,601,824	27,185,884	26,620,508

Name	Self Generation		P1B2a1xRetire-4Dr6	P1B2a1xRetire-4Er0	P1B2a1xRetire-4Fr0
Period Total Cost					
Strategist Study Period Total Cost			34,621,540	33,589,848	32,645,724
Planning Period Total Cost			30,571,308	29,759,536	29,111,265
Study Period Total Cost			37,591,025	36,163,501	35,136,481
Planning Rank			4	3	2
Study Rank			4	3	2

Table 9-9. HECO Stuck in the Middle Environmental Compliance Resource Plans (1 of 2)

Name	Self Generation		P2B2b1NRetire-2r0	P2B2b1NRetire-4Br0	P2B2b1NRetire-4Dr0
Plan			Fuel Switch to ULSD in 2022	Install Air Quality Controls in 2022	Fuel Switch to LNG in 2020
Notes			Fuel switch applies to all Waiau 5–8 and Kahe 1–6	Install AQC on Waiau 5–8 and Kahe 1–6	Fuel switch applies to all Waiau 5–8 and Kahe 1–6
Resources Available	Annual	Cumulative	ICE (17 MW); Biodiesel (PS01): n/a 100 MW SCCT; Biodiesel (PS07): n/a 42 MW LM6000 SCCT LNG (PC08): n/a 59 MW 1on1 LM6000 CC; LNG (PS12): 2020 25MW Banagrass (PA01): 2027 30 MW Onshore Wind Cl 3 (PW01): 2016 10 MW Onshore Wind Cl 5 (PW03): n/a 10 MW Onshore Wind Cl 7 (PW04): n/a 100 MW Offshore Wind (PW05): n/a 5 MW of 1 MW Tracking PV (PP03): 2015 50 MW Parbolic Trough PV (PP04): n/a 9.6 MW OTEC (POT1): n/a 15 MW Ocean Wave 5 MW (PV02): 2020	ICE (17 MW); Biodiesel (PS01): n/a; 100 MW SCCT; Biodiesel (PS07): n/a; 42 MW LM6000 SCCT LNG (PC08): n/a; 59 MW 1on1 LM6000 CC; LNG (PS12): 2020; 25MW Banagrass (PA01): 2027; 30 MW Onshore Wind Cl 3 (PW01): 2016; 10 MW Onshore Wind Cl 5 (PW03): n/a; 10 MW Onshore Wind Cl 7 (PW04): n/a; 100 MW Offshore Wind (PW05): n/a; 5 MW of 1 MW Tracking PV (PP03): 2016; 50 MW Parbolic Trough PV (PP04): n/a; 9.6 MW OTEC (POT1): n/a; 15 MW Ocean Wave 5 MW (PV02): 2020	ICE (17 MW); Biodiesel (PS01): n/a; 100 MW SCCT; Biodiesel (PS07): n/a; 42 MW LM6000 SCCT LNG (PC08): n/a; 59 MW 1on1 LM6000 CC; LNG (PS12): 2020; 25MW Banagrass (PA01): 2027; 30 MW Onshore Wind Cl 3 (PW01): 2016; 10 MW Onshore Wind Cl 5 (PW03): n/a; 10 MW Onshore Wind Cl 7 (PW04): n/a; 100 MW Offshore Wind (PW05): n/a; 5 MW of 1 MW Tracking PV (PP03): 2016; 50 MW Parbolic Trough PV (PP04): n/a; 9.6 MW OTEC (POT1): n/a; 15 MW Ocean Wave 5 MW (PV02): 2020
2014	35MW	75 MW	Expanded CIDLC, CIDP, RDLCWH, RDLCAC	Expanded CIDLC, CIDP, RDLCWH, RDLCAC	Expanded CIDLC, CIDP, RDLCWH, RDLCAC
			75% PBFA DSM	75% PBFA DSM	75% PBFA DSM
2015	36MW	111MW			
2016	43MW	154MW	Fuel switch to diesel (Honolulu 8/9, Waiau 5–10/Kahe 1–6)	Fuel switch to diesel (Honolulu 8/9, Waiau 5–10/Kahe 1–6)	Fuel switch to diesel (Honolulu 8/9, Waiau 5–10/Kahe 1–6)
			Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)
			Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)
2017	36MW	189MW	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)
			Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW) or Honolulu 8/9	Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW) or Honolulu 8/9	Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW) or Honolulu 8/9
2018	36MW	225MW	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)
2019	35MW	260MW	Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW) or Deactivate Waiau 3/4	Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW) or Deactivate Waiau 3/4	Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW) or Deactivate Waiau 3/4
2020	35MW	295MW			Fuel switch to LNG (Waiau 5–8,

Name	Self Generation		P2B2b1NRetire-2r0	P2B2b1NRetire-4Br0	P2B2b1NRetire-4Dr0
					Kahe 1–6)
			Add 59MW CC (PC08x1); biofuel	Add 59MW CC (PC08x1); biofuel	Add 59MW CC (PC08x1); biofuel
			Add 200 MW Lanai Wind	Add 200 MW Lanai Wind	Add 200 MW Lanai Wind
2021	35MW	331MW			
2022	28MW	363MW	Fuel switch to ULSD (Waiau 5–8, Kahe 1–6)	AQC Waiau 5–8 & Kahe 1–6	
2023	28MW	391MW			
2024	25MW	416MW			
2025	21MW	437MW			
2026	18MW	456MW			
2027	16MW	472MW	Add 25MW (PA01x1); biomass	Add 25MW (PA01x1); biomass	Add 25MW (PA01x1); biomass
2028	15MW	486MW	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)
2029	14MW	500MW	Add 30 MW wind (PW01x1)	Add 30 MW wind (PW01x1)	Add 30 MW wind (PW01x1)
			Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)
2030	13MW	513MW	Add 150 MW wind (PW01x5)	Add 150 MW wind (PW01x5)	Add 150 MW wind (PW01x5)
			Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)
2031	12MW	525MW			
2032	12MW	538MW			
2033	12MW	549MW			
Strategist Planning Period Total Cost			22,234,112	22,019,958	19,836,616
Strategist Study Period Total Cost			32,899,972	32,510,080	28,042,346
Planning Period Total Cost			24,911,485	25,756,081	22,778,486
Study Period Total Cost			35,577,349	36,246,205	30,984,215
Planning Rank			2	3	1
Study Rank			2	3	1

Table 9-10. HECO Stuck in the Middle Environmental Compliance Resource Plans (2 of 2)

Name	Self Generation		P2B2b1NRetire-4Er0	P2B2b1NRetire-4Er1
Plan			Deactivate Existing Replace with Conventional LNG Units	Deactivate Existing Replace with Conventional LNG Units
Notes			All units are deactivated by 2022	All units are deactivated by 2022
Resources Available	Annual	Cumulative	ICE (17 MW); Biodiesel (PS01): 2022 95 MW SCCT LMS 100; LNG (PS07): 2020 42 MW LM6000 SCCT; LNG (PC08): n/a 59 MW 1on1 LM6000 CC; LNG (PS12): 2020 25 MW Banagrass (PA01): n/a 400 kW Nat Gas Fuel Cell (FC40): n/a 30 MW Onshore Wind Cl 3 (PW01): 2016 10 MW Onshore Wind Cl 5 (PW03): n/a 5 MW of 1 MW Tracking PV (PP03): 2016	ICE (17 MW); Biodiesel (PS01): 2022 95 MW SCCT LMS 100; LNG (PS07): 2020 42 MW LM6000 SCCT; LNG (PC08): n/a 59 MW 1on1 LM6000 CC; LNG (PS12): 2020 25 MW Banagrass (PA01): n/a 400 kW Nat Gas Fuel Cell (FC40): n/a 30 MW Onshore Wind Cl 3 (PW01): 2016 10 MW Onshore Wind Cl 5 (PW03): n/a 5 MW of 1 MW Tracking PV (PP03): 2016
2014	35MW	75 MW	Expanded CIDLC, CIDP, RDLCWH, RDLCAC	Expanded CIDLC, CIDP, RDLCWH, RDLCAC
			75% PBFA DSM	75% PBFA DSM
				Retire Honolulu 8 (–53 MW) Retire Honolulu 9 (–54 MW)
2015	36MW	111MW		
2016	43MW	154MW	Fuel switch to diesel (Honolulu 8/9, Waiau 5–10/Kahe 1–6)	Fuel switch to diesel (Honolulu 8/9, Waiau 5–10/Kahe 1–6)
			Add 20 MW PV (PP03x4)	
			Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)
2017	36MW	189MW	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)
			Retire Waiau 3 (–46 MW) Retire Waiau 4 (–46 MW) or Honolulu 8/9	Retire Waiau 3 (–46 MW) Retire Waiau 4 (–46 MW)
2018	36MW	225MW	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)
				Add 68MW ICE (PS01x4); biofuel
2019	35MW	260MW	Retire Honolulu 8 (–53 MW) Retire Honolulu 9 (–54 MW) or Waiau 3/4	
2020	35MW	295MW		Add 60 MW wind (PW01x2)
			Add 91MW CT (PS07x1); LNG	
			Add 354MW CC (PC08x6); LNG	Add 285MW SCCT (PS08x3); LNG
			Add 200 MW Lanai Wind	Add 200 MW Lanai Wind
			Retire Waiau 5 (–55MW) Retire Waiau 6 (–56MW) Retire Waiau 7 (–88MW) Retire Waiau 8 (–88MW) Retire Kahe 1 (–88MW) Retire Kahe 2 (–86MW) Retire Kahe 3 (–88MW) Retire Kahe 4 (–89MW)	Retire Waiau 5 (–55MW) Retire Waiau 6 (–56MW)

Name	Self Generation		P2B2b1NRetire-4Er0	P2B2b1NRetire-4Er1
2021	35MW	331MW	Add 91MW CT (PS07x1); LNG	Add 90 MW wind (PW01x3)
			Add 118 MW CC (PC08x2); LNG	Add 95MW SCCT (PS08x1); LNG
			Retire Kahe 5 (–135MW)	Retire Waiau 7 (–88MW) Retire Waiau 8 (–88MW)
2022	28MW	363MW	Add 68MW ICE (PS01x4); biofuel	Add 190MW SCCT (PS08x2)-LNG
			Add 91MW CT (PS07x1); LNG	Retire Kahe 1 (–88MW) Retire Kahe 2 (–86MW)
			Retire Kahe 6 (–134MW)	Retire Kahe 6 (–134MW)
2023	28MW	391MW		
2024	25MW	416MW		
2025	21MW	437MW		
2026	18MW	456MW		
2027	16MW	472MW	Add 25MW (PA01x1); biomass	
2028	15MW	486MW	Add 20 MW PV (PP03x4)	
2029	14MW	500MW	Add 30 MW wind (PW01x1)	
			Add 20 MW PV (PP03x4)	
2030	13MW	513MW	Add 150 MW wind (PW01x5)	
			Add 20 MW PV (PP03x4)	
2031	12MW	525MW		
2032	12MW	538MW		
2033	12MW	549MW		
Strategist Planning Period Total Cost			21,965,590	22,672,492
Strategist Study Period Total Cost			30,506,690	31,544,914
Planning Period Total Cost			24,539,245	25,268,402
Study Period Total Cost			33,080,343	34,140,824
Planning Rank			1	2
Study Rank			1	2

Table 9-11. HECO No Burning Desire Environmental Compliance Resource Plans

Name	**P3B2b1NRetire-2r0**	**P3B2b1NRetire-4Br0**	**P3B2b1NRetire-4Dr0**	**P3B2b1NRetire-4Er2**
Plan	Fuel Switch to ULSD in 2022	Install Air Quality Controls in 2022	Fuel Switch to LNG in 2020	Deactivate Existing Replace with Conventional LNG Units
Notes	Fuel switch applies to all Waiau 5–8 and Kahe 1–6	Install AQC on Waiau 5–8 and Kahe 1–6	Fuel switch applies to all Waiau 5–8 and Kahe 1–6	All units are deactivated by 2022
Resources Available	ICE (17 MW); Biodiesel (PS01): 2016 100 MW SCCT; Biodiesel (PS07): 2016 42 MW LM6000 SCCT LNG (PC08): 2016 59 MW 1on1 LM6000 CC; LNG (PS12): 2020 25MW Banagrass (PA01): 2027 30 MW Onshore wind Cl 3 (PW01): 2020 10 MW Onshore wind Cl 5 (PW03): n/a 10 MW Onshore wind Cl 7 (PW04): n/a 100 MW Offshore wind (PW05): n/a 5 MW of 1 MW Tracking PV (PP03): 2015 50 MW Parbolic Trough PV (PP04): n/a 9.6 MW OTEC (POT1): n/a 15 MW Ocean Wave 5 MW (PV02): n/a	ICE (17 MW); Biodiesel (PS01): 2016 100 MW SCCT; Biodiesel (PS07): 2016 42 MW LM6000 SCCT LNG (PC08): n/a 59 MW 1on1 LM6000 CC; LNG (PS12): 2020 25MW Banagrass (PA01): 2027 30 MW Onshore wind Cl 3 (PW01): 2020 10 MW Onshore wind Cl 5 (PW03): n/a 10 MW Onshore wind Cl 7 (PW04): n/a 100 MW Offshore wind (PW05): n/a 5 MW of 1 MW Tracking PV (PP03): 2015 50 MW Parbolic Trough PV (PP04): n/a 9.6 MW OTEC (POT1): n/a 15 MW Ocean Wave 5 MW (PV02): n/a	ICE (17 MW); Biodiesel (PS01): n/a 100 MW SCCT; Biodiesel (PS07): n/a 42 MW LM6000 SCCT LNG (PC08): n/a 59 MW 1on1 LM6000 CC; LNG (PS12): 2020 25MW Banagrass (PA01): 2027 30 MW Onshore wind Cl 3 (PW01): 2020 10 MW Onshore wind Cl 5 (PW03): n/a 10 MW Onshore wind Cl 7 (PW04): n/a 100 MW Offshore wind (PW05): n/a 5 MW of 1 MW Tracking PV (PP03): n/a 50 MW Parbolic Trough PV (PP04): n/a 9.6 MW OTEC (POT1): n/a 15 MW Ocean Wave 5 MW (PV02): 2020	ICE (17 MW); Biodiesel (PS01): n/a 95 MW SCCT LMS 100; LNG (PS07): 2016 42 MW LM6000 SCCT LNG (PC08): n/a 59 MW 1on1 LM6000 CC; LNG (PS12): 2019 25MW Banagrass (PA01): n/a 400 kW Nat Gas Fuel Cell (FC40): n/a 30 MW Onshore wind Cl 3 (PW01): 2020 10 MW Onshore wind Cl 5 (PW03): n/a 5 MW of 1 MW Tracking PV (PP03): n/a
2014	Expanded CIDLC, CIDP, RDLCWH, RDLCAC	Expanded CIDLC, CIDP, RDLCWH, RDLCAC	Expanded CIDLC, CIDP, RDLCWH, RDLCAC	Expanded CIDLC, CIDP, RDLCWH, RDLCAC
	75% PBFA DSM	75% PBFA DSM	75% PBFA DSM	75% PBFA DSM
2015				
2016	Add 91MW SCCT (PS07x1); biofuel	Add 91MW SCCT (PS07x1); biofuel	Add 91MW SCCT (PS07x1); biofuel	Add 95MW SCCT (PS08x1); LNG
	Fuel switch to diesel (Honolulu 8/9,Waiau 5–10/Kahe 1–6)	Fuel switch to diesel (Honolulu 8/9,Waiau 5–10/Kahe 1–6)	Fuel switch to diesel (Honolulu 8/9,Waiau 5–10/Kahe 1–6)	Fuel switch to diesel (Honolulu 8/9,Waiau 5–10/Kahe 1–6)
2017	Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW) or Honolulu 8/9	Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW) or Honolulu 8/9	Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW) or Honolulu 8/9	Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW) or Honolulu 8/9
2018	Add 91MW SCCT (PS07x1); biofuel	Add 91MW SCCT (PS07x1); biofuel	Add 91MW SCCT (PS07x1); biofuel	Add 95MW SCCT (PS08x1); LNG

Name	P3B2b1NRetire-2r0	P3B2b1NRetire-4Br0	P3B2b1NRetire-4Dr0	P3B2b1NRetire-4Er2
2019	Add 17MW ICE (PS01x1); biofuel	Add 17MW ICE (PS01x1); biofuel	Add 17MW ICE (PS01x1); biofuel	Add 95MW SCCT (PS08x1); LNG
	Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW) or Deactivate Waiau 3/4	Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW) or Deactivate Waiau 3/4	Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW) or Deactivate Waiau 3/4	Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW) or Deactivate Waiau 3/4
2020	Add 200 MW Lanai Wind	Add 200 MW Lanai Wind	Add 200 MW Lanai Wind	Add 200 MW Lanai Wind
			Fuel switch to LNG (Waiau 5–8, Kahe 1–6)	Deactivate Waiau 5 (–55MW) Deactivate Waiau 6 (–56MW) Deactivate Waiau 7 (–88MW) Deactivate Waiau 8 (–88MW) Deactivate Kahe 1 (–88MW) Deactivate Kahe 2 (–86MW) Deactivate Kahe 3 (–88MW) Deactivate Kahe 4 (–89MW)
	Add 150 MW wind (PW01x5)	Add 150 MW wind (PW01x5)	Add 150 MW wind (PW01x5)	Add 210 MW wind (PW01x7)
	Add 182MW SCCT (PS07x2); biofuel	Add 182MW SCCT (PS07x2); biofuel	Add 182MW SCCT (PS07x2); biofuel	Add 475MW SCCT (PS08x5); LNG
2021				Add 285MW SCCT (PS08x3); LNG
	Add 120 MW wind (PW01x4)	Add 120 MW wind (PW01x4)	Add 120 MW wind (PW01x4)	Add 120 MW wind (PW01x4)
				Deactivate Kahe 5 (–135MW)
2022	Fuel switch to ULSD (Waiau 5–8, Kahe 1–6)	AQC Waiau 5–8 & Kahe 1–6		
	Add 90 MW wind (PW01x3)	Add 90 MW wind (PW01x3)	Add 90 MW wind (PW01x3)	Add 90 MW wind (PW01x3)
				Add 95MW SCCT (PS08x1); LNG
2023				Deactivate Kahe 6 (–134MW)
				Add 190MW SCCT (PS08x2); LNG
2024	Add 91MW SCCT (PS07x1); biofuel	Add 91MW SCCT (PS07x1); biofuel	Add 91MW SCCT (PS07x1); biofuel	
	Add 120 MW wind (PW01x4)	Add 120 MW wind (PW01x4)	Add 120 MW wind (PW01x4)	Add 120 MW wind (PW01x4)
2025	Add 30 MW wind (PW01x1)	Add 30 MW wind (PW01x1)	Add 30 MW wind (PW01x1)	Add 30 MW wind (PW01x1)
2026				
2027				
2028				
2029				
2030				Add 60 MW wind (PW01x2)
2031				Add 30 MW wind (PW01x1)
2032				Add 59MW STCC (PS12x1); LNG
2033	Add 34MW ICE (PS01x2); biofuel	Add 34MW ICE (PS01x2); biofuel	Add 34MW ICE (PS01x2); biofuel	

Name	P3B2b1NRetire-2r0	P3B2b1NRetire-4Br0	P3B2b1NRetire-4Dr0	P3B2b1NRetire-4Er2
Strategist PV Planning Period Total Cost	22,853,624	22,596,620	22,259,566	24,716,448
Strategist PV Study Period Total Cost	32,880,474	32,391,618	32,314,676	35,386,196
PV Planning Period Total Cost	22,935,820	23,775,391	22,633,872	23,274,023
PV Study Period Total Cost	32,962,672	33,570,391	32,688,982	35,588,355
Planning Rank	2	4	1	3
Study Rank	2	3	1	4

Table 9-12. HECO Moved by Passion Environmental Compliance Resource Plans

Name	P4B2b1NRetire-2r1 Screening	P4B2b1NRetire-4Br1	P4B2b1NRetire-4Dr1	P4B2b1NRetire-4Er1
Plan	Fuel Switch to ULSD in 2022	Install Air Quality Controls in 2022	Fuel Switch to LNG in 2020	Deactivate Existing Replace with Conventional LNG Units
Notes	Fuel switch applies to all Waiau 5–8 and Kahe 1–6	Install AQC on Waiau 5–8 and Kahe 1–6	Fuel switch applies to all Waiau 5–8 and Kahe 1–6	All units are deactivated by 2022
Resources Available	ICE (17 MW); Biodiesel (PS01): n/a 100 MW SCCT; Biodiesel (PS07): n/a 42 MW LM6000 SCCT LNG (PC08): n/a 59 MW 1on1 LM6000 CC; LNG (PS12): n/a 25MW Banagrass (PA01): 2019 30 MW Onshore wind Cl 3 (PW01): 2018 10 MW Onshore wind Cl 5 (PW03): n/a 10 MW Onshore wind Cl 7 (PW04): n/a 100 MW Offshore wind (PW05): n/a 5 MW of 1 MW Tracking PV (PP03): 2015 50 MW Parbolic Trough PV (PP04): n/a 9.6 MW OTEC (POT1): n/a 15 MW Ocean Wave 5 MW (PV02): 2020	ICE (17 MW); Biodiesel (PS01): n/a 100 MW SCCT; Biodiesel (PS07): n/a 42 MW LM6000 SCCT LNG (PC08): n/a 59 MW 1on1 LM6000 CC; LNG (PS12): n/a 25MW Banagrass (PA01): 2019 30 MW Onshore wind Cl 3 (PW01): 2018 10 MW Onshore wind Cl 5 (PW03): n/a 10 MW Onshore wind Cl 7 (PW04): n/a 100 MW Offshore wind (PW05): n/a 5 MW of 1 MW Tracking PV (PP03): 2015 50 MW Parbolic Trough PV (PP04): n/a 9.6 MW OTEC (POT1): n/a 15 MW Ocean Wave 5 MW (PV02): n/a	ICE (17 MW); Biodiesel (PS01): n/a 100 MW SCCT; Biodiesel (PS07): n/a 42 MW LM6000 SCCT LNG (PC08): n/a 59 MW 1on1 LM6000 CC; LNG (PS12): 2020 25MW Banagrass (PA01): 2027 30 MW Onshore wind Cl 3 (PW01): 2016 10 MW Onshore wind Cl 5 (PW03): n/a 10 MW Onshore wind Cl 7 (PW04): n/a 100 MW Offshore wind (PW05): n/a 5 MW of 1 MW Tracking PV (PP03): 2015 50 MW Parbolic Trough PV (PP04): n/a 9.6 MW OTEC (POT1): n/a 15 MW Ocean Wave 5 MW (PV02): n/a	ICE (17 MW); Biodiesel (PS01): n/a 95 MW SCCT LMS 100; LNG (PS07): 2020 42 MW LM6000 SCCT LNG (PC08): n/a 59 MW 1on1 LM6000 CC; LNG (PS12): 2020 25MW Banagrass (PA01): n/a 400 kW Nat Gas Fuel Cell (FC40): n/a 30 MW Onshore wind Cl 3 (PW01): 2016 10 MW Onshore wind Cl 5 (PW03): n/a 5 MW of 1 MW Tracking PV (PP03): 2016
2014	Expanded CIDLC, CIDP, RDLCWH, RDLCAC	Expanded CIDLC, CIDP, RDLCWH, RDLCAC	Expanded CIDLC, CIDP, RDLCWH, RDLCAC	Expanded CIDLC, CIDP, RDLCWH, RDLCAC
	75%+25% PBFA DSM	75%+25% PBFA DSM	75%+25% PBFA DSM	75%+25% PBFA DSM
2015	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)
2016	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)
	Fuel switch to diesel (Honolulu 8/9,Waiau 5–10/Kahe 1–6)	Fuel switch to diesel (Honolulu 8/9,Waiau 5–10/Kahe 1–6)	Fuel switch to diesel (Honolulu 8/9,Waiau 5–10/Kahe 1–6)	Fuel switch to diesel (Honolulu 8/9,Waiau 5–10/Kahe 1–6)
2017	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)
	Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW)	Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW)	Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW)	Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW)
2018	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)
	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)
2019				Add 91MW CT (PS07x1); LNG
	Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW)	Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW)	Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW)	Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW)

Name	**P4B2b1NRetire-2r1 Screening**	**P4B2b1NRetire-4Br1**	**P4B2b1NRetire-4Dr1**	**P4B2b1NRetire-4Er1**
2020				Deactivate Waiau 5 (–55MW) Deactivate Waiau 6 (–56MW) Deactivate Waiau 7 (–88MW) Deactivate Waiau 8 (–88MW) Deactivate Kahe 1 (–88MW) Deactivate Kahe 2 (–86MW) Deactivate Kahe 3 (–88MW) Deactivate Kahe 4 (–89MW)
			Fuel switch to LNG (Waiau 5–8, Kahe 1–6)	Add 91MW CT (PS07x1); LNG
				Add 236MW CC (PC08x4); LNG
	Add 200 MW Lanai Wind	Add 200 MW Lanai Wind	Add 200 MW Lanai Wind	Add 200 MW Lanai Wind
2021				Retire Kahe 5 (–135MW)
				Add 91MW CT (PS07x1); LNG
				Add 118 MW CC (PC08x2); LNG
2022	Fuel switch to ULSD (Waiau 5–8, Kahe 1–6)	AQC Waiau 5–8 & Kahe 1–6		Retire Kahe 6 (–134MW)
				Add 118 MW CC (PC08x2); LNG
2023				Add 91MW CT (PS07x1); LNG
2024				
2025				
2026				
2027				
2028	Add 30 MW wind (PW01x1)	Add 30 MW wind (PW01x1)	Add 30 MW wind (PW01x1)	Add 30 MW wind (PW01x1)
	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)
2029	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)
	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)
2030	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)
	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)
2031				
2032				
2033				
Strategist Planning Period Total Cost	23,885,070	23,686,352	21,400,236	23,187,138
Strategist Study Period Total Cost	34,006,408	33,634,624	29,089,696	30,941,318

Name	P4B2b1NRetire-2r1 Screening	P4B2b1NRetire-4Br1	P4B2b1NRetire-4Dr1	P4B2b1NRetire-4Er1
PV Planning Period Total Cost	26,617,018	27,504,668	24,424,295	25,815,367
PV Study Period Total Cost	36,738,357	37,452,937	32,113,754	33,569,543
Planning Rank	3	4	1	2
Study Rank	3	4	1	2

Hawaiian Electric Total Resource Costs

For all scenarios, the analysis shows that switching fuels results in lower total resource costs (TRC) — utility capital, operations and maintenance, and customer costs) — than installing AQC equipment. Table 9-13 shows a heat map of how the environmental strategies TRC ranks in each scenario. For Stuck in the Middle, only the lower cost retire and replace plan (P2B2b1NRetire-4Er0) results are shown. The heat map also shows that strategies involving LNG have lower costs than the other strategies across the scenarios.

Table 9-13. HECO Heat Map of Total Resource Cost of Environmental Strategies by Scenario (Thousands)

Strategies	Blazing a Bold Frontier	Stuck in the Middle	No Burning Desire	Moved by Passion
1. Fuel Switch to Ultra Low Sulfur Diesel	$40,847,465	$35,577,349	$35,557,851	$36,738,357
2. Install AQC Equipment	$41,527,673	$36,246,205	$36,155,359	$37,452,937
3. Fuel Switch to Biofuels	$34,697,431	n/a	n/a	n/a
4. Fuel Switch to LNG	$37,591,025	$30,984,215	435,284,161	$32,113,754
5. Retire and Replace with LNG	$36,163,501	$33,080,343	$37,959,849	$33,569,543
6. Retire and Replace with Biodiesel	$35,136,481	n/a	n/a	n/a

BEST					WORST

Hawaiian Electric Fuel Switching Strategies

The fuel switching strategies also lower utility capital costs, reflected in the annual revenue requirements for capital metric (Figure 9-10 through Figure 9-13) which depicts the differences in capital costs between the different environmental compliance plans.

The strategies that retire existing units and replace them with new generation have the highest capital costs, higher than installing almost $1 billion in AQC equipment.

Figure 9-10. HECO Blazing a Bold Frontier Annual Revenue Requirements of Environmental Compliance Strategies

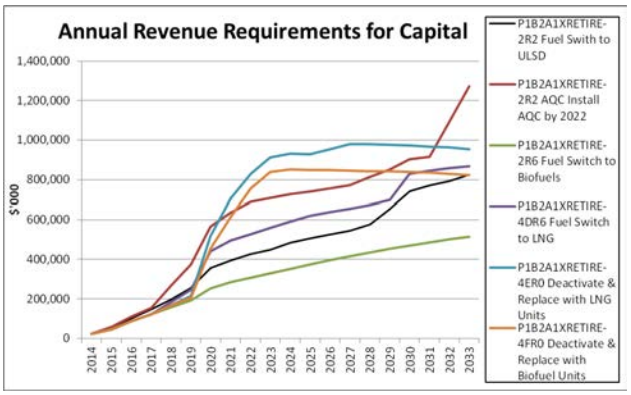


Figure 9-11. HECO Stuck in the Middle Annual Revenue Requirements of Environmental Compliance Strategies

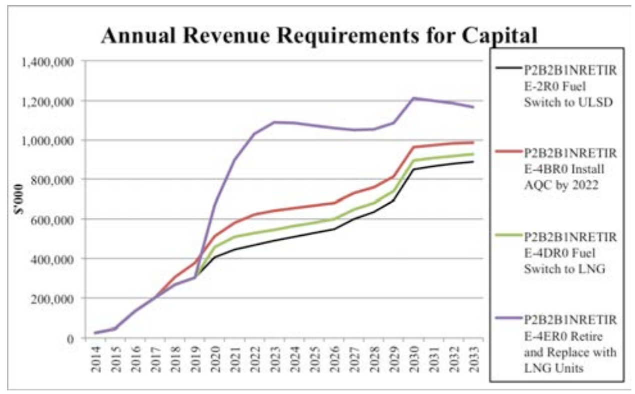


Figure 9-12. HECO No Burning Desire Annual Revenue Requirements of Environmental Compliance Strategies

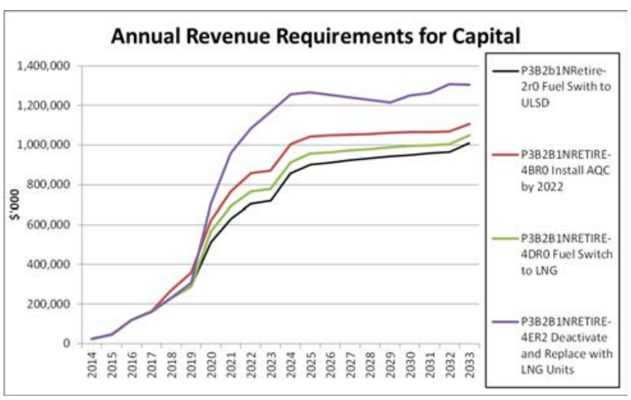
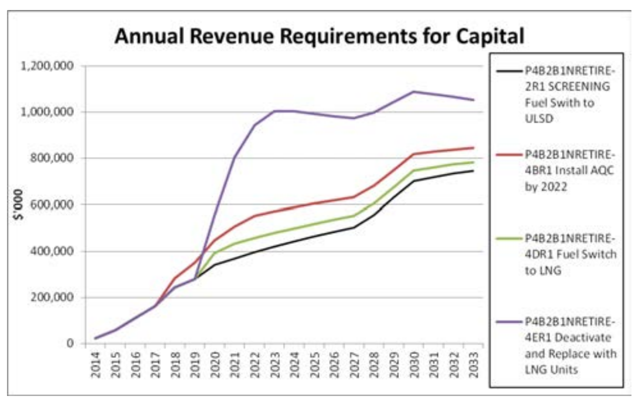


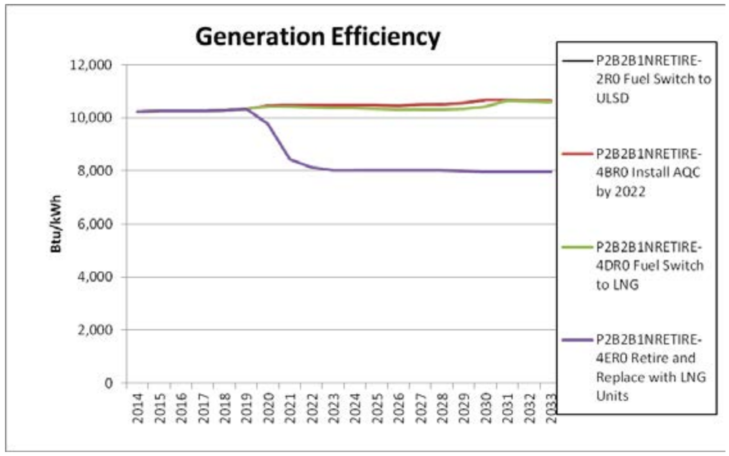
Figure 9-13. HECO Moved by Passion Annual Revenue Requirements of Environmental Compliance Strategies



Hawaiian Electric Resource Plan Costs

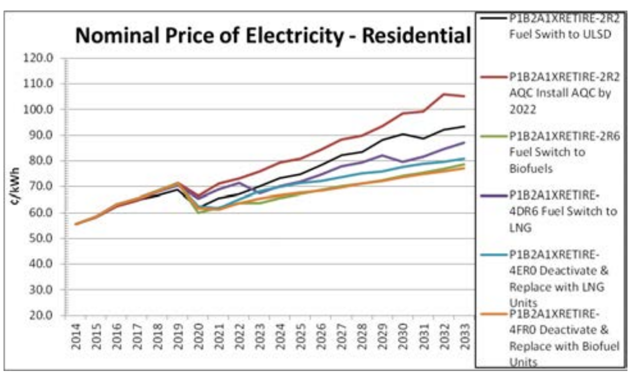
While installing new units would improve the generation efficiency of the system (Figure 9-14), these options do not have lowest TRC or lowest rates.

Figure 9-14. Illustration of Potential Generation Efficiency Improvements with New Units



Installing AQC equipment would result in the highest rates in any scenario (Figure 9-15 through Figure 9-18). Switching fuel to LNG potentially has the lowest rates of all the strategies in three out of four scenarios.

Figure 9-15. HECO Blazing a Bold Frontier Estimated Residential and Commercial Rate Impacts for Environmental Compliance Strategies



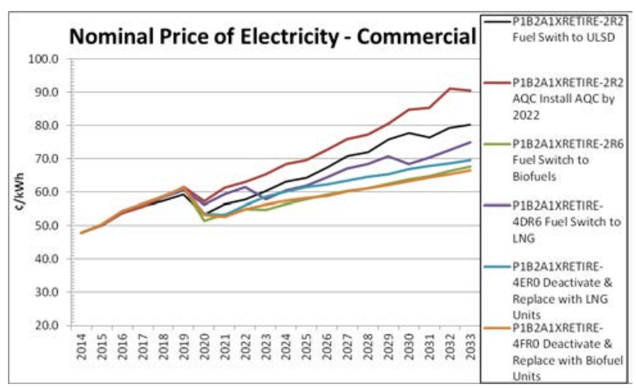


Figure 9-16. HECO Stuck in the Middle Estimated Residential and Commercial Rate Impacts for Environmental Compliance Strategies

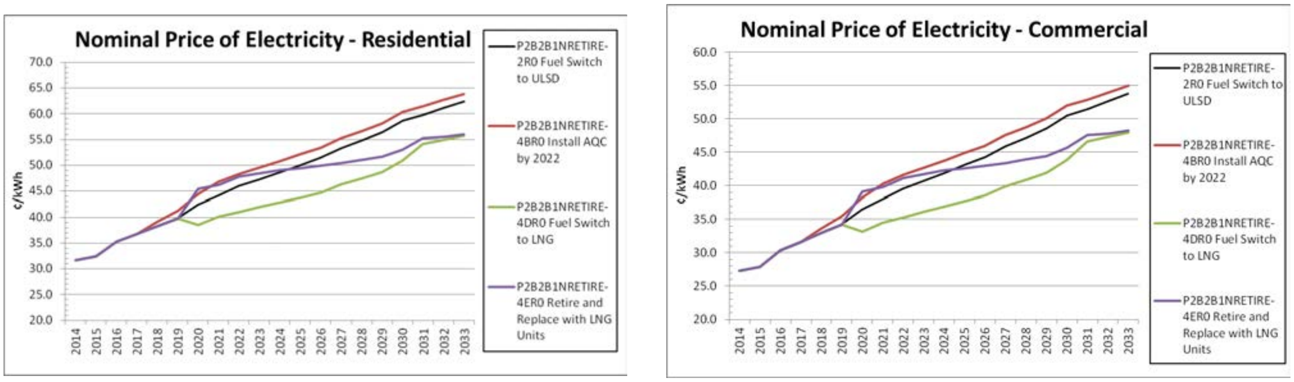


Figure 9-17. HECO No Burning Desire Estimated Residential and Commercial Rate Impacts for Environmental Compliance Strategies

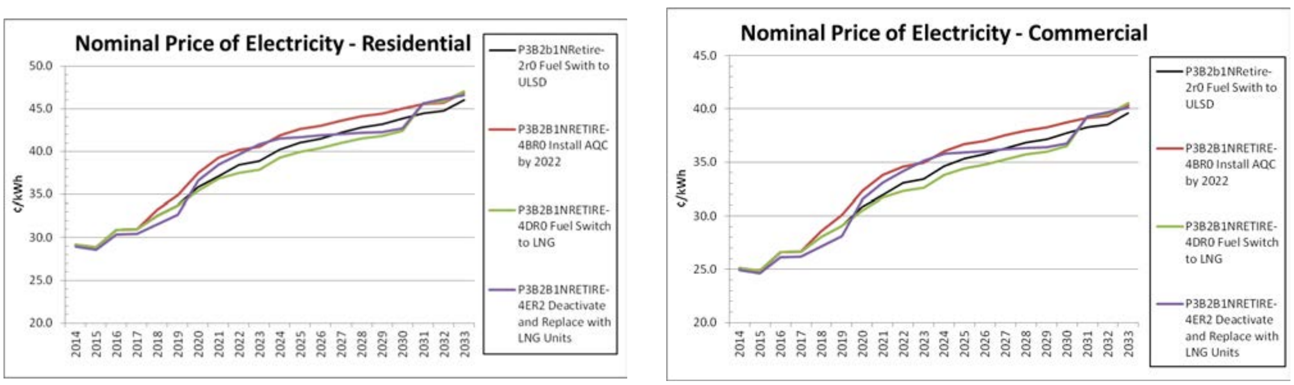
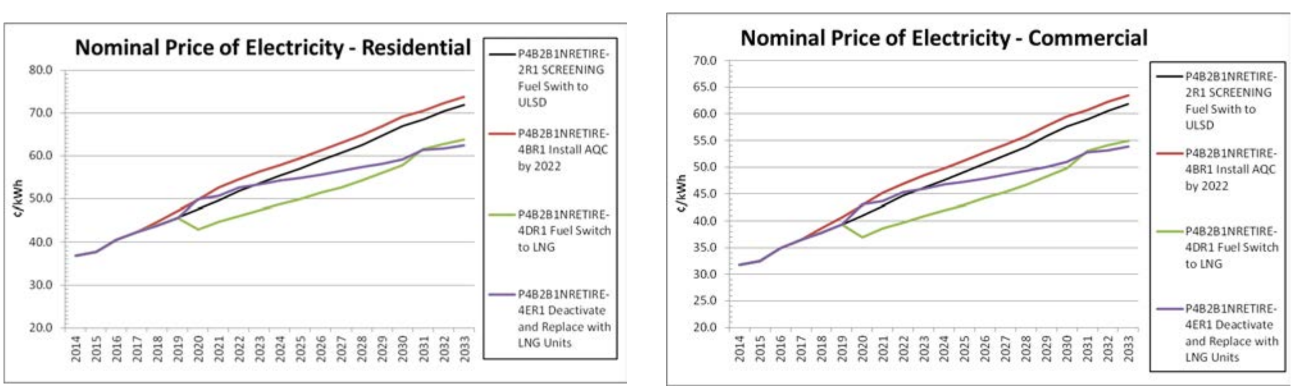


Figure 9-18. HECO Moved by Passion Estimated Residential and Commercial Rate Impacts for Environmental Compliance Strategies



For Blazing a Bold Frontier, switching existing units to biofuels and replacing existing units with new biofuel resources would result in the lowest rates because biofuel costs decline over time, reaching parity with LNG around 2025 (Table 9-14).

Table 9-14. HECO Blazing a Bold Frontier Biofuel and LNG Forecast

$/MMBtu	HECO	
Year	*Biodiesel (low)*	*LNG (high)*
2013	$43.17	n/a
2014	$37.93	n/a
2015	$35.56	$21.11
2016	$34.75	$21.53
2017	$34.22	$22.12
2018	$33.57	$22.75
2019	$32.95	$23.40
2020	$32.30	$24.09
2021	$31.49	$24.82
2022	$30.97	$25.60
2023	$30.07	$26.42
2024	$29.35	$27.27
2025	$28.63	$28.16
2026	$27.92	$29.08
2027	$27.20	$30.04
2028	$26.48	$31.04
2029	$25.76	$32.09
2030	$25.04	$33.18
2031	$24.32	$39.51
2032	$23.61	$40.71
2033	$22.89	$41.96

Hawaiian Electric Conclusion

In the near term, switching to lower sulfur fuels is the best option as opposed to making capital investments in AQC equipment. In the long term, the options involving LNG are the most attractive strategies.

HELCO Environmental Compliance

HELCO focused on complying with the NAAQS regulations by analyzing several strategies.

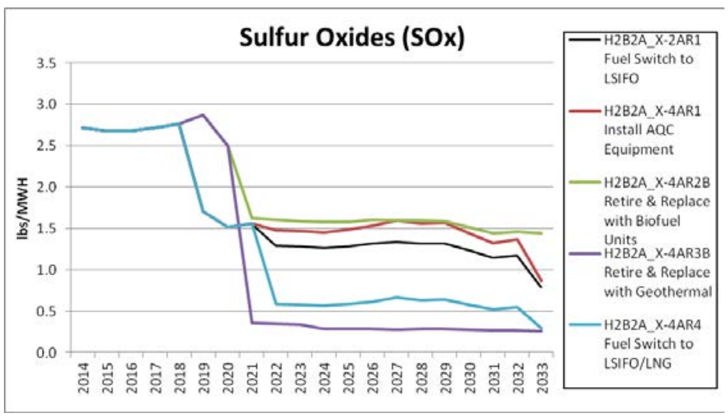
HELCO NAAQS Compliance Strategy

HELCO analyzed:

- Switching to lower sulfur fuels such as Low Sulfur Industrial Fuel Oil (LSIFO), biofuels, or LNG for Keahole CT-4, CT-5, and ST-7 combined cycle.
- Installing AQC equipment.
- Retiring existing units and replacing them with new firm geothermal or biofuel generation.

Figure 9-19 illustrates SO_2 emission reductions achieved by the strategies in all scenarios to comply with NAAQS regulations.

Figure 9-19. HELCO Typical Illustration of Sulfur Dioxide Emission Reductions Achieved by Strategies



HELCO Resource Plans

HELCO developed several resource plans by modeling these compliance strategies in each of the four scenarios. Table 9-15 through Table 9-21 summarizes all of these resource plans.

Table 9-15. HELCO Blazing a Bold Frontier Environmental Compliance Resource Plans (1 of 2)

Name	**Self Generation**		**H1B2A_X-2Ar1**	**H1B2a_X-4Ar1**	**H1B2a_X-4Ar3b**
Plan	Annual	Cumulative	Year 2022 Fuel Switch to LSIFO	Year 2022 Install Air Quality Controls	Retire Existing Replace with Geothermal
Notes			Fuel switch applies to Hill 5, Hill 6, and Puna Steam Cycle Hill 5–6, Puna Steam	Cycle Hill 5–6, Puna Steam	All Units except Keahole CC are Retired by Dec 2020 Cycle Hill 5–6, Puna Steam
2014	4MW	14MW	75%+25%+10% PBFA DSM	75%+25%+10% PBFA DSM	75%+25%+10% PBFA DSM
			Hu Honua (21.5MW)	Hu Honua (21.5MW)	Hu Honua (21.5MW)
2015	4MW	18MW	Retire Shipman 3 (–6.8 MW)	Retire Shipman 3 (–6.8 MW)	Retire Shipman 3 (–6.8 MW)
			Retire Shipman 4 (–6.7 MW)	Retire Shipman 4 (–6.7 MW)	Retire Shipman 4 (–6.7 MW)
2016	4MW	22MW			
2017	4MW	25MW	Add 10MW wind (HW04x1)	Add 10MW wind (HW04x1)	Add 10MW wind (HW04x1)
			Add 25MW geothermal (HG01x1)	Add 25MW geothermal (HG01x1)	
2018	3MW	28MW			
2019	3MW	32MW			Retire Hill 5 (–13.5 MW)
2020	3MW	35MW	Add 10MW wind (HW04x1)	Add 10MW wind (HW04x1)	Add 10MW wind (HW04x1)
					Retire Hill 6 (–20 MW) Retire Puna Steam (–15.5 MW) Retire KanoelD 11,15–17 (–9.5 MW) Retire WaimeaD 12–14 (–7.5 MW) Retire KeaholD 21–23 (–7.5 MW) Retire Kanoe CT1 (–10.25 MW) Retire Keaho CT2 (–13.80 MW) Retire Puna CT3 (–19 MW) Retire PanaewD, OuliD, PunaluD, KapuaD (–4 MW)
2021	3MW	38MW			Add 25MW geothermal (HG01x1)
					Add 50MW new geothermal (HG02x2)
2022	3MW	41MW	Fuel switch to LSIFO (Hill 5/6, Puna Steam)	AQC for Hill 5/6, Puna Steam	
2023	3MW	43MW			
2024	3MW	46MW			
2025	3MW	49MW			
2026	3MW	52MW			
2027	3MW	55MW			
2028	3MW	59MW			
2029	3MW	61MW			
2030	3MW	64MW	Add 10MW wind (HW04x1)	Add 10MW wind (HW04x1)	Add 10MW wind (HW04x1)
2031	3MW	67MW	Add 10MW wind (HW04x1)	Add 10MW wind (HW04x1)	Add 10MW wind (HW04x1)
2032	3MW	71MW			

Name	Self Generation		H1B2A_X-2Ar1	H1B2a_X-4Ar1	H1B2a_X-4Ar3b
2033	3MW	73MW			
Strategist Planning Period Total Cost			4,157,473	4,157,459	4,495,091
Strategist Study Period Total Cost			5,657,579	5,657,573	6,152,626
Planning Period Total Cost			4,803,647	4,984,793	5,142,274
Study Period Total Cost			6,303,754	6,462,721	6,799,808
Planning Rank			1	2	3
Study Rank			1	2	3

Table 9-16. HELCO Blazing a Bold Frontier Environmental Compliance Resource Plans (2 of 2)

Name	**Self Generation**		**H1B2a_X-4Ar4b**	**H1B2a_X-4Ar5b**	**H1B2A_X-4Ar6**
Plan	Annual	Cumulative	Year 2020 Fuel Switch to Biofuel	Retire Existing Replace with Conventional Biofuel Units	Year 2022 Fuel Switch to LSIFO, LNG
Notes			All Units Fuel Switch to Biofuel in Year 2020 Cycle Hill 5–6, Puna Steam	All Units except Keahole CC are Retired by Dec 2020 Cycle Hill 5–6, Puna Steam	Fuel Switch to LSIFO for Hill 5, Hill 6, and Puna Steam Fuel Switch to LNG for Keahole CC Cycle Hill 5–6, Puna Steam
2014	4MW	14MW	75%+25%+10% PBFA DSM Hu Honua (21.5MW)	75%+25%+10% PBFA DSM Hu Honua (21.5MW)	75%+25%+10% PBFA DSM Hu Honua (21.5MW)
2015	4MW	18MW	Retire Shipman 3 (–6.8 MW) Retire Shipman 4 (–6.7 MW)	Retire Shipman 3 (–6.8 MW) Retire Shipman 4 (–6.7 MW)	Retire Shipman 3 (–6.8 MW) Retire Shipman 4 (–6.7 MW)
2016	4MW	22MW			
2017	4MW	25MW	Add 10MW wind (HW04x1)	Add 10MW wind (HW04x1)	Add 10MW wind (HW04x1) Add 25MW geothermal (HG01x1)
2018	3MW	28MW			
2019	3MW	32MW		Retire Hill 5 (–13.5 MW)	
2020	3MW	35MW	Add 10MW wind (HW04x1) Convert all existing units to biofuel Hill 5–6 Puna Steam KanoeID 11,15–17 WaimeaD 12–14 KeaholD 21–23 Kanoe CT1 Keaho CT2 Puna CT3 Keaho CC1, CC2 PanaewD, OuliD, PunaluD, KapuaD	Add 10MW wind (HW04x1) Retire Hill 6 (–20 MW) Retire Puna Steam (–15.5 MW) Retire KanoeID 11,15–17 (–9.5 MW) Retire WaimeaD 12–14 (–7.5 MW) Retire KeaholD 21–23 (–7.5 MW) Retire Kanoe CT1 (–10.25 MW) Retire Keaho CT2 (–13.80 MW) Retire Puna CT3 (–19 MW) Retire PanaewD, OuliD, PunaluD, KapuaD (–4 MW)	Add 10MW wind (HW04x1)
2021	3MW	38MW		Add 63MW CT (HS05x3); biofuel	
2022	3MW	41MW			Fuel switch to LSIFO (Hill 5/6, Puna Steam) Fuel switch to LNG (Keahole CC)
2023	3MW	43MW			
2024	3MW	46MW			
2025	3MW	49MW			
2026	3MW	52MW			
2027	3MW	55MW			
2028	3MW	59MW			
2029	3MW	61MW			
2030	3MW	64MW	Add 10MW wind (HW04x1)	Add 10MW wind (HW04x1)	Add 10MW wind (HW04x1)
2031	3MW	67MW	Add 10MW wind (HW04x1)	Add 10MW wind (HW04x1)	Add 10MW wind (HW04x1)

Name	Self Generation		H1B2a_X-4Ar4b	H1B2a_X-4Ar5b	H1B2A_X-4Ar6
2032	3MW	71MW			
2033	3MW	73MW			
Strategist Planning Period Total Cost			3,920,247	4,437,591	4,046,621.50
Strategist Study Period Total Cost			5,059,908	5,900,836	5,432,833
Planning Period Total Cost			4,591,632	5,084,773	4,714,896.08
Study Period Total Cost			5,706,082	6,548,018	6,085,324
Planning Rank			1	3	2
Study Rank			1	3	2

Table 9-17. HELCO Stuck in the Middle Environmental Compliance Resource Plans (1 of 2)

Name	Self Generation		H2B2a_X-2Ar1	H2B2a_X-4Ar1	H2B2a_X-4Ar2b
Plan	Annual	Cumulative	Year 2022 Fuel Switch to LSIFO	Year 2022 Install Air Quality Controls	Retire Existing Replace with Conventional Biofuel Units
Notes			Fuel Switch applies to Hill 5, Hill 6, and Puna Steam Cycle Hill 5/6, Puna Steam	Cycle Hill 5/6, Puna Steam	All Units except Keahole CC are Retired by Dec 2020 Cycle Hill 5/6, Puna Steam
Resources Available			None	None	None
2014	2MW	8MW	75% PBFA DSM	75% PBFA DSM	75% PBFA DSM
			Hu Honua (21.5MW)	Hu Honua (21.5MW)	Hu Honua (21.5MW)
2015	2MW	10MW	Retire Shipman 3 (–6.8 MW)	Retire Shipman 3 (–6.8 MW)	Retire Shipman 3 (–6.8 MW)
			Retire Shipman 4 (–6.7 MW)	Retire Shipman 4 (–6.7 MW)	Retire Shipman 4 (–6.7 MW)
			Add 5MW PV(HP03x5)	Add 5MW PV(HP03x5)	Add 5MW PV(HP03x5)
2016	2MW	12MW			
2017	2MW	14MW	Add 10MW wind (HW04x1)	Add 10MW wind (HW04x1)	Add 10MW wind (HW04x1)
2018	2MW	15MW			
2019	2MW	17MW	Add 25MW geothermal (HG01x1)	Add 25MW geothermal (HG01x1)	Retire Hill 5 (–13.5 MW)
2020	2MW	19MW	Add 10MW wind (HW04x1)	Add 10MW wind (HW04x1)	Add 10MW wind (HW04x1)
					Retire Hill 6 (–20 MW) Retire Puna Steam (–15.5 MW) Retire KanoelD 11,15–17 (–9.5 MW) Retire WaimeaD 12–14 (–7.5 MW) Retire KeaholD 21–23 (–7.5 MW) Retire Kanoe CT1 (–10.25 MW) Retire Keaho CT2 (–13.80 MW) Retire Puna CT3 (–19 MW) Retire PanaewD, OuliD, PunaluD, KapuaD (–4 MW)

Name	Self Generation		H2B2a_X-2Ar1	H2B2a_X-4Ar1	H2B2a_X-4Ar2b
2021	2MW	21MW			Add 21MW CT (HS05x1); biofuel
					Add 63MW dual-train CC (HC05x1, HC06x1)
2022	2MW	22MW	Fuel switch to LSIFO (Hill 5/6, Puna Steam)	AQC for Hill 5/6, Puna Steam	
			Add 5MW PV(HP03x5)	Add 5MW PV(HP03x5)	Add 5MW PV(HP03x5)
2023	1MW	24MW	Add 5MW PV(HP03x5)	Add 5MW PV(HP03x5)	Add 5MW PV(HP03x5)
2024	2MW	25MW			
			Add 5MW PV(HP03x5)	Add 5MW PV(HP03x5)	Add 5MW PV(HP03x5)
2025	2MW	27MW			
2026	2MW	29MW			
2027	2MW	30MW			
2028	2MW	32MW	Add 5MW PV(HP03x5)	Add 5MW PV(HP03x5)	Add 5MW PV(HP03x5)
2029	2MW	33MW	Add 5MW PV(HP03x5)	Add 5MW PV(HP03x5)	Add 5MW PV(HP03x5)
2030	2MW	35MW	Add 10MW wind (HW04x1)	Add 10MW wind (HW04x1)	Add 10MW wind (HW04x1)
2031	2MW	37MW	Add 10MW wind (HW04x1)	Add 10MW wind (HW04x1)	Add 10MW wind (HW04x1)
2032	2MW	38MW			
2033	1MW	40MW	Add 25MW geothermal (HG02x1)	Add 25MW geothermal (HG02x1)	Add 21MW CT (HS05x1); biofuel
			Add 5MW PV(HP03x5)	Add 5MW PV(HP03x5)	Add 5MW PV(HP03x5)
Strategist Planning Period Total Cost			3,981,469	3,978,168	4,701,498
Strategist Study Period Total Cost			5,936,770	5,931,892	7,055,464
Planning Period Total Cost			3,994,908	4,156,663	4,627,644
Study Period Total Cost			5,950,210	6,110,386	6,582,945
Planning Rank			1	2	3
Study Rank			1	2	3

Table 9-18. HELCO Stuck in the Middle Environmental Compliance Resource Plans (2 of 2)

Name	**Self Generation**		**H2B2a_X-4Ar3b**	**H2B2a_X-4Ar4**
Plan	Annual	Cumulative	Retire Existing Replace with Geothermal	Year 2022 Fuel Switch to LSIFO, LNG
Notes			All Units except Keahole CC are Retired by Dec 2020 Cycle Hill 5/6, Puna Steam	Fuel Switch to LSIFO for Hill 5, Hill 6, and Puna Steam Fuel Switch to LNG for Keahole CC Cycle Hill 5–6, Puna Steam
Resources Available			None	None
2014	2MW	8MW	75% PBFA DSM	75% PBFA DSM
			Hu Honua (21.5MW)	Hu Honua (21.5MW)
2015	2MW	10MW	Retire Shipman 3 (–6.8 MW)	Retire Shipman 3 (–6.8 MW)
			Retire Shipman 4 (–6.7 MW)	Retire Shipman 4 (–6.7 MW)
			Add 5MW PV(HP03x5)	Add 5MW PV(HP03x5)
2016	2MW	12MW		
2017	2MW	14MW	Add 10MW wind (HW04x1)	Add 10MW wind (HW04x1)
2018	2MW	15MW		
2019	2MW	17MW	Retire Hill 5 (–13.5 MW)	Add 25MW geothermal (HG01x1)
2020	2MW	19MW	Add 10MW wind (HW04x1)	Add 10MW wind (HW04x1)
			Retire Hill 6 (–20 MW) Retire Puna Steam (–15.5 MW) Retire KanoeID 11,15–17 (–9.5 MW) Retire WaimeaD 12–14 (–7.5 MW) Retire KeahoID 21–23 (–7.5 MW) Retire Kanoe CT1 (–10.25 MW) Retire Keaho CT2 (–13.80 MW) Retire Puna CT3 (–19 MW) Retire PanaewD, OuliD, PunaluD, KapuaD (–4 MW)	
2021	2MW	21MW	Add 25MW geothermal (HG01x1)	
			Add 75MW new geothermal (HG02x3)	
2022	2MW	22MW		Fuel switch to LSIFO (Hill 5/6, Puna Steam)
				Fuel switch to LNG (Keahole CC)
			Add 5MW PV(HP03x5)	Add 5MW PV(HP03x5)
2023	1MW	24MW	Add 5MW PV(HP03x5)	Add 5MW PV(HP03x5)
2024	2MW	25MW	Add 25MW new geothermal (HG02x1)	
			Add 5MW PV(HP03x5)	Add 5MW PV(HP03x5)
2025	2MW	27MW		
2026	2MW	29MW		
2027	2MW	30MW		
2028	2MW	32MW	Add 5MW PV(HP03x5)	Add 5MW PV(HP03x5)
2029	2MW	33MW	Add 5MW PV(HP03x5)	Add 5MW PV(HP03x5)
2030	2MW	35MW	Add 10MW wind (HW04x1)	Add 10MW wind (HW04x1)

Name	Self Generation		H2B2a_X-4Ar3b	H2B2a_X-4Ar4
2031	2MW	37MW	Add 10MW wind (HW04x1)	Add 10MW wind (HW04x1)
2032	2MW	38MW		
2033	1MW	40MW		Add 25MW geothermal (HG02x1)
			Add 5MW PV(HP03x5)	Add 5MW PV(HP03x5)
Strategist Planning Period Total Cost			4,427,969	3,943,474
Strategist Study Period Total Cost			6,523,213	5,858,365
Planning Period Total Cost			4,624,343	5,348,680
Study Period Total Cost			6,578,066	7,702,646
Planning Rank			3	6
Study Rank			3	6

Table 9-19. HELCO No Burning Desire Environmental Compliance Resource Plans (1 of 2)

Name	Self Generation		H3B2A_N-2r2	H3B2A_N-4r1	H3B2A_N-4r2b
Plan	Annual	Cumulative	Year 2022 Fuel Switch to LSIFO	Year 2022 Install Air Quality Controls	Retire Existing Replace with Conventional Biofuel Units
Notes			Fuel Switch applies to Hill 5, Hill 6, and Puna Steam Cycle H5/6, Puna Steam	Cycle H5/6, Puna Steam	All Units except Keahole CC are Retired by Dec 2020 Cycle H5/6, Puna Steam
Resources Available			1 MW PV (HP03): 2015 17MW ICE (HS01): 2016 25MW Geo (HG01): 2016 25MW Geo (HG02): 2016 10MW Wind (HW04): 2017 50 MW Trough PV (HP04): 2020 15MW Ocean Wave (HV02): 2020	All units are fixed	21MW CT (HS05): 2020 63MW DTCC (HC05/HC06): 2020
2014	1MW	5MW	New CIDLC, Fast DR, RDLCWH, RDLCAC	New CIDLC, Fast DR, RDLCWH, RDLCAC	New CIDLC, Fast DR, RDLCWH, RDLCAC
			75% PBFA DSM	75% PBFA DSM	75% PBFA DSM
			Hu Honua (21.5MW)	Hu Honua (21.5MW)	Hu Honua (21.5MW)
2015	1MW	6MW	Retire Shipman 3 (–6.8 MW)	Retire Shipman 3 (–6.8 MW)	Retire Shipman 3 (–6.8 MW)
			Retire Shipman 4 (–6.7 MW)	Retire Shipman 4 (–6.7 MW)	Retire Shipman 4 (–6.7 MW)
2016	1MW	7MW			
2017	1MW	8MW	Add 25 MW geothermal (HG01x1)	Add 25 MW geothermal (HG01x1)	Add 25 MW geothermal (HG01x1)
			Add 10 MW wind (HW04x1)	Add 10 MW wind (HW04x1)	Add 10 MW wind (HW04x1)
2018	1MW	9MW			
2019	1MW	10MW			Retire Hill 5 (–13.5 MW)
2020	1MW	11MW	Add 10 MW wind (HW04x1)	Add 10 MW wind (HW04x1)	Add 10 MW wind (HW04x1)
					Retire Hill 6 (–20 MW) Retire Puna Steam (–15.5 MW) Retire KanoeID 11,15–17 (–9.5 MW) Retire WaimeaD 12–14 (–7.5 MW) Retire KeaholD 21–23 (–7.5 MW) Retire Kanoe CT1 (–10.25 MW) Retire Keaho CT2 (–13.80 MW) Retire Puna CT3 (–19 MW) Retire PanaewD, OuliD, PunaluD, KapuaD (–4 MW)
2021	1MW	12MW			Add 21MW CT (HS05x1); biofuel
					Add 63MW dual-train CC (HC05x1, HC06x1)
2022	1MW	13MW	Fuel switch to LSIFO (Hill 5/6, Puna Steam)	AQC for Hill 5/6, Puna Steam	
2023	1MW	14MW			
2024	1MW	15MW			Add 21MW CT (HS05x1); biofuel

Name	Self Generation		H3B2A_N-2r2	H3B2A_N-4r1	H3B2A_N-4r2b
2025	1MW	16MW	Add 17MW ICE (HS01x1); biofuel	Add 17MW ICE (HS01x1); biofuel	
2026	1MW	17MW			
2027	1MW	18MW			
2028	1MW	19MW			
2029	1MW	20MW			
2030	1MW	20MW	Add 10 MW wind (HW04x1)	Add 10 MW wind (HW04x1)	Add 10 MW wind (HW04x1)
					Add 21MW CT (HS05x1); biofuel
2031	1MW	21MW	Add 10 MW wind (HW04x1)	Add 10 MW wind (HW04x1)	Add 10 MW wind (HW04x1)
2032	1MW	22MW			
2033	1MW	23MW			
Strategist Planning Period Total Cost			3,847,810.000	3,821,742.000	4,794,787.500
Strategist Study Period Total Cost			5,632,635.500	5,580,069.500	7,070,659.500
Planning Period Total Cost			4,493,985.270	4,632,831.262	5,441,969.402
Study Period Total Cost			6,608,560.588	6,933,651.418	7,717,841.512
Planning Rank			1	2	3
Study Rank			1	2	3

Table 9-20. HELCO No Burning Desire Environmental Compliance Resource Plans (2 of 2)

Name	Self Generation		H3B2A_N-4r3b	H3B2A_N-4r4
Plan	Annual	Cumulative	Retire Existing Replace with Geothermal	Year 2022 Fuel Switch to LSIFO, LNG
Notes			All Units except Keahole CC are Retired by Dec 2020	Fuel Switch to LSIFO for Hill 5, Hill 6, and Puna Steam
			Cycle H5/6, Puna Steam	Fuel Switch to LNG for Keahole CC
				Cycle Hill 5–6, Puna Steam
Resources Available			25MW Geo (HG01): 2020	All resources are fixed
			25MW Geo (HG02): 2020	
2014	1MW	5MW	New CIDLC, Fast DR, RDLCWH, RDLCAC	New CIDLC, Fast DR, RDLCWH, RDLCAC
			75% PBFA DSM	75% PBFA DSM
			Hu Honua (21.5MW)	Hu Honua (21.5MW)
2015	1MW	6MW	Retire Shipman 3 (–6.8 MW)	Retire Shipman 3 (–6.8 MW)
			Retire Shipman 4 (–6.7 MW)	Retire Shipman 4 (–6.7 MW)
2016	1MW	7MW		
2017	1MW	8MW	Add 25 MW geothermal (HG01x1)	Add 25 MW geothermal (HG01x1)
			Add 10 MW wind (HW04x1)	Add 10 MW wind (HW04x1)
2018	1MW	9MW		
2019	1MW	10MW	Retire Hill 5 (–13.5 MW)	
2020	1MW	11MW	Add 10 MW wind (HW04x1)	Add 10 MW wind (HW04x1)
			Add 50MW new geothermal (HG02x2)	
			Retire Hill 6 (–20 MW) Retire Puna Steam (–15.5 MW) Retire KanoelD 11,15–17 (–9.5 MW) Retire WaimeaD 12–14 (–7.5 MW) Retire KeaholD 21–23 (–7.5 MW) Retire Kanoe CT1 (–10.25 MW) Retire Keaho CT2 (–13.80 MW) Retire Puna CT3 (–19 MW) Retire PanaewD, OuliD, PunaluD, KapuaD (–4 MW)	
2021	1MW	12MW	Add 75MW new geothermal (HG02x3)	
2022	1MW	13MW		Fuel switch to LSIFO (Hill 5/6, Puna Steam)
				Fuel switch to LNG (Keahole CC)
2023	1MW	14MW		
2024	1MW	15MW		
2025	1MW	16MW		Add 17MW ICE (HS01x1); biofuel
			Add 50MW new geothermal (HG02x2)	
2026	1MW	17MW		
2027	1MW	18MW		
2028	1MW	19MW		
2029	1MW	20MW		

Name	**Self Generation**		**H3B2A_N-4r3b**	**H3B2A_N-4r4**
2030	1MW	20MW	Add 10 MW wind (HW04x1)	Add 10 MW wind (HW04x1)
2031	1MW	21MW	Add 10 MW wind (HW04x1)	Add 10 MW wind (HW04x1)
2032	1MW	22MW		
2033	1MW	23MW		
Strategist Planning Period Total Cost			4,701,397.000	3,947,967.200
Strategist Study Period Total Cost			6,871,412.500	5,871,025.000
Planning Period Total Cost			5,348,579.309	4,600,457.812
Study Period Total Cost			7,518,594.512	6,542,787.322
Planning Rank			4	2
Study Rank			4	1

Table 9-21. HELCO Moved by Passion Environmental Compliance Resource Plans (1 of 2)

Name	Self Generation		H4B2A_X-2Ar3	H4B2A_X-4Ar1	H4B2A_X-4Ar2b
Plan	Annual	Cumulative	Year 2022 Fuel Switch to LSIFO	Year 2022 Install Air Quality Controls	Retire Existing Replace with Conventional Biofuel Units
Notes			Fuel Switch applies to Hill 5, Hill 6, and Puna Steam Cycle Hill 5/6, Puna Steam	Cycle Hill 5/6, Puna Steam	All Units except Keahole CC are Retired by December 2020 Cycle Hill 5/6, Puna Steam
Resources Available			1 MW PV (HP03): 2015 10MW Wind (HW02): 2017 25MW Geothermal (HG01): 2017 Puna Repower (HRP1): 2018 25MW Geothermal (HG02): 2020 50 MW Trough PV (HP04): 2020 15MW Ocean Wave (HV02): 2020	Puna Repower (HRP1): 2018	21MW CT (HS05): 2021 63MW DTCC (HC05/HC06): 2021
2014	4MW	14MW	75%+25% PBFA DSM	75%+25% PBFA DSM	75%+25% PBFA DSM
			Hu Honua (21.5MW)	Hu Honua (21.5MW)	Hu Honua (21.5MW)
2015	4MW	18MW	Deactivate Shipman 3 (–6.8 MW)	Retire Shipman 3 (–6.8 MW)	Retire Shipman 3 (–6.8 MW)
			Deactivate Shipman 4 (–6.7 MW)	Retire Shipman 4 (–6.7 MW)	Retire Shipman 4 (–6.7 MW)
			Add 5MW PV (HP03x5)	Add 5MW PV (HP03x5)	Add 5MW PV (HP03x5)
2016	4MW	22MW			
2017	4MW	25MW	Add 25MW geothermal (HG01x1)	Add 25MW geothermal (HG01x1)	
			Add 10MW wind (HW04x1)	Add 10MW wind (HW04x1)	Add 10MW wind (HW04x1)
2018	3MW	28MW			
2019	3MW	32MW			Retire Hill 5 (–13.5 MW)
2020	3MW	35MW	Add 10MW wind (HW04x1)	Add 10MW wind (HW04x1)	Add 10MW wind (HW04x1)
					Retire Hill 6 (–20 MW) Retire Puna Steam (–15.5 MW) Retire KanoeID 11,15–17 (–9.5 MW) Retire WaimeaD 12–14 (–7.5 MW) Retire KeaholD 21–23 (–7.5 MW) Retire Kanoe CT1 (–10.25 MW) Retire Keaho CT2 (–13.80 MW) Retire Puna CT3 (–19 MW) Retire PanaewD, OuliD, PunaluD, KapuaD (–4 MW)
			Add 5MW PV (HP03x5)	Add 5MW PV (HP03x5)	Add 5MW PV (HP03x5)
2021	3MW	38MW	Add 5MW PV (HP03x5)	Add 5MW PV (HP03x5)	Add 5MW PV (HP03x5)
			Add 10MW wind (HW04x1)	Add 10MW wind (HW04x1)	Add 21MW CT (HS05x1); biofuel
					Add 63MW dual-train CC (HC05x1, HC06x1)
2022	3MW	41MW	Fuel switch to LSIFO (Hill 5/6, Puna Steam)	AQC for Hill 5/6, Puna Steam	
			Add 10MW wind (HW04x1)	Add 10MW wind (HW04x1)	Add 10MW wind (HW04x1)
2023	3MW	43MW			

Name	Self Generation		H4B2A_X-2Ar3	H4B2A_X-4Ar1	H4B2A_X-4Ar2b
2024	3MW	46MW	Add 5MW PV (HP03x5)	Add 5MW PV (HP03x5)	Add 5MW PV (HP03x5)
2025	3MW	49MW			
2026	3MW	52MW			
2027	3MW	55MW			
2028	3MW	59MW	Add 5MW PV (HP03x5)	Add 5MW PV (HP03x5)	Add 5MW PV (HP03x5)
2029	3MW	61MW	Add 5MW PV (HP03x5)	Add 5MW PV (HP03x5)	Add 5MW PV (HP03x5)
2030	3MW	64MW			
2031	3MW	67MW			
2032	3MW	71MW			
2033	3MW	73MW	Add 25MW geothermal (HG02x1)	Add 25MW geothermal (HG02x1)	
			Add 5MW PV (HP03x5)	Add 5MW PV (HP03x5)	Add 5MW PV (HP03x5)
Strategist PV Planning Period Total Cost			3,959,051	3,958,532	4,677,479
Strategist PV Study Period Total Cost			5,622,139	5,621,328	6,689,785
PV Planning Period Total Cost			4,665,916	4,835,576	5,385,351
PV Study Period Total Cost			6,329,003	6,493,106	7,397,656
Planning Rank			2	3	5
Study Rank			2	3	5

Table 9-22. HELCO Moved by Passion Environmental Compliance Resource Plans (2 of 2)

Name	**Self Generation**		**H4B2A_X-4Ar3b**	**H4B2A_X-4Ar4**
Plan	Annual	Cumulative	Retire Existing Replace with Geothermal	Year 2022 Fuel Switch to LSIFO, LNG
Notes			All Units except Keahole CC are retired by December 2020 Cycle Hill 5–6, Puna Steam	Fuel Switch to LSIFO for Hill 5, Hill 6, and Puna Steam Fuel Switch to LNG for Keahole CC Cycle Hill 5–6, Puna Steam
Resources Available			25MW Geo (HG01): 2021 25MW Geo (HG02): 2021	Puna Repower (HRP1): 2018
2014	4MW	14MW	75%+25% PBFA DSM	75%+25% PBFA DSM
			Hu Honua (21.5MW)	Hu Honua (21.5MW)
2015	4MW	18MW	Retire Shipman 3 (–6.8 MW)	Retire Shipman 3 (–6.8 MW)
			Retire Shipman 4 (–6.7 MW)	Retire Shipman 4 (–6.7 MW)
			Add 5MW PV (HP03x5)	Add 5MW PV (HP03x5)
2016	4MW	22MW		
2017	4MW	25MW		Add 25MW geothermal (HG01x1)
			Add 10MW wind (HW04x1)	Add 10MW wind (HW04x1)
2018	3MW	28MW		
2019	3MW	32MW	Retire Hill 5 (–13.5 MW)	
2020	3MW	35MW	Add 10MW wind (HW04x1)	Add 10MW wind (HW04x1)
			Retire Hill 6 (–20 MW) Retire Puna Steam (–15.5 MW) Retire KanoeID 11,15–17 (–9.5 MW) Retire WaimeaD 12–14 (–7.5 MW) Retire KeahoID 21–23 (–7.5 MW) Retire Kanoe CT1 (–10.25 MW) Retire Keaho CT2 (–13.80 MW) Retire Puna CT3 (–19 MW) Retire PanaewD, OuliD, PunaluD, KapuaD (–4 MW)	
			Add 5MW PV (HP03x5)	Add 5MW PV (HP03x5)
2021	3MW	38MW	Add 5MW PV (HP03x5)	Add 5MW PV (HP03x5)
			Add 25MW geothermal (HG01x1)	Add 10MW wind (HW04x1)
			Add 75MW new geothermal (HG02x3)	
2022	3MW	41MW		Fuel switch to LSIFO (Hill 5/6, Puna Steam) Fuel switch to LNG (Keahole CC)
			Add 10MW wind (HW04x1)	Add 10MW wind (HW04x1)
2023	3MW	43MW		
2024	3MW	46MW	Add 5MW PV (HP03x5)	Add 5MW PV (HP03x5)
2025	3MW	49MW		
2026	3MW	52MW		
2027	3MW	55MW		
2028	3MW	59MW	Add 5MW PV (HP03x5)	Add 5MW PV (HP03x5)

Name	Self Generation		H4B2A_X-4Ar3b	H4B2A_X-4Ar4
2029	3MW	61MW	Add 5MW PV (HP03x5)	Add 5MW PV (HP03x5)
2030	3MW	64MW		
2031	3MW	67MW		
2032	3MW	71MW		
2033	3MW	73MW		Add 25MW geothermal (HG02x1)
			Add 5MW PV (HP03x5)	Add 5MW PV (HP03x5)
Strategist PV Planning Period Total Cost			4,344,435	3,921,988
Strategist PV Study Period Total Cost			6,097,962	5,550,993
PV Planning Period Total Cost			5,052,306	4,636,276
PV Study Period Total Cost			6,805,833	6,264,173
Planning Rank			4	1
Study Rank			4	1

HELCO Total Resource Costs

For all scenarios, the analysis shows that, in general, switching fuels results in lower total resource costs (TRC) — utility capital, operations and maintenance, and customer costs) — than installing AQC equipment. Retire-and-replace strategies also have higher costs than the fuel switching strategies. Table 9-23 shows a heat map of how the environmental strategies TRC ranks in each scenario.

Table 9-23. HELCO Heat Map of Total Resource Cost of Environmental Strategies by Scenario (Thousands)

Strategies	Blazing a Bold Frontier	Stuck in the Middle	No Burning Desire	Moved by Passion
1. Fuel Switch to Low Sulfur Industrial Fuel Oil	$6,303,754	$5,950,210	$6,608,561	$6,329,003
2. Install AQC Equipment	$6,462,721	$6,110,386	$6,933,651	$6,493,106
3. Fuel Switch to Biofuels	$5,706,082	n/a	n/a	n/a
4. Fuel Switch to LSIFO/LNG	$6,085,324	$7,702,646	$6,542,787	$6,264,173
5. Retire and Replace with Geothermal	$6,799,808	$6,578,066	$7,518,595	$6,805,833
6. Retire and Replace with Biofuel Units	$6,548,018	$6,582,945	$7,717,842	$7,397,656

BEST						WORST

HELCO Fuel Switching Strategies

The fuel switching strategies also lower utility capital costs, reflected in the annual revenue requirements for capital metric (Figure 9-20 to Figure 9-23), which depicts the differences in capital costs between the different environmental compliance plans.

The strategies that retire existing units and replace them with new generation have the highest capital costs, higher than installing more than $200 million in AQC equipment.

Figure 9-20. HELCO Blazing a Bold Frontier Annual Revenue Requirements of Environmental Compliance Strategies

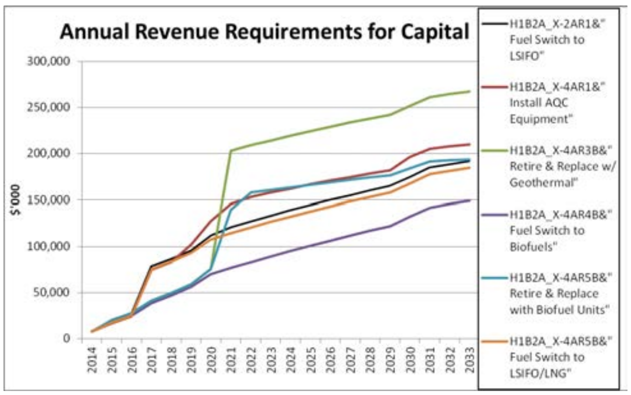


Figure 9-21. HELCO Stuck in the Middle Annual Revenue Requirements of Environmental Compliance Strategies

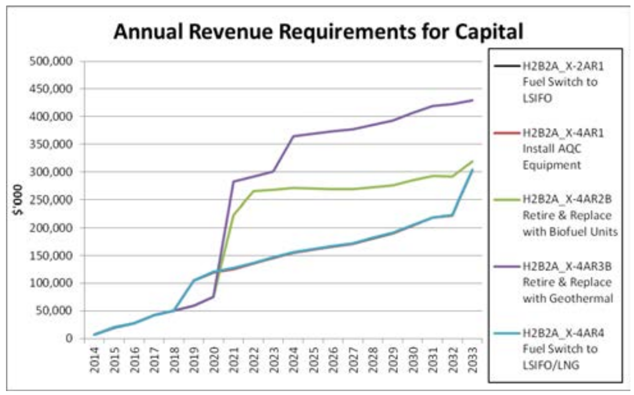


Figure 9-22. HELCO No Burning Desire Annual Revenue Requirements of Environmental Compliance Strategies

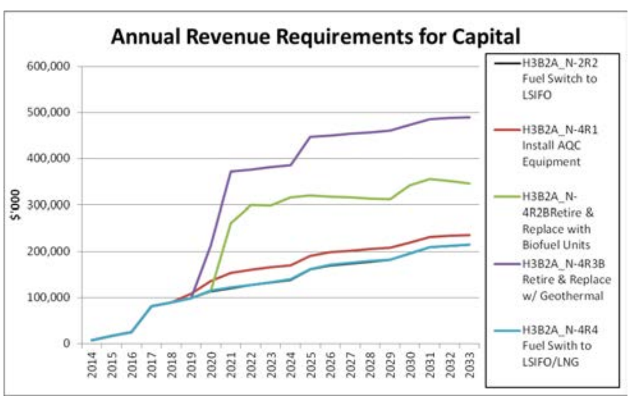
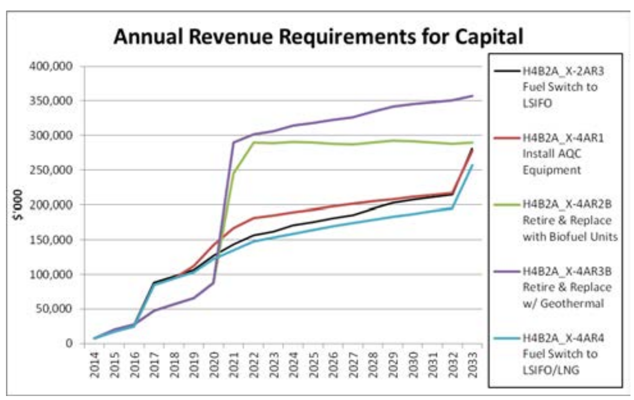


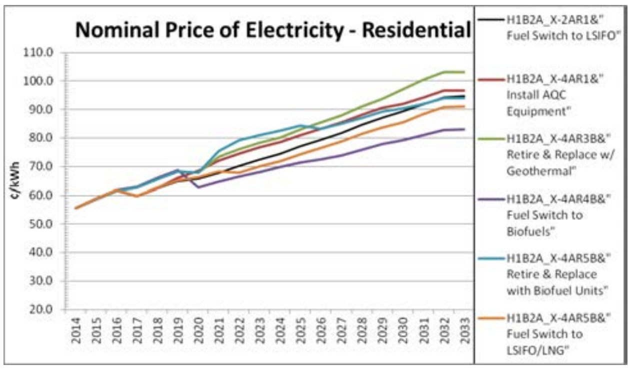
Figure 9-23. HELCO Moved by Passion Annual Revenue Requirements of Environmental Compliance Strategies



HELCO Resource Plan Costs

Retiring units and replacing them with new generation as well as installing AQC equipment would result in the highest rates in any scenario (Figure 9-24 to Figure 9-27). In three of the four scenarios, switching to LSIFO has the lowest rate impact, on par with switching the Keahole combined cycle unit to LNG. For Blazing a Bold Frontier, switching existing units to biofuels would result in the lowest rates because biofuels costs decline over time.

Figure 9-24. HELCO Blazing a Bold Frontier Estimated Residential and Commercial Rate Impacts for Environmental Compliance Strategies



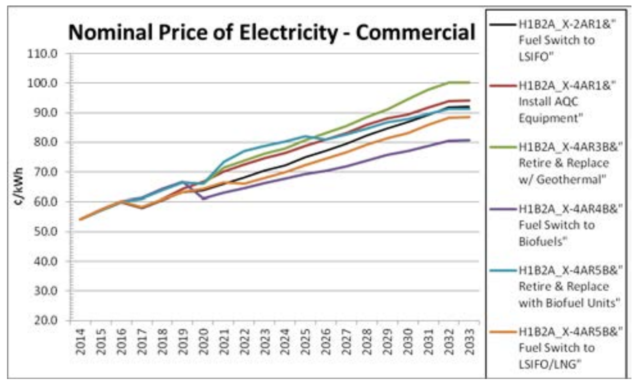
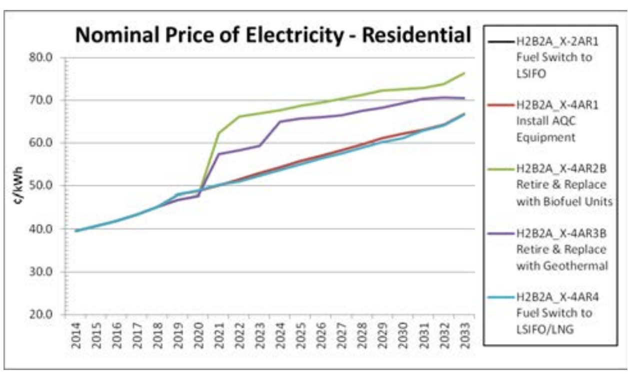


Figure 9-25. HELCO Stuck in the Middle Estimated Residential and Commercial Rate Impacts for Environmental Compliance Strategies



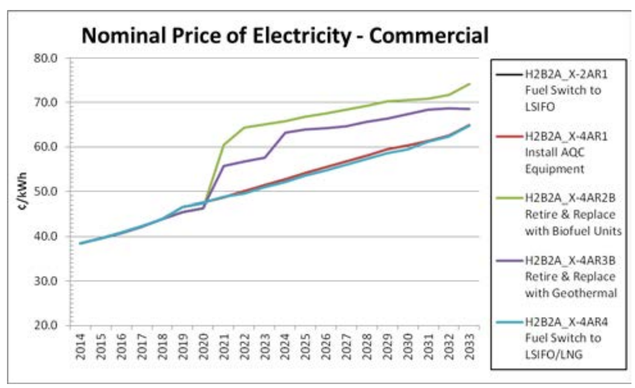
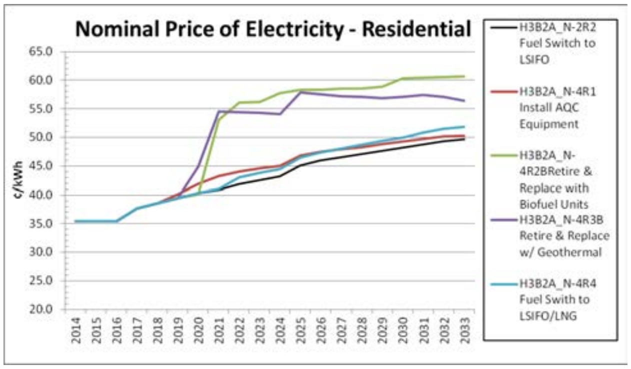


Figure 9-26. HELCO No Burning Desire Estimated Residential and Commercial Rate Impacts for Environmental Compliance Strategies



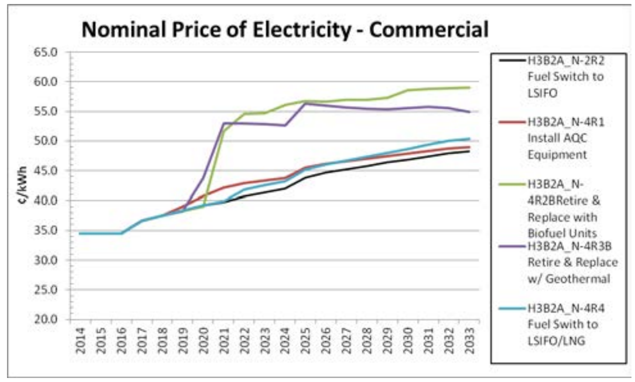
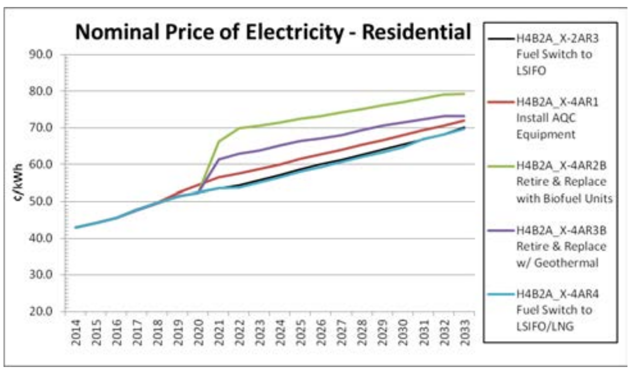
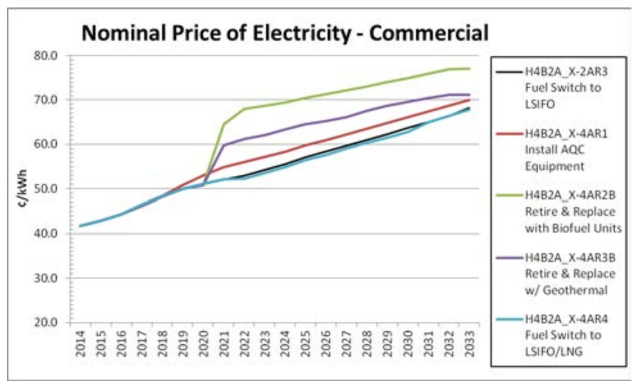


Figure 9-27. HELCO Moved by Passion Estimated Residential and Commercial Rate Impacts for Environmental Compliance Strategies





HELCO Conclusion

Switching fuels to LSIFO is the most robust, cost-effective strategy.

MECO Environmental Compliance

MECO focused on complying with the NAAQS regulations by analyzing several strategies.

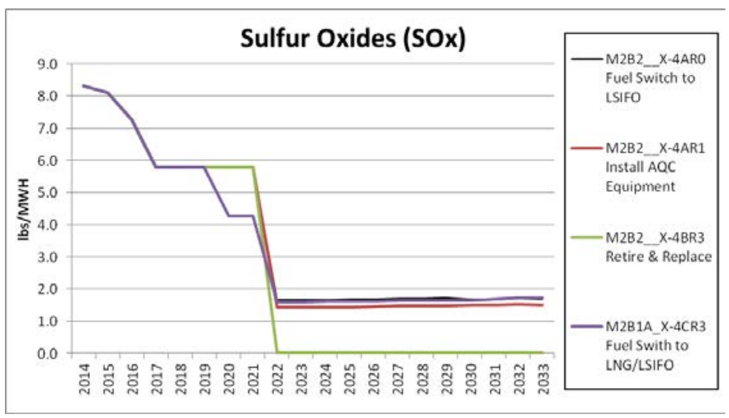
MECO NAAQS Compliance Strategy

MECO analyzed:

- Switching to lower sulfur fuels such as Low Sulfur Industrial Fuel Oil (LSIFO), biofuels, or LNG only for the Maalaea combined cycle units.
- Installing AQC equipment on Kahului units 1 through 4.
- Retiring existing units and replacing them with new firm geothermal or biofuel generation.

Figure 9-28 illustrates SO_2 emission reductions achieved by the strategies in all scenarios to comply with NAAQS regulations.

Figure 9-28. MECO Typical Illustration of Sulfur Dioxide Emission Reductions Achieved by Strategies



MECO Resource Plans

MECO developed several resource plans by modeling these compliance strategies in each of the four scenarios. Table 9-24 through Table 9-27 summarizes all of these resource plans.

Table 9-24. MECO Blazing a Bold Frontier Environmental Compliance Resource Plans

Name	Self Generation		M1_2a_X-1r3	M1B2a_X-4Br2	M1C2a_X-3Cr4	M1C2a_X-3Cr3
Plan	Annual	Cumulative	HC&S contract terminated 2014 Continue Fossil Fuel	HC&S contract terminated 2014 Kahului continues to use MSFO Fuel Switch at Maalaea to S500 Diesel 2022 Install AQC for K1–K4	HC&S contract terminated 2014	HC&S contract terminated 2014
Notes			Environmental Compliance Run Existing Units Continue to use Fossil Fuel (Kahului fuel switch to LSIFO, Maalaea fuel switch to S500 in 2022) No Retirements	Environmental Compliance Run Excising Units Continue to use Fossil Fuel (Kahului fuel continue MSFO with AQC equipment installed, Maalaea fuel switch to S500 in 2022) No Existing Unit Retirements	Unit Timing 17MW ICE, 5MW ICE, LM2500, Geo, Biomass, WTE 100% RE Excising Units Switch to Biofuel 2020 Retire existing units (K1–K4, MX1–M11) on Remaining Useful Life	Unit Timing Rule 1 17MW ICE, 5MW ICE, LM2500, Geo, WTE, Biomass 100% RE Excising Units Switch to Biofuel 2020 No Retirements
2014	17MW	40MW	HC&S contract terminated 2014 110% of base EEPS Fast DR only	HC&S contract terminated 2014 110% of base EEPS Fast DR only	HC&S contract terminated 2014 110% of base EEPS Fast DR only	HC&S contract terminated 2014 110% of base EEPS Fast DR only
2015	16MW	56MW				
2016	17MW	73MW				
2017	16MW	89MW				
2018	14MW	103MW				
2019	10MW	113MW				
2020	8MW	121MW			Fuel switch to biofuels	Fuel switch to biofuels
2021	5MW	126MW				
2022	4MW	130MW	Fuel switch to LSIFO (K1–K4) Fuel switch to ULSD (Maalaea)	Fuel switch to ULSD (Maalaea) AQC for K1–K4		
2023	3MW	134MW			Retire M4–M5 (end of year)	
2024	3MW	137MW				
2025	2MW	138MW			Retire K1–K4, M6–M7 (end of year)	
2026	2MW	140MW			(1) 17 MW ICE; biofuel [MS01] Retire M1 (end of year)	

Name	Self Generation		M1_2a_X-1r3	M1B2a_X-4Br2	M1C2a_X-3Cr4	M1C2a_X-3Cr3
2027	2MW	142MW			Retire M2, M3, M8 (end of year)	
2028	2MW	144MW			(1) 17 MW ICE; biofuel [MS01] Retire M9 (end of year)	
2029	1MW	145MW			Retire M10 (end of year)	
2030	1MW	146MW			(1) 17 MW ICE; biofuel [MS01] Retire M11 (end of year)	
2031	1MW	147MW				
2032	2MW	149MW			Retire MX1, MX2 (end of year)	
2033	1MW	149MW				
Strategist Planning Total Cost			5,995,727.50	5,948,954.00	4,643,764.50	4,796,451.50
Study Total Cost			8,316,523.00	8,223,982.00	5,354,190.50	5,613,973.00
Planning Total Cost			6,764,417.73	6,883,619.13	5,387,050.55	5,565,141.61
Study Total Cost			9,085,213.81	9,158,646.49	6,097,476.60	6,382,663.81
Planning Rank			3	4	1	2
Study Rank			3	4	1	2

Table 9-25. MECO Stuck in the Middle Environmental Compliance Resource Plans

Name	**Self Generation**		**M2B2__X-4Ar0**	**M2B2__X-4Ar1**	**M2B2__X-4Br3**	**M2B1a_X-4Cr3**
Plan			SitM Env Comp	SitM Env Comp	SitM Env Comp	SitM Env Comp
Notes	Annual	Cumulative	Fuel Switch Allow ICE 17MW Allow Wind, PV, Wave (Curtailed OK)	No Kahului Fuel Switch Allow ICE 17MW Allow Wind, PV, Wave (Curtailed OK)	Retire for Environmental Compliance except Maalaea DTCC Allow ICEs, CT, CC allow limited WindC7, TrPV, Wave (Curtailed OK)	LNG Fuel Switch Allow ICE 17MW Allow 9x WindC7, 2x TrPV (Curtailed OK)
Reference						
2014	9MW	22MW	75% of base EEPS Fast DR only	75% of base EEPS Fast DR only	75% of base EEPS Fast DR only	75% of base EEPS Fast DR only
2015	9MW	31MW	3x Wind (10 MW)	3x Wind (10 MW)	3x Wind (10 MW)	3x Wind (10 MW)
2016	9MW	40MW	3x Wind (10 MW)	3x Wind (10 MW)	3x Wind (10 MW)	3x Wind (10 MW)
2017	10MW	49MW	3x Wind (10 MW)	3x Wind (10 MW)	3x Wind (10 MW)	3x Wind (10 MW)
2018	8MW	56MW				
2019	5MW	62MW				
2020	4MW	66MW				Fuel switch to LNG (Maalaea DTCCs)
2021	3MW	69MW			Retire K1–K4, X1–X2, M1–M13	
2022	2MW	71MW	Fuel switch to LSIFO (K1–K4) Fuel switch to ULSD (Maalaea)	AQC for K1–K4	6x ICE biofuel (17 MW)	Fuel switch to LSIFO (K1–K4)
				Fuel switch to ULSD (Maalaea)	Fuel switch to ULSD (Maalaea)	Fuel switch to ULSD (Maalaea)
					2x biofuel combustion turbine (21 MW)	
					PV (5 MW)	
2023	2MW	142MW	ICE biofuel (17 MW)	ICE biofuel (17 MW)		ICE biofuel (17 MW)
2024	2MW	73MW				
2025	1MW	75MW				
2026	1MW	76MW				
2027	1MW	77MW				
2028	1MW	78MW				
2029	1MW	79MW				
2030	1MW	80MW	PV (5MW)			
2031	1MW	80MW				
2032	1MW	81MW				
2033	0MW	81MW	PV (5MW)	PV (5MW)		

Name	Self Generation		M2B2__X-4Ar0	M2B2__X-4Ar1	M2B2__X-4Br3	M2B1a_X-4Cr3
Strategist Planning Total Cost			3,998,184	3,956,761	4,305,946	3,874,682
Strategist Study Total Cost			5,958,626	5,873,092	6,244,786	5,696,040
Planning Total Cost			4,770,529	4,895,079	5,058,931	4,656,500
Study Total Cost			6,730,971	6,811,411	6,997,771	6,477,858
Planning Rank			2	3	4	1
Study Rank			2	3	4	1

Table 9-26. MECO No Burning Desire Environmental Compliance Resource Plans

Name	Self Generation		M3_2a_N-2r4	M3B2a_N-4Br0	M3B2a_N-4Br8	M3B1a_N-4Cr0
	Annual	Cumulative				
Plan			NBD Kahului Fuel Switch to LSIFO and Fuel Switch at Maalaea to S500 Diesel 2022.	NBD Kahului continues to use MSFO Fuel Switch at Maalaea to S500 Diesel 2022	NBD Kahului Fuel Switch to LSIFO and Fuel Switch at Maalaea to S500 Diesel 2022. Unit Retirements	NBD Existing DTCC units (M141516, M171819) switch to LNG 2020. Kahului Units Switch to LSIFO and Fuel Switch at Maalaea to S500 Diesel 2022. No Unit Retirements
Notes			Firm Resource Timing on Rule 1, fixed from Unit Timing Run M3_2a_N-2r3, All DR, HC&S contract expires 12/31/2014 No Existing Unit Retirements	Environmental Compliance Run; Unit Timing 17MW ICE, 5MW ICE, LM2500, LM2500 DTCC, Geo, Bio, WTE; Existing Units Continue to use Fossil Fuel (Kahului fuel continue MSFO, Maalaea fuel switch to S500 in 2022); No Existing Unit Retirements	Environmental Compliance Run; Unit Timing 17MW ICE, LM2500, Geo, Bio; Existing Units Continue to use Fossil Fuel (Kahului fuel switch to LSIFO, Maalaea fuel switch to S500 in 2022); Retire existing units (K1–K4, MX1–M13) Dec 2021	Environmental Compliance Run Same unit timing as plan 'M3B2a_N-4Br0' No Existing Unit Retirements New units use Biofuel
2014	5MW	13MW	75% of base EEPS All DR: CIDLC Exp, RDLC Exp, Fast DR	75% of base EEPS All DR: CIDLC Exp, RDLC Exp, Fast DR	75% of base EEPS All DR: CIDLC Exp, RDLC Exp, Fast DR	75% of base EEPS All DR: CIDLC Exp, RDLC Exp, Fast DR
2015	5MW	18MW	(3) 5 MW ICE; biofuel [MS14]	(3) 5 MW ICE; biofuel [MS14]	(3) 5 MW ICE; biofuel [MS14]	(3) 5 MW ICE; biofuel [MS14]
			(3) 10 MW wind [MW04]	(3) 10 MW wind [MW04]	(3) 10 MW wind [MW04]	(3) 10 MW wind [MW04]
2016	5MW	23MW	(1) 21 MW SC LM2500; biofuel [MS05]	(1) 21 MW SC LM2500; biofuel [MS05]	(1) 21 MW SC LM2500; biofuel [MS05]	(1) 21 MW SC LM2500; biofuel [MS05]
			(2) 10 MW wind [MW04]	(2) 10 MW wind [MW04]	(2) 10 MW wind [MW04]	(2) 10 MW wind [MW04]
2017	5MW	28MW				
2018	4MW	33MW	(1) 10 MW wind [MW04]	(1) 10 MW wind [MW04]	(1) 10 MW wind [MW04]	(1) 10 MW wind [MW04]
2019	3MW	36MW	(1) 21 MW SC LM2500; biofuel [MS05]	(1) 21 MW SC LM2500; biofuel [MS05]	(1) 21 MW SC LM2500; biofuel [MS05]	(1) 21 MW SC LM2500; biofuel [MS05]
2020	2MW	39MW	(1) 10 MW wind [MW04]	(1) 10 MW wind [MW04]	(1) 10 MW wind [MW04]	(1) 10 MW wind [MW04]
						Fuel switch to LNG (Maalaea DTCCs)
2021	2MW	40MW	(1) 10 MW wind [MW04]	(1) 10 MW wind [MW04]	(1) 10 MW wind [MW04]	(1) 10 MW wind [MW04]
					Retire MX1, MX2, M1–M13, K1–K4 (end of year)	

Name	Self Generation		M3_2a_N-2r4	M3B2a_N-4Br0	M3B2a_N-4Br8	M3B1a_N-4Cr0
2022	1MW	41MW	(1) 17 MW ICE; biofuel [MS01]	(1) 17 MW ICE; biofuel [MS01]	(1) 25 MW new geothermal [MG02]	(1) 17 MW ICE; biofuel [MS01]
			(1) 10 MW wind [MW04]	(1) 10 MW wind [MW04]	(7) 17 MW ICE; biofuel [MS01]	(1) 10 MW wind [MW04]
					(1) 10 MW wind [MW04]	
			Fuel switch to LSIFO (K1–K4); Fuel switch to ULSD (Maalaea)	AQC for K1–K4	Fuel switch to ULSD (Maalaea)	Fuel switch to LSIFO (K1–K4); Fuel switch to ULSD (Maalaea)
				Fuel switch to ULSD (Maalaea)		
2023	1MW	43MW			(1) 25 MW new geothermal [MG02]	
2024	1MW	43MW	(1) 17 MW ICE; biofuel [MS01]	(1) 17 MW ICE; biofuel [MS01]		(1) 17 MW ICE; biofuel [MS01]
2025	1MW	44MW				
2026	1MW	45MW				
2027	1MW	45MW	(1) 25 MW new geothermal [MG02]	(1) 25 MW new geothermal [MG02]	(1) 17 MW ICE; biofuel [MS01]	(1) 25 MW new geothermal [MG02]
2028	1MW	46MW				
2029	0MW	46MW				
2030	0MW	46MW			(1) 25 MW Banagrass [MA01]	
2031	0MW	47MW	(1) 17 MW ICE; biofuel [MS01]	(1) 17 MW ICE; biofuel [MS01]		(1) 17 MW ICE; biofuel [MS01]
2032	1MW	47MW				
2033	0MW	48MW				
Strategist Planning Total Cost			4,792,560	4,747,788	5,361,927	5,088,994
Strategist Study Total Cost			7,068,077	6,983,382	7,888,491	7,782,747
Planning Total Cost			5,580,799	5,702,001	6,139,798	5,886,706
Study Total Cost			7,856,316	7,937,595	8,666,362	8,580,460
Planning Rank			1	2	4	3
Study Rank			1	2	4	3

Table 9-27. MECO Moved by Passion Environmental Compliance Resource Plans

Name	Self Generation		M4_2a_X-2r12	M4B2A_X-4Ar0	M4B2A_X-4Cr2	M4B1A_X-4Ar0
Plan	Annual	Cumulative	MBP Screening PV	MBP Environmental Compliance Run	MBP Consolidated, 100% Renewable	MBP Environmental Compliance Run, LNG DTCC
Notes			Without Geothermal, Plank Rank 1	Without Retirements, No KPP fuel switch, Install Air Quality Controls	With Retirements	Without Retirements, LNG DTCC, plan 1
Reference						
2014	15MW	37MW	100% of base EEPS Fast DR only	100% of base EEPS Fast DR only	100% of base EEPS Fast DR only	100% of base EEPS Fast DR only
2015	14MW	51MW	(5) 1 MW PV [MP03]	(5) 1 MW PV [MP03]	(5) 1 MW PV [MP03] (1) 10 MW wind [MW04]	(5) 1 MW PV [MP03]
2016	16MW	67MW	(5) 1 MW PV [MP03]	(5) 1 MW PV [MP03]	(5) 1 MW PV [MP03]	(5) 1 MW PV [MP03]
2017	15MW	81MW	(5) 1 MW PV [MP03]	(5) 1 MW PV [MP03]	(5) 1 MW PV [MP03]	(5) 1 MW PV [MP03]
2018	13MW	94MW	(5) 1 MW PV [MP03]	(5) 1 MW PV [MP03]	(5) 1 MW PV [MP03]	(5) 1 MW PV [MP03]
2019	9MW	103MW	(5) 1 MW PV [MP03]	(5) 1 MW PV [MP03]	(5) 1 MW PV [MP03]	(5) 1 MW PV [MP03]
2020	7MW	110MW	(5) 1 MW PV [MP03]	(5) 1 MW PV [MP03]		(5) 1 MW PV [MP03] Fuel switch to LNG (Maalaea DTCCs)
2021	5MW	115MW	(5) 1 MW PV [MP03]	(5) 1 MW PV [MP03]		(5) 1 MW PV [MP03]
2022	4MW	118MW	(5) 1 MW PV [MP03] Fuel switch to LSIFO (K1–K4) Fuel switch to ULSD (Maalaea)	(5) 1 MW PV [MP03] Fuel switch to ULSD (Maalaea) AQC for K1–K4	Retire MX1, MX2, M1–M13, K1–K4 (end of year) (1) 25 MW new geothermal [MG02] (6) 17 MW ICE [MS01]	Fuel switch to LSIFO (K1–K4) Fuel switch to ULSD (Maalaea)
2023	3MW	121MW	(5) 1 MW PV [MP03]			
2024	3MW	124MW			(1) 17 MW ICE [MS01]	
2025	2MW	126MW				
2026	2MW	127MW				
2027	1MW	129MW				
2028	2MW	131MW				
2029	1MW	131MW				(5) 1 MW PV [MP03]
2030	1MW	133MW		(5) 1 MW PV [MP03]		
2031	1MW	134MW				(5) 1 MW PV [MP03]
2032	1MW	135MW				

Name	Self Generation		M4_2a_X-2r12	M4B2A_X-4Ar0	M4B2A_X-4Cr2	M4B1A_X-4Ar0
2033	1MW	136MW	(5) 1 MW PV [MP03]	(5) 1 MW PV [MP03]		(5) 1 MW PV [MP03]
Strategist Planning Total Cost			4,459,951.33	4,412,678.00	4,740,492.50	4,269,261.50
Strategist Study Total Cost			6,418,476.00	6,324,584.00	6,642,028.00	6,052,690.00
Planning Total Cost			5,280,665.12	5,255,949.04	5,567,899.79	5,099,449.17
Study Total Cost			7,239,189.80	7,311,271.47	7,469,435.39	6,882,877.60
Planning Rank			3	2	4	1
Study Rank			2	3	4	1

MECO Total Resource Costs

For all scenarios, the analysis shows that, in general, switching fuels results in lower total resource costs (TRC) — utility capital, operations and maintenance, and customer costs — than installing AQC equipment. Except for Blazing a Bold Frontier where biofuel costs are low, retire-and-replace strategies also have higher costs than the fuel switching strategies. Table 9-28 shows a heat map of how the environmental strategies TRC ranks in each scenario.

Table 9-28. MECO Heat Map of Total Resource Cost of Environmental Strategies by Scenario (Thousands)

Strategies	Blazing a Bold Frontier	Stuck in the Middle	No Burning Desire	Moved by Passion
1. Fuel Switch to Low Sulfur Industrial Fuel Oil	$9,085,214	$6,730,971	$7,856,316	$7,239,190
2. Install AQC Equipment	$9,158,646	$6,811,411	$7,937,595	$7,311,271
3. Fuel Switch to Biofuels	$6,382,664	n/a	n/a	n/a
4. Fuel Switch to LSIFO/LNG	n/a	$6,477,858	$8,580,460	$6,882,878
6. Retire and Replace with Biodiesel	$6,097,477	$6,997,771	$8,666,362	$7,469,435

BEST WORST

MECO Fuel Switching Strategies

The fuel switching strategies also lower utility capital costs, reflected in the annual revenue requirements for capital metric (Figure 9-29 through Figure 9-32), which depicts the differences in capital costs between the different environmental compliance plans.

The strategies that retire existing units and replace them with new generation have the highest capital costs, higher than installing more than $220 million in AQC equipment.

Figure 9-29. MECO Blazing a Bold Frontier Annual Revenue Requirements of Environmental Compliance Strategies

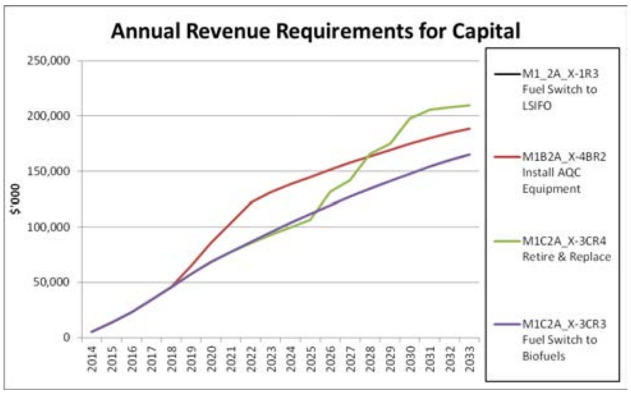


Figure 9-30. MECO Stuck in the Middle Annual Revenue Requirements of Environmental Compliance Strategies

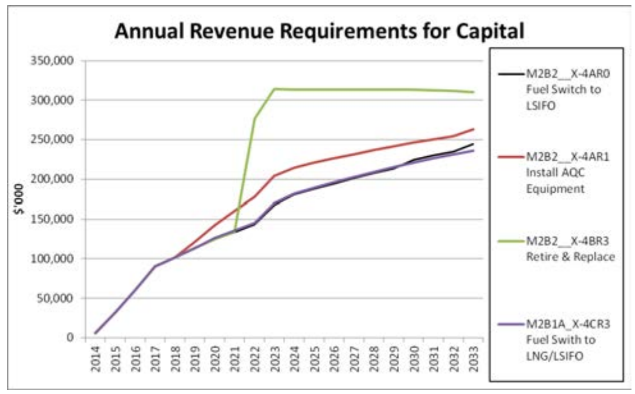


Figure 9-31. MECO No Burning Desire Annual Revenue Requirements of Environmental Compliance Strategies

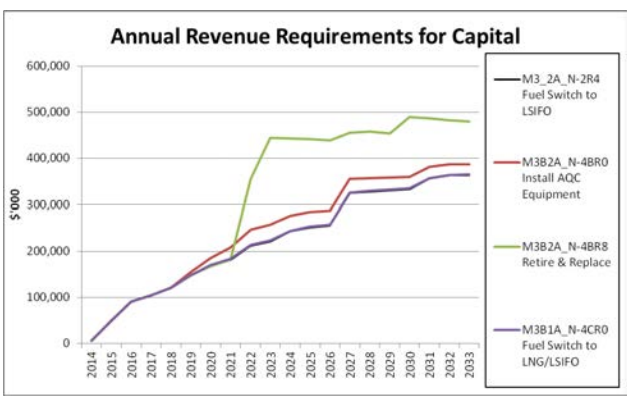
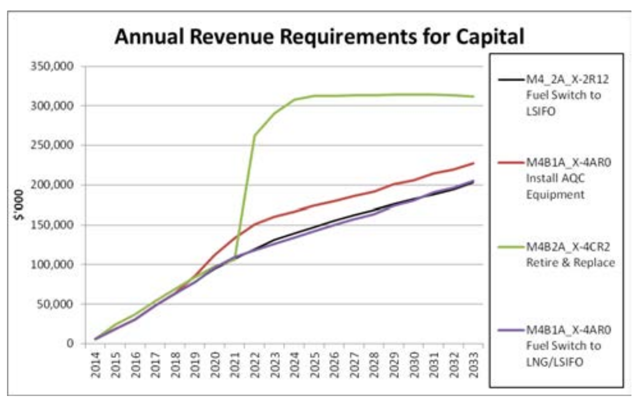


Figure 9-32. MECO Moved by Passion Annual Revenue Requirements of Environmental Compliance Strategies



MECO Resource Plan Costs

Retiring units and replacing them with new generation as well as installing AQC equipment would result in the highest rates in most scenarios except Blazing a Bold Frontier (Figure 9-33 through Figure 9-36). In three of the four scenarios, switching to LSIFO has the lowest rate impact. For Blazing a Bold Frontier, switching existing units to biofuels would result in the lowest rates because biofuels costs decline over time.

Figure 9-33. MECO Blazing a Bold Frontier Estimated Residential and Commercial Rate Impacts for Environmental Compliance Strategies

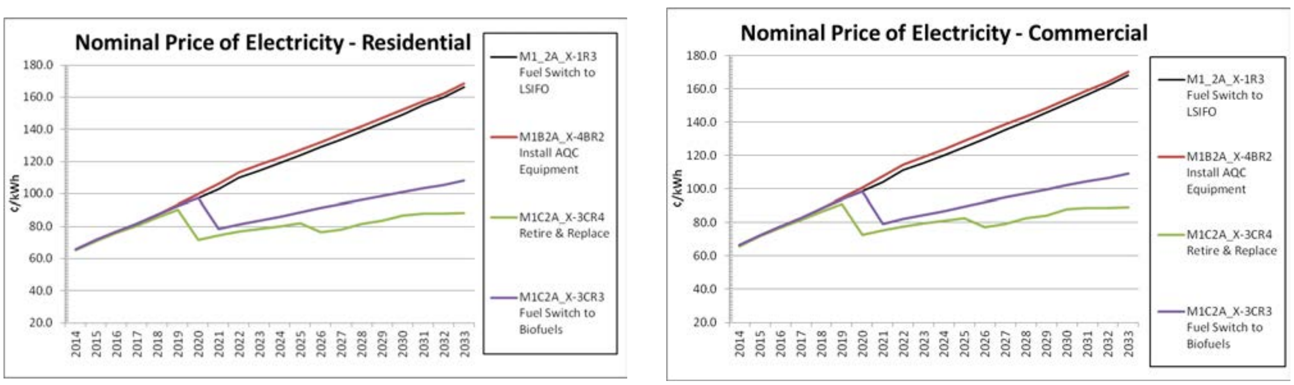


Figure 9-34. MECO Stuck in the Middle Estimated Residential and Commercial Rate Impacts for Environmental Compliance Strategies

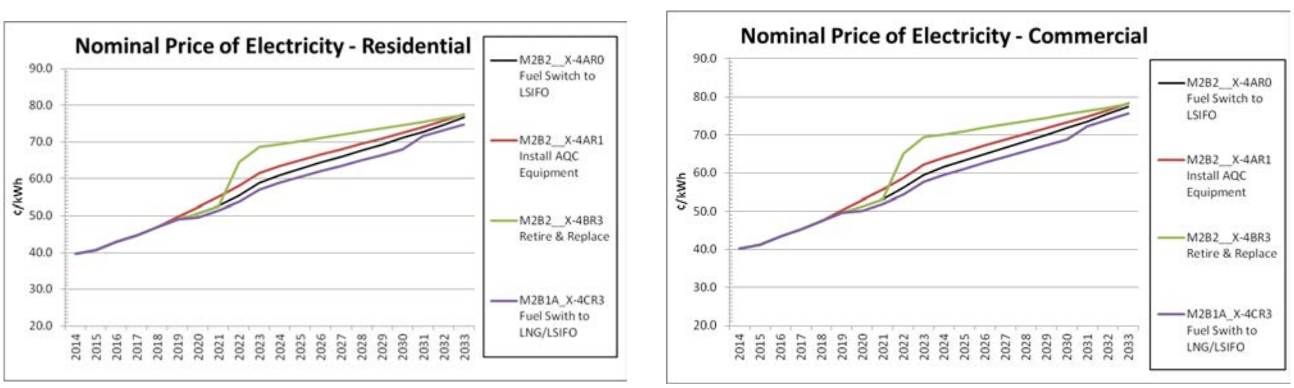


Figure 9-35. MECO No Burning Desire Estimated Residential and Commercial Rate Impacts for Environmental Compliance Strategies

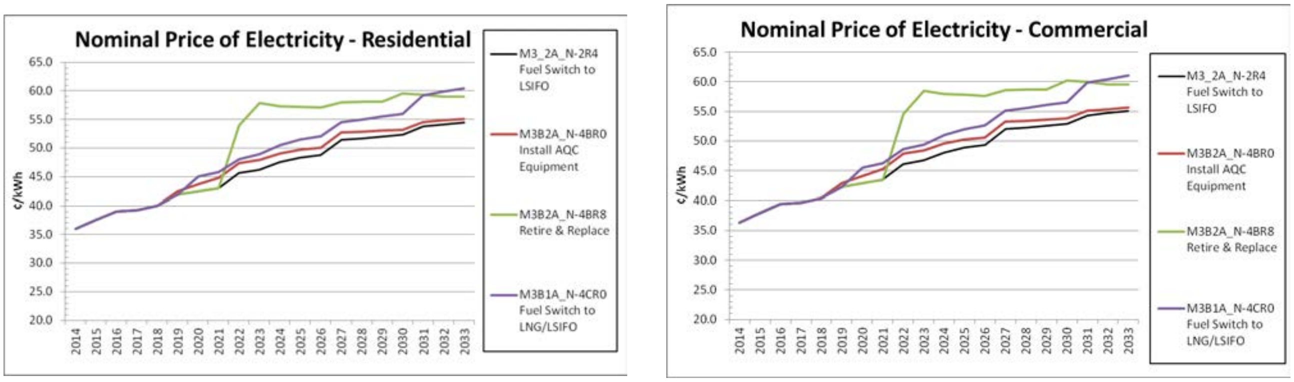
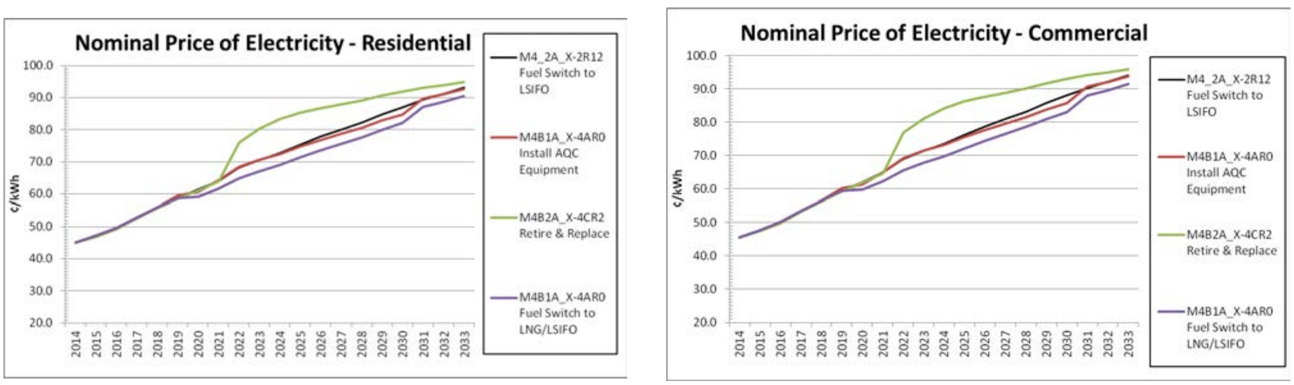


Figure 9-36. MECO Moved by Passion Estimated Residential and Commercial Rate Impacts for Environmental Compliance Strategies



MECO Conclusion

Switching fuels to LSIFO is the most robust, cost-effective strategy.

Chapter 10:
CIP CT-1 Generating Station Analysis

The CIP CT-1 is a biodiesel 110 MW (nominal) simple cycle combustion turbine (CT) generator in the Campbell Industrial Park (CIP). Since operation began in 2009, the unit runs primarily as a peaker. Our analysis focused on finding the plans that affect the most cost-effective fuels for CIP CT-1 for both the short-term and long-term, and on the best use of the unit.

CIP CT-1 Conversion Analysis

The Companies performed seven analysis runs under the Stuck in the Middle scenario to determine the most cost-effective plan for fuel to burn in the CIP CT-1 unit, and how best to operate the unit. These runs addressed the most cost-effective plan in both the short term and in the long term.

All runs were performed over a *planning period* of 20 years, and over a *study period* that includes the 20-year planning period plus the 30-year end effects. All runs are ranked for both the planning period and the study period.

CIP CT-1 Fuel Switch Analysis

We performed three baseline runs operating CIP CT-1 on three different fuels: ultra-low sulfur diesel (ULSD), liquefied natural gas (LNG)[49], and biodiesel. These runs are described in Table 10-1. CIP CT-I Resource Plan (1 of 2) on page 10-7.

We also performed two alternate runs for comparison to the baseline runs. The first alternate run uses ULSD in CIP CT-1 with the addition of 15 MW of PV, and the second alternative run is a sensitivity run for potential low biodiesel prices. These two runs are described in the first two columns of Table 10-2. CIP CT-1 Resource Plan (2 of 2) on page 10-9.

Switch to ULSD (Column Plan Sheet 1)

Of the three baseline plans analyzed for the 20-year planning period, burning ULSD was the least-cost plan. The fuel switch to ULSD would occur in 2016. However, this plan’s ranking over the 30-year study period was not as good as the LNG plan.

Switch to LNG (Plan Sheet Column 2)

Over the length of the 20-year planning period, burning LNG was more expensive than burning ULSD even though the price of LNG is lower than ULSD. This higher cost was due to the additional infrastructure capital for LNG that is only spread over a short portion of the 20-year planning period (13 years).

Over the length of the 30-year study period, however, burning LNG was the least-cost baseline plan.

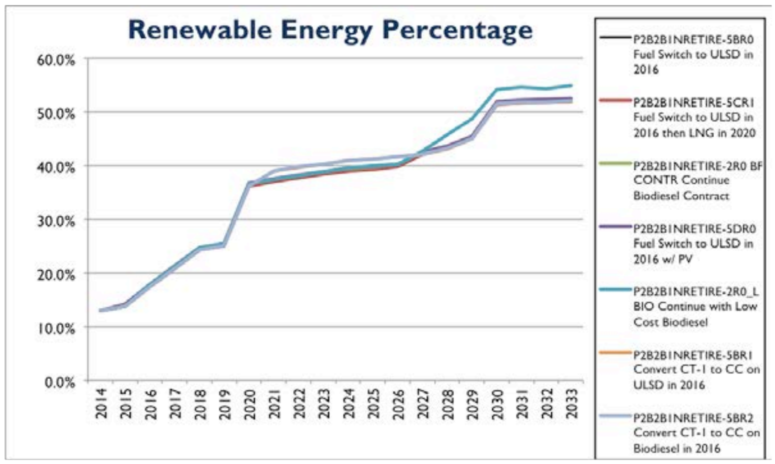
[49] Although the combustion turbine will run on gas in its vapor state (not liquefied gas, LNG), the term LNG is used throughout the study since the fuel pricing is dependent on bring LNG to Hawaii.

Continue Burning Biodiesel (Plan Sheet Column 3)

Over the 20-year planning period as well as the 30-year study period, continuing to burn biodiesel was the most expensive baseline plan, due mainly to the high biodiesel price forecast. For this biodiesel plan, CIP CT-1 was required to consume the minimum limits of the current biodiesel contract.

In addition to fuel cost, we also considered the contributions to the Renewable Energy Percentage (REP) that burning biodiesel enables. With the projected base biodiesel price (in the Stuck in the Middle scenario), CIP CT-1's contribution to the RPS is negligible (see the green line in Figure 10-).

Figure 10-1. CIP CT-1's Renewable Energy Percentage Contribution



The renewable energy contributions of CIP CT-1 increases slightly in a low biodiesel price future (see the blue line in Figure 10-).

Switch to ULSD with PV (Plan Sheet Column 4)

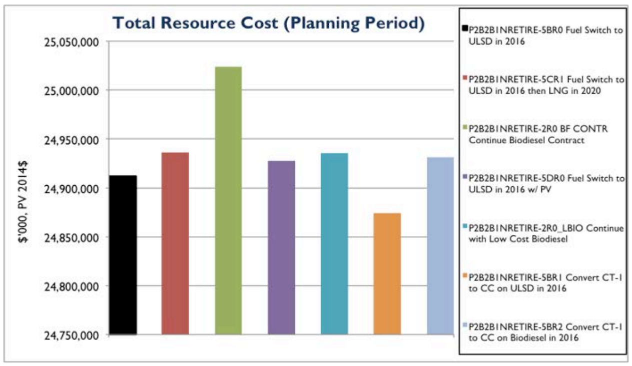
Currently, CIP CT-1 provides a small amount of renewable energy, approximately equivalent to 15 MW of photovoltaics (PV).

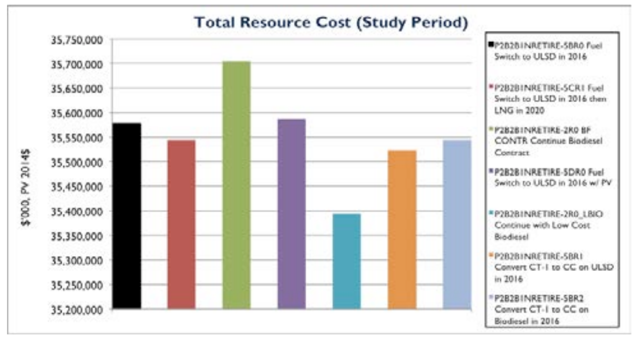
Therefore, we also analyzed an alternate plan using ULSD with an additional 15MW of PV (to get the equivalent renewable energy as when CIP CT-1 burns biodiesel). This alternate plan was then compared to the continued burning of biodiesel at CIP CT-1. With this additional PV, the cost of burning ULSD was still less expensive than burning biodiesel over both the 20-year planning period and the 30-year study period.

Biodiesel Sensitivity (Plan Sheet Column 5)

Because of the uncertainty of future biodiesel prices, we performed a sensitivity run on potential low biodiesel prices. For the 30-year study period, this run produced the lowest cost plan (Figure 10-2, right-hand study period chart). This was not, however, the lowest cost plan over the 20-year planning period (left-hand chart).

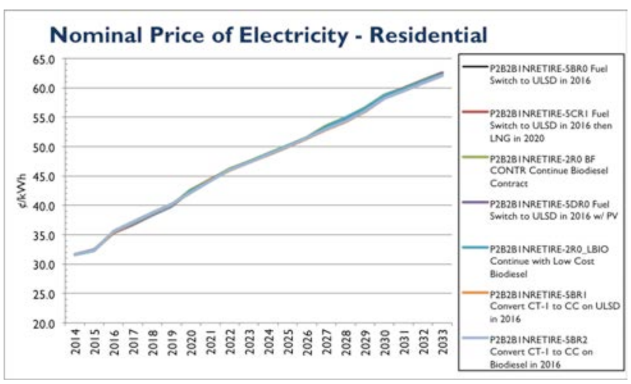
Figure 10-2. Total Resource Cost Comparison: Planning Period versus Study Period

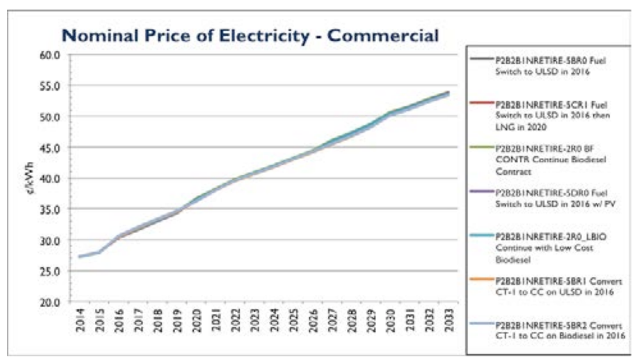




Because CIP CT-1 contributes a small amount of energy to the system when running in simple cycle operation, the impact to rates is negligible (Figure 10-3).

Figure 10-3. Residential and Commercial Rate Comparisons: Planning Period versus Study Period



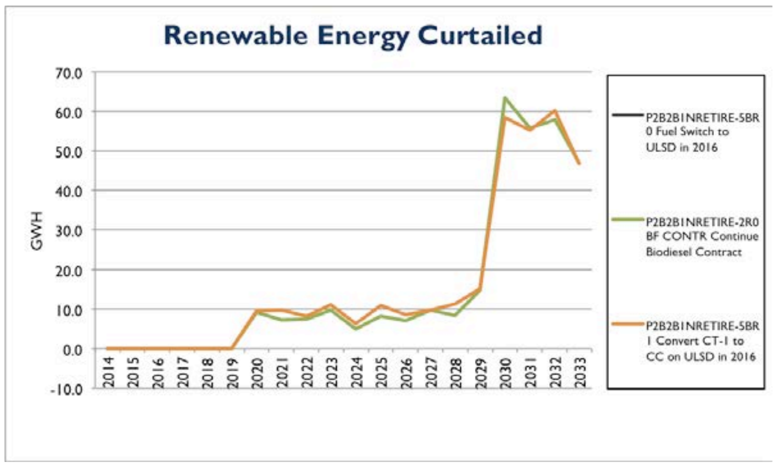


CIP CT-1 Combined Cycle Conversion Analysis

Besides switching fuels burned at CIP CT-1, the Companies also analyzed converting CIP CT-1 to combined cycle (CC) operation using ULSD and biodiesel. Converting CIP CT-1 to combined cycle would add approximately 57 MW of capacity, which would defer the need for adding capacity in 2020 that would be required in the other plans with CIP CT-1 in simple cycle operation.

Converting to combined cycle operation has a small impact on renewable energy curtailment (Figure 10-4).

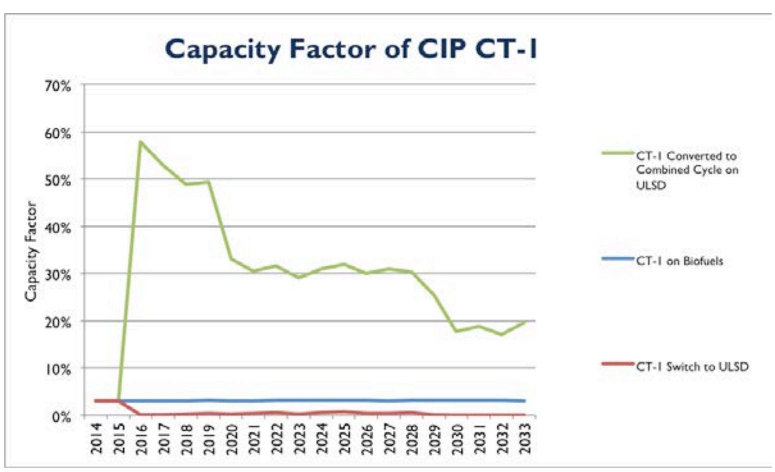
Figure 10-4. Impact of CIP CT-1 Plans on Renewable Energy Curtailment



Combined Cycle and Switch to ULSD (Plan Sheet Column 6)

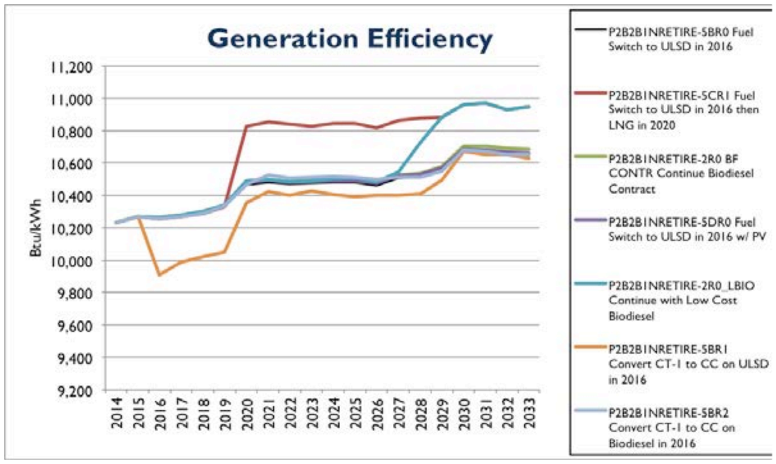
Over both the 20-year planning period and the 30-year study period, converting CIP CT-1 to combined cycle using ULSD results in the lowest cost when compared to the baseline plans. Converting to combined cycle using ULSD also results in higher capacity factors (Figure 10-5) because of the improved efficiency (or lower heat rate) over simple cycle operation.

Figure 10-5. Capacity Factor Comparison of CIP CT-1



This plan — converting CIP CT-1 to combined cycle using ULSD — would also improve the system's heat rate (Figure 10-6). In combined cycle, the top load heat rate would be about 7,800 Btu/kWh.

Figure 10-6. Generation Efficiency (Heat Rate) of CIP CT-1 Options



Combined Cycle and Switch to Biodiesel (Plan Sheet Column 7)

Converting CIP CT-1 to combined cycle and continuing to use biodiesel would result in lower costs than simple cycle operation burning biodiesel (see Figure 10-2. Total Resource Cost Comparison: Planning Period versus Study Period on page 10-4). Over the 20-year planning period, this plan, however, is more costly than switching to ULSD with simple cycle operation.

Conclusion

Over both the 20-year planning period and 30-year study period, switching to the lower-priced ULSD or LNG would be less costly than continuing to burn the higher-priced biodiesel at CIP CT-1 (if biodiesel prices remain high).

Over the 30-year study period, continuing to burn biodiesel at CIP CT-1 would be the lowest cost option compared to the baseline plans should biodiesel prices decline in the future.

Converting CIP CT-1 to combined cycle operation burning either biodiesel or ULSD is less expensive than running simple cycle operation burning the same fuel.

Overall, over both the 20-year planning period and the 30-year study period, converting CIP CT-1 to combined cycle operation burning ULSD results in the lowest cost when compared to the baseline plans.

CIP CT-1 Resource Plans

Table 10-1. CIP CT-1 Resource Plan (1 of 2)

Name	**P2B2B1NRETIRE-5BR0**	**P2B2B1NRETIRE-5CR1**	**P2B2B1NRETIRE-2R0 BF CONTR**
Plan	CIP CT-1 Fuel Switch to ULSD in 2016	CIP CT-1 Fuel Switch to ULSD in 2016 and then to LNG in 2020	Continue Biodiesel Contract
Resources Available	All resources fixed	All resources fixed	All resources fixed
2014	Expanded CIDLC, CIDP, RDLCWH, RDLCAC	Expanded CIDLC, CIDP, RDLCWH, RDLCAC	Expanded CIDLC, CIDP, RDLCWH, RDLCAC
	75% PBFA DSM	75% PBFA DSM	75% PBFA DSM
2015			
2016	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)
	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)
	Fuel switch to diesel (Honolulu 8–9, Waiau 5–8, Kahe 1–6)	Fuel switch to diesel (Honolulu 8–9, Waiau 5–8, Kahe 1–6)	Fuel switch to diesel (Honolulu 8–9, Waiau 5–8, Kahe 1–6)
	Fuel switch to ULSD (CIP CT-1)	Fuel switch to ULSD (CIP CT-1)	Continue biodiesel contract
2017	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)
	Deactivate Waiau 3 (–46MW) & deactivate Waiau 4 (–46MW) or Honolulu 8/9	Deactivate Waiau 3 (–46MW) & deactivate Waiau 4 (–46MW) or Honolulu 8/9	Deactivate Waiau 3 (–46MW) & deactivate Waiau 4 (–46MW) or Honolulu 8/9
2018	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)	Add 20 MW wind (PW01x2)
2019	Deactivate Honolulu 8 (–53 MW) & deactivate Honolulu 9 (–54 MW) or Waiau 3/4	Deactivate Honolulu 8 (–53 MW) & deactivate Honolulu 9 (–54 MW) or Waiau 3/4	Deactivate Honolulu 8 (–53 MW) & deactivate Honolulu 9 (–54 MW) or Waiau 3/4
2020	Add 59MW CC (PC08x1); biodiesel	Add 59MW CC (PC08x1); biodiesel	Add 59MW CC (PC08x1); biodiesel
	Add 200 MW Lanai Wind	Add 200 MW Lanai Wind	Add 200 MW Lanai Wind
		Fuel switch to LNG (CIP CT-1)	
2021			
2022	Fuel switch to ULSD (Honolulu 8–9, Waiau 5–8, Kahe 1–6)	Fuel switch to ULSD (Honolulu 8–9, Waiau 5–8, Kahe 1–6)	Fuel switch to ULSD (Honolulu 8–9, Waiau 5–8, Kahe 1–6)
2023			
2024			
2025			
2026			
2027	Add 25MW (PA01x1); biomass	Add 25MW (PA01x1); biomass	Add 25MW (PA01x1); biomass
2028	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)
2029	Add 30 MW wind (PW01x1)	Add 30 MW wind (PW01x1)	Add 30 MW wind (PW01x1)
	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)

Name	P2B2B1NRETIRE-5BR0	P2B2B1NRETIRE-5CR1	P2B2B1NRETIRE-2R0 BF CONTR
2030	Add 150 MW wind (PW01x5)	Add 150 MW wind (PW01x5)	Add 150 MW wind (PW01x5)
	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)
2031			
2032			
2033			
Strategist Planning Period Total Cost	$22,234,348	$22,176,212	$22,346,532
Strategist Study Period Total Cost	$32,899,064	$32,783,078	$33,026,042
Planning Period Total Cost	$24,911,725	$24,936,482	$25,023,904
Study Period Total Cost	$35,576,441	$35,543,350	$35,703,419
Planning Rank	2	6	7
Study Rank	5	3	7

Table 10-2. CIP CT-1 Resource Plan (2 of 2)

Name	P2B2B1NRETIRE-5DR0	P2B2B1NRETIRE-2R0_LBIO	P2B2B1NRETIRE-5BR1	P2B2B1NRETIRE-5BR2
Plan	CIP CT-1 Fuel Switch to ULSD in 2016 w/ PV providing renewable energy	Continue Biodiesel Contract (Low biodiesel price sensitivity)	Convert CIP CT-1 to Combined Cycle and Fuel Switch to ULSD in 2016	Convert CIP CT-1 to Combined Cycle and Fuel Switch to Biodiesel in 2016
Resources Available	All resources fixed	All resources fixed	All resources fixed	All resources fixed
2014	Expanded CIDLC, CIDP, RDLCWH, RDLCAC	Expanded CIDLC, CIDP, RDLCWH, RDLCAC	Expanded CIDLC, CIDP, RDLCWH, RDLCAC	Expanded CIDLC, CIDP, RDLCWH, RDLCAC
	75% PBFA DSM	75% PBFA DSM	75% PBFA DSM	75% PBFA DSM
2015	Add 15 MW PV (PP03x3)			
2016	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)
	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)
	Fuel switch to diesel (Honolulu 8–9, Waiau 5–8, Kahe 1–6)	Fuel switch to diesel (Honolulu 8–9, Waiau 5–8, Kahe 1–6)	Fuel switch to diesel (Honolulu 8–9, Waiau 5–8, Kahe 1–6)	Fuel switch to diesel (Honolulu 8–9, Waiau 5–8, Kahe 1–6)
	Fuel switch to ULSD (CIP CT-1)	Lower priced biodiesel contract	+57MW convert CIP CT-1 to CC on ULSD (SCC1)	+57MW convert CIP CT-1 to CC on biodiesel (SCC1)
2017	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)
	Deactivate Waiau 3 (–46MW) & deactivate Waiau 4 (–46MW) or Honolulu 8/9	Deactivate Waiau 3 (–46MW) & deactivate Waiau 4 (–46MW) or Honolulu 8/9	Deactivate Waiau 3 (–46MW) & deactivate Waiau 4 (–46MW) or Honolulu 8/9	Deactivate Waiau 3 (–46MW) & deactivate Waiau 4 (–46MW) or Honolulu 8/9
2018	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)
2019	Deactivate H8 (–53MW) & deactivate H9 (–54MW) or Waiau 3/4	Deactivate H8 (–53MW) & deactivate H9 (–54MW) or Waiau 3/4	Deactivate H8 (–53MW) & deactivate H9 (–54MW) or Waiau 3/4	Deactivate H8 (–53MW) & deactivate H9 (–54MW) or Waiau 3/4
2020	Add 59MW CC (PC08x1)-biodiesel	Add 59MW CC (PC08x1)-biodiesel		
	Add 200 MW Lanai Wind	Add 200 MW Lanai Wind	Add 200 MW Lanai Wind	Add 200 MW Lanai Wind
2021			Add 25MW (PA01x1); biomass	Add 25MW (PA01x1); biomass
2022	Fuel switch to ULSD (Honolulu 8–9, Waiau 5–8, Kahe 1–6)	Fuel switch to ULSD (Honolulu 8–9, Waiau 5–8, Kahe 1–6)	Fuel switch to ULSD (Honolulu 8–9, Waiau 5–8, Kahe 1–6)	Fuel switch to ULSD (Honolulu 8–9, Waiau 5–8, Kahe 1–6)
2023				
2024				
2025				
2026				
2027	Add 25MW (PA01x1); biomass	Add 25MW (PA01x1); biomass		
2028	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)
2029	Add 30 MW wind (PW01x1)	Add 30 MW wind (PW01x1)	Add 30 MW wind (PW01x1)	Add 30 MW wind (PW01x1)
	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)

Name	P2B2B1NRETIRE-5DR0	P2B2B1NRETIRE-2R0_LBIO	P2B2B1NRETIRE-5BR1	P2B2B1NRETIRE-5BR2
2030	Add 150 MW wind (PW01x5)	Add 150 MW wind (PW01x5)	Add 150 MW wind (PW01x5)	Add 150 MW wind (PW01x5)
	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)
2031				
2032				
2033				
Strategist PV Planning Period Total Cost [$000]	$22,250,292	$22,258,338	$22,196,516	$22,254,092
Strategist PV Study Period Total Cost [$000]	$32,910,116	$32,716,918	$32,845,660	$32,866,598
PV Planning Period Total Cost [$000]	$24,927,669	$24,935,719	$24,873,891	$24,931,469
PV Study Period Total Cost [$000]	$35,587,493	$35,394,295	$35,523,037	$35,543,975
Planning Rank	3	5	1	4
Study Rank	6	1	2	4

Chapter 11:
Inter-Island and Inter-Utility Connection Analysis

Inter-island and inter-utility connections can directly address the issues of increasing use of renewable energy, lowering the amount and cost of fossil fuel used, and achieving other net benefits. This chapter presents an analysis of connecting the Oahu and Island of Hawaii grids and the Oahu and Maui grids, as well as transmitting energy from wind on Lanai to Oahu.

Interconnecting the Oahu and Island of Hawaii Grids

The Companies analyzed interconnecting the Oahu and Island of Hawaii (Big Island) grids to assess the comparative cost and benefits. *Appendix H: Inter-Island Transmission Costs* details estimated costs. The Companies used the lower ranges of cost estimates to provide a first cut screening analysis of the potential of interconnecting the islands. If the interconnection was not shown to cost effective using the lower ranges then it will not be cost effective with higher costs.

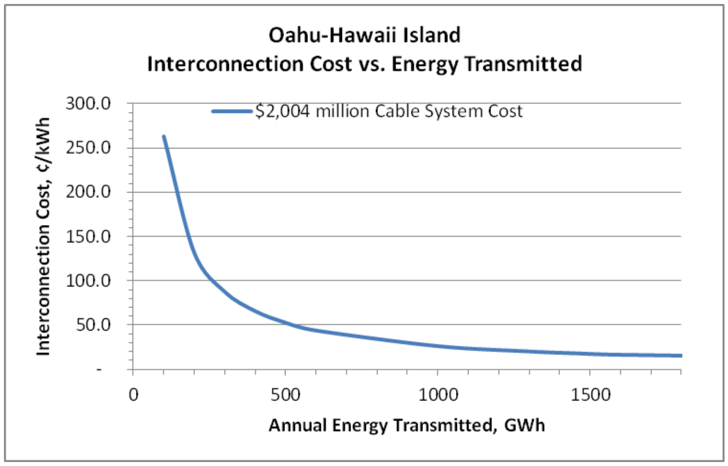
Oahu–Island of Hawaii Interconnection Analysis

To analyze interconnecting Oahu and the Island of Hawaii, the Companies made the following assumptions:

- A total of 400 MW of transmission line capacity installed in two independent 200 MW circuits to provide redundancy in an N-1 contingency. Before losses, each circuit could transmit approximately 1,750 GWh of energy assuming a 100% capacity factor.
- The cost of the transmission system to be $2.004 billion in 2020 based on escalating the low cost estimate of 1.447 million by 3% per year.
- Cable installation to be in 2020.
- An interconnection charge, which is a ¢/kWh cost estimate that a third-party company of the cable system would need to charge for use of the cable (developed from an economic analysis from the cost of the transmission system).
- A third-party would own the inverter-converter stations and the undersea cable and finance the project with an 80/20 debt to equity ratio over 30 years.
- A 5% debt rate and a 20% return on equity.
- Utility ownership of the AC transmission systems, substation, and on-island transmission line.

The Companies calculated the levelized cost to use for the cable system (Figure 11-). This cost sets the minimum difference between the costs of energy on each island that must be overcome before energy is transferred on economic dispatch between grids. This cost differential decreases substantially as the amount of energy transmitted increases.

Figure 11-1. Interconnection Charge Versus Energy Transmitted



Three Interconnection Cases Analyzed

We analyzed and modeled three cases interconnecting Oahu and the Island of Hawaii using the Stuck in the Middle scenario in response to comments from the Independent Entity, Commission Staff. and the Consumer Advocate to establish a “Reference Case”.

Case 1: Hawaiian Electric LNG and HELCO Geothermal

This case analyzed LNG available on Oahu in 2020 and all HELCO units (except for Keahole Combined Cycle) were deactivated and replaced with geothermal resources.

Because geothermal energy costs less to produce than LNG, analysis showed the potential to transmit approximately 150 GWh annually from the HELCO grid to the Hawaiian Electric grid existed assuming no interconnection charges. At this amount of transmitted energy, however, the charges to use the interisland transmission connection would need to be $1.75/kWh lower than the cost to produce energy on Oahu using LNG. Since this is not the case, it is economically unfeasible to transmit this energy.

Case 2: Hawaiian Electric LNG and HELCO LSIFO Switch

This case analyzed LNG available on Oahu in 2020 and all HELCO units (except for Keahole Combined Cycle) switching to Low Sulfur Industrial Fuel Oil (LSIFO) in 2022 to comply with NAAQS regulations.

Because producing energy using LNG is less than producing energy with LSIFO, there is a potential to transmit 500 GWh annually from the Hawaiian Electric grid to the HELCO grid (assuming no interconnection charges). After adding in the interconnection charge of 52¢/kWh, however, increases the cost beyond that of producing energy using LSIFO. As with Case 1, this case is also economically unfeasible.

Case 3: Hawaiian Electric LSD Switch and HELCO Geothermal

This case analyzed Hawaiian Electric units switching to low sulfur diesel (LSD) fuel in 2022 to comply with NAAQS regulations and all HELCO units (except for Keahole Combined Cycle) were deactivated and replaced with geothermal resources.

Approximately 300 GWh of energy could be transmitted from the HELCO grid (assuming no interconnection charge), but as shown in Case 1, this would be economically unfeasible. Beginning in 2022, if Kahe 1 through 4 began cycling, the 208 MW Kalaeloa Power Plant was retired, and 200 MW of additional geothermal power was installed on the Big Island, approximately 1,450 GWh annually could be transferred economically to Oahu with an interconnection charge up to 18¢/kWh. 200 MW of geothermal energy from the Big Island would replace the capacity loss from the Kalaeloa Power Plant retirement on Oahu. Because of the isolation of the geothermal generation, the risk potential of this case would need to be thoroughly evaluated.

Table 11- shows the relative comparisons of Case 3. Resource plan PH2B2B1N-6CR3X shows the two grids with an interconnection which can be compared to resource plan PH2B2B1N-6CR10 which interconnects the grids.

Over the study period, the present value of the total resource cost of generation with the interconnection would be lower by about 5%.

Table 11-1. Comparison Big Island Geothermal Installed Plans to Supply Energy to Oahu Grid Economically

Name	**PH2B2b1N-6Cr3x (No Interconnection)**		**PH2B2b1N-6Cr10 (With Interconnection)**	
Plan	Fuel Switch to ULSD in 2022	HELCO Deactivate Existing Replace with Geothermal	Fuel Switch to ULSD in 2022 Cycle Kahe 1–4 Retire KPLP	HELCO Deactivate Existing Replace with Geothermal Fixed
Notes	Fuel switch applies to all Waiau 5–8 and Kahe 1–6	All Units except Keahole CC are deactivated by Dec 2020 Cycle Hill 5/6, Puna Steam	Fuel switch applies to all Waiau 5–8 and Kahe 1–6 HELCO Geothermal in 2022 provides HECO Capacity Loss from KPLP retirement	All Units except Keahole CC are deactivated by Dec 2020 Cycle Hill 5/6, Puna Steam
Resources Available	None	None	None	None
Interconnection Charge	NA		160 $/MWh	
2014	Expanded CIDLC, CIDP, RDLCWH, RDLCAC		Expanded CIDLC, CIDP, RDLCWH, RDLCAC	

Name	PH2B2b1N-6Cr3x (No Interconnection)		PH2B2b1N-6Cr10 (With Interconnection)	
	75% PBFA DSM	75% PBFA DSM	75% PBFA DSM	75% PBFA DSM
		Hu Honua (21.5MW)		Hu Honua (21.5MW)
2015		Retire Shipman 3 (–6.8 MW)		Retire Shipman 3 (–6.8 MW)
		Retire Shipman 4 (–6.7 MW)		Retire Shipman 4 (–6.7 MW)
2016	Add 20 MW PV (PP03x4)		Add 20 MW PV (PP03x4)	
	Add 60 MW wind (PW01x2)		Add 60 MW wind (PW01x2)	
	Fuel switch to diesel (Honolulu 8–9, Waiau 5–8, Kahe 1–6)		Fuel switch to diesel (Honolulu 8–9, Waiau 5–8, Kahe 1–6)	
2017	Add 60 MW wind (PW01x2)	Add 10MW wind (HW04x1)	Add 60 MW wind (PW01x2)	Add 10MW wind (HW04x1)
	Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW) or Honolulu 8/9		Retire Waiau 3 (–46 MW) Retire Waiau 4 (–46 MW) or Honolulu 8/9	
2018	Add 60 MW wind (PW01x2)		Add 60 MW wind (PW01x2)	
2019	Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW) or Waiau 3/4		Retire Honolulu 8 (–53 MW) Retire Honolulu 9 (–54 MW) or Waiau 3/4	Retire Hill 5 (–13.5 MW)
2020	Add 59MW CC (PC08x1); biofuel	Add 10MW wind (HW04x1)	Add 59MW CC (PC08x1); biofuel	Add 10MW wind (HW04x1)
	Add 200 MW Lanai Wind	Retire Hill 6 (–20 MW) Retire Puna Steam (–15.5 MW) Retire KanoeID 11,15–17 (–9.5 MW) Retire WaimeaD 12–14 (–7.5 MW) Retire KeahoID 21–23 (–7.5 MW) Retire Kanoe CT1 (–10.25 MW) Retire Keaho CT2 (–13.80 MW) Retire Puna CT3 (–19 MW) Retire PanaewD, OuliD, PunaluD, KapuaD (–4 MW)	Add 200 MW Lanai Wind	Retire Hill 6 (–20 MW) Retire Puna Steam (–15.5 MW) Retire KanoeID 11,15–17 (–9.5 MW) Retire WaimeaD 12–14 (–7.5 MW) Retire KeahoID 21–23 (–7.5 MW) Retire Kanoe CT1 (–10.25 MW) Retire Keaho CT2 (–13.80 MW) Retire Puna CT3 (–19 MW) Retire PanaewD, OuliD, PunaluD, KapuaD (–4 MW)
			Inter-island Connection	Inter-island Connection
2021		Add 25MW geothermal (HG01x1)		Add 25MW geothermal (HG01x1)
		Add 75MW new geothermal (HG02x3)		Add 75MW new geothermal (HG02x3)
2022	Fuel switch to ULSD (Waiau 5–8, Kahe 1–6)		Fuel switch to ULSD (Waiau 5–8, Kahe 1–6)	Add 200MW new geothermal (HG02x8)
			Cycle Kahe 1–4	
			Retire KPLP (–208 MW)	
2023				
2024		Add 25MW new geothermal (HG02x1)		Add 25MW new geothermal (HG02x1)

Name	**PH2B2b1N-6Cr3x (No Interconnection)**		**PH2B2b1N-6Cr10 (With Interconnection)**	
2025				
2026				
2027	Add 25MW (PA01x1); biomass		Add 25MW (PA01x1); biomass	
2028			Retire Waiau 5 (– 55MW)	
	Add 20 MW PV (PP03x4)		Add 20 MW PV (PP03x4)	
2029	Add 30 MW wind (PW01x1)		Add 30 MW wind (PW01x1)	
	Add 20 MW PV (PP03x4)		Add 20 MW PV (PP03x4)	
2030	Add 150 MW wind (PW01x5)	Add 10MW wind (HW04x1)	Add 150 MW wind (PW01x5)	Add 10MW wind (HW04x1)
	Add 20 MW PV (PP03x4)		Add 20 MW PV (PP03x4)	
2031		Add 10MW wind (HW04x1)		Add 10MW wind (HW04x1)
2032				
2033			Retire Waiau 6 (– 55MW)	
Planning Period Total Cost	26,513,252		26,270,086	
Study Period Total Cost	39,193,968		37,317,248	
Interconnection Energy				~ 1450 GWH H->P
Planning Rank	2		1	
Study Rank	2		1	

Increased Amount of Renewable Energy

In addition to the potential cost benefits, interconnecting the Oahu and Big Island grids will also increase the total amount of renewable energy used and reduce curtailment. Figure 11-2 shows the higher Renewable Portfolio Standards (RPS) percent from these combined grids. Interconnected grids increase the load available during off-peak hours, and therefore help to reduce the amount of renewable energy that is curtailed (Figure 11-3).

Figure 11-2. Comparison of Renewable Energy Percentage For Combined Oahu and Big Island Grids

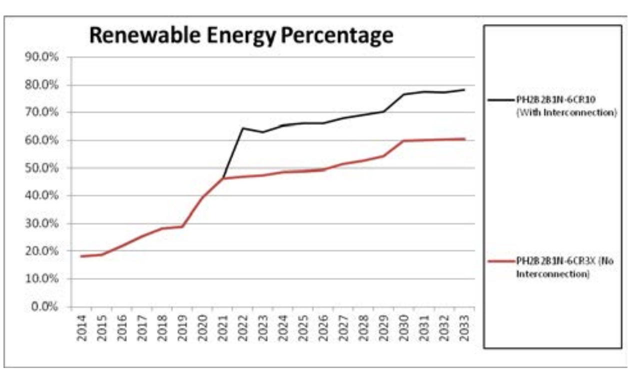
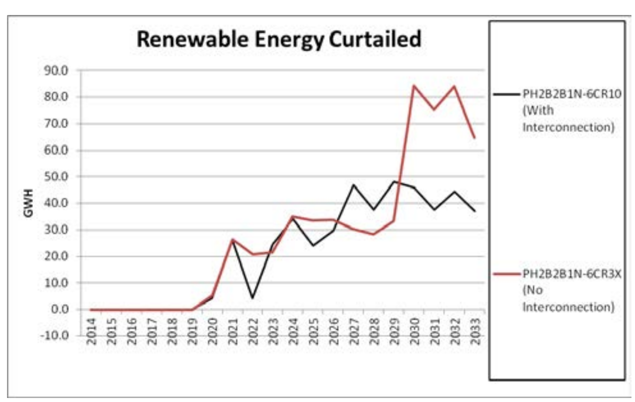


Figure 11-3. Renewable Energy Curtailment Comparison



Reduced Amounts of Fossil Fuel

Interconnection allows the Companies to increase the amount of renewable energy generated and to replace energy generated from imported fossil fuels with renewables (Figure 11-4); thereby reducing the total amount of imported fossil fuels; and it also substantially increases the share of generation from local resources using geothermal energy (Figure 11-5). These factors tend to decrease the price volatility associated with the electricity cost dependent on the cost of oil.

Figure 11-4. Amount of Imported Fossil Fuel with Interconnection

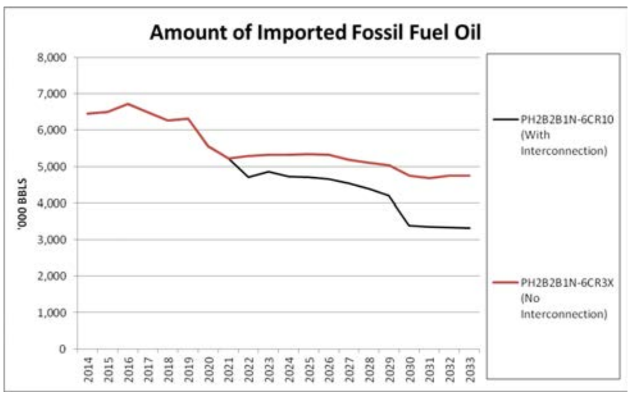
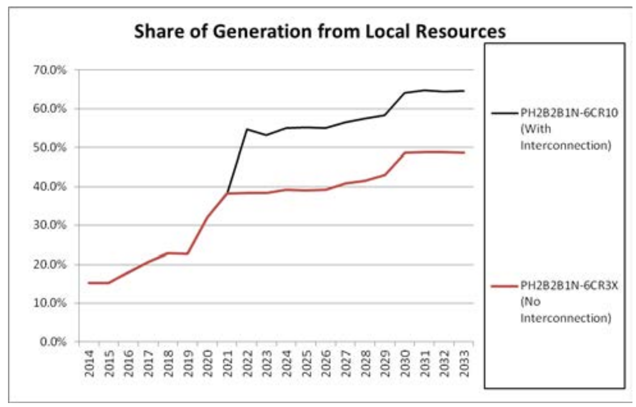


Figure 11-5. Share of Generation from Local Resources with Interconnection

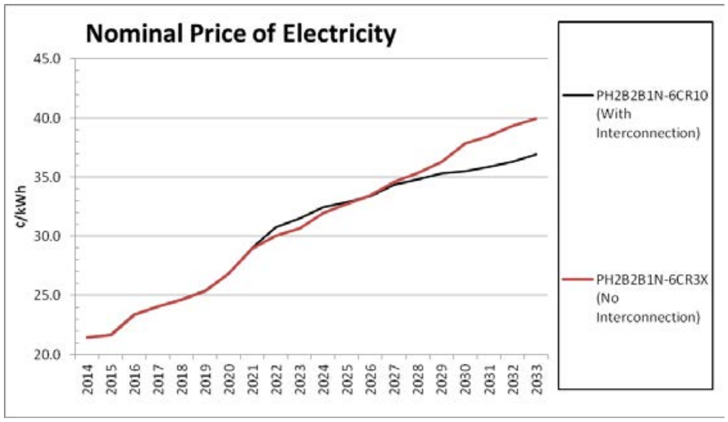


Rate Decrease in the Long Term

To analyze the rate decrease in the long term, simplified rates were used (total revenue requirements for both systems divided by consolidated sales) for generation on the Oahu and Island of Hawaii grids. We could not perform a detailed rate analysis because the allocation of the cost of rate classes across the combined grids is not available.

Figure 11-6 shows the comparison of simplified rates from the interconnected grids, which shows the potential for a rate decrease in the long term.

Figure 11-6. Rate Comparison With and Without Interconnection



Interconnecting the Oahu and Maui Grids

The Companies analyzed interconnecting the Oahu and Maui grids to assess the comparative cost and benefits. *Appendix H: Inter-Island Transmission Costs* details estimated costs. The lower ranges of cost estimates were used to provide a first cut screening analysis of the potential of interconnecting the islands. If the interconnection was not shown to cost effective using the lower ranges then it will not be cost effective with higher costs.

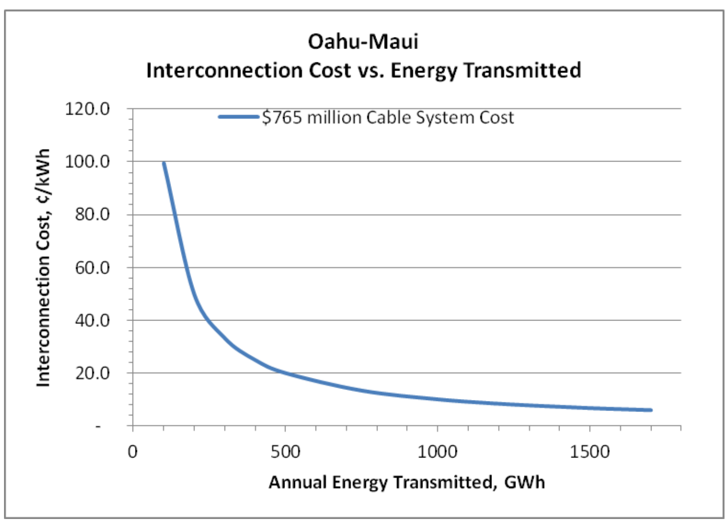
Oahu–Maui Interconnection Analysis

To analyze interconnecting Oahu and Maui, the Companies made the same assumptions as for the Oahu–Island of Hawaii interconnection with two exceptions:

- A total of 200 MW of transmission line capacity installed in one 200 MW circuits without redundancy to withstand an N-1 contingency. Before losses, each circuit could still transmit approximately 1,750 GWh of energy assuming a 100% capacity factor.
- The cost of the transmission system to be $765 million in 2020.

Figure 11-7 depicts the levelized cost for using the cable system. This cost differential decreases substantially as the amount of energy transmitted increases.

Figure 11-7. Interconnection Charge versus Energy Transmitted



Two Interconnection Cases Analyzed

The Companies analyzed and modeled two cases interconnecting Oahu and Maui using the Stuck in the Middle scenario.

Case 1: Hawaiian Electric LNG and Maui LSIFO Switch

This case analyzed Hawaiian Electric units switching to LNG in 2020 and Maui units switching to Low Sulfur Industrial Fuel Oil (LSIFO) in 2022 to comply with NAAQS regulations with 200 MW of Lanai Wind being available in 2020.

The resource plans for this case attempted to replace higher cost energy on Maui with energy from LNG-fueled units on Oahu. With the two grids connected, approximately 190 GWh of energy was transferred from Maui to Oahu and 50 GWh was transferred from Oahu to Maui assuming no interconnection charge. This net-energy transfer from Maui to Oahu indicates that the cost to produce energy on Oahu is more expensive than the cost to produce energy on Maui, even with the availability of LNG on Oahu.

The interconnection does help reduce curtailed energy for the interconnected system by approximately 110 GWh in 2020 but this is offset by interconnection charges of about 39.8¢/kWh. Table 11-2 summarizes the resource plans for Case 1.

Table 11-2. HECO Fuel Switch to LNG, MECO Fuel Switch to LSIFO

Name	**PM2B2B1N-6BR1X (No Interconnection)**		**PM2B2B1N-6BR0 LNG (With Interconnection)**	
Plan	HECO Fuel Switch to LNG in 2020	MECO Year 2022 Fuel Switch to LSIFO	HECO Fuel Switch to LNG in 2020	MECO Year 2022 Fuel Switch to LSIFO
Notes	Fuel switch applies to all Waiau 5–8 and Kahe 1–6	Fuel Switch Allow ICE 17MW Allow Wind, PV, Wave	Fuel switch applies to all Waiau 5–8 and Kahe 1–6	Fuel Switch Allow ICE 17MW Allow Wind, PV, Wave
2014	Expanded CIDLC, CIDP, RDLCWH, RDLCAC	Fast DR only	Expanded CIDLC, CIDP, RDLCWH, RDLCAC	Fast DR only
	75% PBFA DSM	75% PBFA DSM	75% PBFA DSM	75% PBFA DSM
2015		Add 30MW wind (MW04x3)		Add 30MW wind (MW04x3)
2016	Add 20 MW PV (PP03x4)	Add 30MW wind (MW04x3)	Add 20 MW PV (PP03x4)	Add 30MW wind (MW04x3)
	Add 60 MW wind (PW01x2)		Add 60 MW wind (PW01x2)	
2017		Add 30MW wind (MW04x3)		Add 30MW wind (MW04x3)
	Add 60 MW wind (PW01x2)		Add 60 MW wind (PW01x2)	
	Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW) or Honolulu 8/9		Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW) or Honolulu 8/9	
2018	Add 60 MW wind (PW01x2)		Add 60 MW wind (PW01x2)	
2019	Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW) or Waiau 3/4		Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW) or Waiau 3/4	

2020	Add 59MW CC (PC08x1); biofuel		Add 59MW CC (PC08x1); biofuel	
	Add 200 MW Lanai Wind		Add 200 MW Lanai Wind	
			Inter-island Connection	
	Fuel switch to LNG (Waiau 5–8, Kahe 1–6)		Fuel switch to LNG (Waiau 5–8, Kahe 1–6)	
2021				
2022		Fuel switch to LSIFO (Kahului 1–4)		Fuel switch to LSIFO (Kahului 1–4)
2023		ICE biofuel (17 MW)		ICE biofuel (17 MW)
2024				
2025				
2026				
2027	Add 25MW (PA01x1); biomass		Add 25MW (PA01x1); biomass	
2028	Add 20 MW PV (PP03x4)		Add 20 MW PV (PP03x4)	
2029	Add 30 MW wind (PW01x1)		Add 30 MW wind (PW01x1)	
	Add 20 MW PV (PP03x4)		Add 20 MW PV (PP03x4)	
2030	Add 150 MW wind (PW01x5)	Add 5 MW PV (MP03x5)	Add 150 MW wind (PW01x5)	Add 5 MW PV (MP03x5)
	Add 20 MW PV (PP03x4)		Add 20 MW PV (PP03x4)	
2031				
2032				
2033		Add 5 MW PV (MP03x5)		Add 5 MW PV (MP03x5)
Planning Period Total Cost	23,829,954		23,821,372	
Study Period Total Cost	33,994,680		33,919,120	
Interconnection Energy			~50 GWH P–>M	~190 GWH M–>P
Planning Rank	2		1	
Study Rank	2		1	

Case 2: Hawaiian Electric ULSD Switch and Maui LSIFO Switch

Case 2 analyzed Hawaiian Electric units switching to ultra low sulfur diesel fuel (ULSD) and Maui units switching to Low Sulfur Industrial Fuel Oil (LSIFO), both in 2022, to comply with NAAQS regulations, but without the availability of Lanai Wind. In addition, Maui was allowed to add up to 300 MW of wind in 2022 and up to 50 MW of new site geothermal in 2020 (the same year when the cable is installed).

The model added 170 MW of wind in 2020 and transferred approximately 1,100 GWh of energy each year over the planning period. The interconnection charge assessed annually for 1,100 GWh of energy would be about 9.1¢/kWh. When Lanai Wind added 200 MW to Hawaiian Electric in 2020, new wind capacity on Maui was reduced from 170 MW to 20 MW in 2022 because there would then be less need to transfer energy from Maui. Thus, the transfer of energy along the transmission line reflects this. In this situation, approximately 400 GWh of energy was transferred from Maui to Oahu.

Kalaeloa (KPLP) was also considered to be retired in 2022 with and without Lanai Wind. The model performed a firm timing run for Hawaiian Electric to fulfill the capacity need of the system by itself before connecting the Oahu and Maui grids. This run showed that capacity was needed in 2022. After interconnecting Oahu and Maui, 210 MW of wind was added on Maui and approximately 1,350 GWh of energy was transferred from Maui to Oahu. The assessed interconnection charge for this annual energy transfer would be about 7.4¢/kWh. With Lanai Wind in service, approximately 1,100 GWh annually is transferred from Maui to Oahu. The interconnection charge would increase to approximately 9.1¢/kWh.

Besides KPLP being retired, Kahe 1–4 were assumed to cycle instead of being baseload generation. The additional capacity available by cycling these units allows for more energy to transfer across the transmission line from Maui to Oahu: approximately 1,160 GWh of energy transferred annually after an interconnection charge of 7.9¢/kWh. With Lanai Wind in service, the annual transfer of energy falls to approximately 960 GWh after an interconnection charge of 10¢/kWh.

Table 11-3 and Table 11-4 summarize this plan.

Table 11-3. HECO Fuel Switch to ULSD, MECO Fuel Switch to LSIFO, No Lanai Wind

Name	**PM2B2b1N-6Br1 Base (No Interconnection)**		**PM2B2b1N-6Br2 (With Interconnection)**	
Plan	HECO Fuel Switch to ULSD in 2022	MECO Year 2022 Fuel Switch to LSIFO	HECO Fuel Switch to ULSD in 2022	MECO Year 2022 Fuel Switch to LSIFO
Notes	Fuel switch applies to all Waiau 5–8 and Kahe 1–6 Retire KPLP in 2022 No Lanai Wind	Fuel Switch	Fuel switch applies to all Waiau 5–8 and Kahe 1–6 Retire KPLP in 2022 Cycle Kahe 1–4 No Lanai Wind	Fuel Switch Allow up to 300 MW of Wind in 2022
Interconnection Charge	n/a		$79/MWh	
2014	Expanded CIDLC, CIDP, RDLCWH, RDLCAC	Fast DR only	Expanded CIDLC, CIDP, RDLCWH, RDLCAC	Fast DR only
	75% PBFA DSM	75% PBFA DSM	75% PBFA DSM	75% PBFA DSM
2015		Add 30MW wind (MW04x3)		Add 30MW wind (MW04x3)
2016	Add 20 MW PV (PP03x4)	Add 30MW wind (MW04x3)	Add 20 MW PV (PP03x4)	Add 30MW wind (MW04x3)
	Add 60 MW wind (PW01x2)		Add 60 MW wind (PW01x2)	
2017		Add 30MW wind (MW04x3)		Add 30MW wind (MW04x3)
	Add 60 MW wind (PW01x2)		Add 60 MW wind (PW01x2)	
	Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW) or Honolulu 8/9		Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW) or Honolulu 8/9	
2018	Add 60 MW wind (PW01x2)		Add 60 MW wind (PW01x2)	
2019	Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW) or Waiau 3/4		Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW) or Waiau 3/4	
2020	Add 59MW CC (PC08x1); biofuel		Add 59MW CC (PC08x1); biofuel	
			Inter-island Connection	Inter-island Connection
				Add 210MW wind (MW04x21)
2021				
2022	Fuel switch to ULSD (Waiau 5–8, Kahe 1–6)	Fuel switch to LSIFO (Kahului 1–4)	Fuel switch to ULSD (Waiau 5–8, Kahe 1–6)	Fuel switch to LSIFO (Kahului 1–4)
	Retire KPLP (–208MW)		Retire KPLP (–208MW)	
	Add 25MW (PA01x1); biomass		Add 25MW (PA01x1); biomass	
	Add 177MW CC (PC08x3); biofuel		Add 177MW CC (PC08x3); biofuel	
2023		Add 17MW ICE (MS01x1); biofuel		Add 17MW ICE (MS01x1); biofuel
2024				
2025				
2026				
2027				

Name	PM2B2b1N-6Br1 Base (No Interconnection)		PM2B2b1N-6Br2 (With Interconnection)	
2028	Add 20 MW PV (PP03x4)		Add 20 MW PV (PP03x4)	
2029	Add 30 MW wind (PW01x1)		Add 30 MW wind (PW01x1)	
	Add 20 MW PV (PP03x4)		Add 20 MW PV (PP03x4)	
2030	Add 150 MW wind (PW01x5)	Add 5 MW PV (MP03x5)	Add 150 MW wind (PW01x5)	Add 5 MW PV (MP03x5)
	Add 20 MW PV (PP03x4)		Add 20 MW PV (PP03x4)	
2031				
2032				
2033		Add 5 MW PV (MP03x5)		Add 5 MW PV (MP03x5)
Planning Period Total Cost	27,110,320		26,138,918	
Study Period Total Cost	39,931,616		37,821,232	
Interconnection Energy				~1160 GWh M–>P
Planning Rank	2		1	
Study Rank	2		1	

Table 11-4. HECO Fuel Switch to ULSD, MECO Fuel Switch to LSIFO

Name	**PM2B2b1N-6Br1W Base (No Interconnection)**		**PM2B2b1N-6Br2W (With Interconnection)**	
Plan	HECO Fuel Switch to ULSD in 2022	MECO Year 2022 Fuel Switch to LSIFO	HECO Fuel Switch to ULSD in 2022	MECO Year 2022 Fuel Switch to LSIFO
Notes	Fuel switch applies to all Waiau 5–8 and Kahe 1–6 Retire KPLP in 2022	Fuel Switch	Fuel switch applies to all Waiau 5–8 and Kahe 1–6 Retire KPLP in 2022 Cycle Kahe 1–4	Fuel Switch Allow up to 300 MW of Wind in 2022
Interconnection Charge	None		$100/MWh	
2014	Expanded CIDLC, CIDP, RDLCWH, RDLCAC	Fast DR only	Expanded CIDLC, CIDP, RDLCWH, RDLCAC	Fast DR only
	75% PBFA DSM	75% PBFA DSM	75% PBFA DSM	75% PBFA DSM
2015		Add 30MW wind (MW04x3)		Add 30MW wind (MW04x3)
2016	Add 20 MW PV (PP03x4)	Add 30MW wind (MW04x3)	Add 20 MW PV (PP03x4)	Add 30MW wind (MW04x3)
	Add 60 MW wind (PW01x2)		Add 60 MW wind (PW01x2)	
2017		Add 30MW wind (MW04x3)		Add 30MW wind (MW04x3)
	Add 60 MW wind (PW01x2)		Add 60 MW wind (PW01x2)	
	Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW) or Honolulu 8/9		Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW) or Honolulu 8/9	
2018	Add 60 MW wind (PW01x2)		Add 60 MW wind (PW01x2)	
2019	Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW) or Waiau 3/4		Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW) or Waiau 3/4	
2020	Add 59MW CC (PC08x1); biofuel		Add 59MW CC (PC08x1); biofuel	
			Inter-island Connection	Inter-island Connection
	Add 200 MW Lanai Wind		Add 200 MW Lanai Wind	Add 210MW wind (MW04x21)
2021				
2022	Fuel switch to ULSD (Waiau 5–8, Kahe 1–6)	Fuel switch to LSIFO (Kahului 1–4)	Fuel switch to ULSD (Waiau 5–8, Kahe 1–6)	Fuel switch to LSIFO (Kahului 1–4)
	Retire KPLP (–208MW)		Retire KPLP (–208MW)	
	Add 25MW (PA01x1); biomass		Add 25MW (PA01x1); biomass	
	Add 177MW CC (PC08x3); biofuel		Add 177MW CC (PC08x3); biofuel	
2023		Add 17MW ICE (MS01x1); biofuel		Add 17MW ICE (MS01x1); biofuel
2024				
2025				
2026				
2027				
2028	Add 20 MW PV (PP03x4)		Add 20 MW PV (PP03x4)	

Name	PM2B2b1N-6Br1W Base (No Interconnection)		PM2B2b1N-6Br2W (With Interconnection)	
2029	Add 30 MW wind (PW01x1)		Add 30 MW wind (PW01x1)	
	Add 20 MW PV (PP03x4)		Add 20 MW PV (PP03x4)	
2030	Add 150 MW wind (PW01x5)	Add 5 MW PV (MP03x5)	Add 150 MW wind (PW01x5)	
	Add 20 MW PV (PP03x4)		Add 20 MW PV (PP03x4)	Add 5 MW PV (MP03x5)
2031				
2032				
2033		Add 5 MW PV (MP03x5)		Add 5 MW PV (MP03x5)
Planning Period Total Cost	26,733,654		25,795,274	
Study Period Total Cost	39,037,092		36,854,568	
Interconnection Energy				~960 GWh M–>P
Planning Rank	2		1	
Study Rank	2		1	

Evaluating the Two Cases

Considering the present value of the total resource costs, Case 1 has a lower study period cost than the Case 2 situation of Hawaiian Electric ULSD fuel switch with KPLP retired and cycling Kahe 1–4. Case 1, however, does not justify the cost of interconnecting the two grids because the interconnection charge would be 30.7¢/kWh.

Case 2 does demonstrate a least-cost plan, but only if LNG is unavailable and further wind resources are available on Maui. This plan utilizes the cable effectively to drive down the cost of interconnection to 7.9–10¢/kWh, even with Lanai Wind in service. When this appropriate interconnection charge is entered into the model, a significant amount of energy is still transferred economically across the cable.

Increased Amount of Renewable Energy

Interconnecting the Oahu and Maui grids will increase the renewable energy percentage (Figure 11-8), help to reduce curtailed energy (Figure 11-9), and increases energy security, compared to a plan with no interconnection.

Figure 11-8. Renewable Energy Percentage

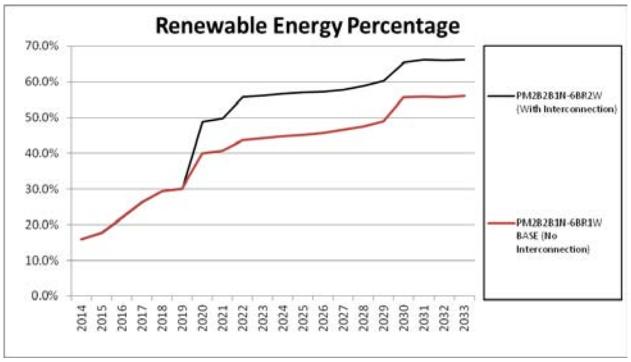
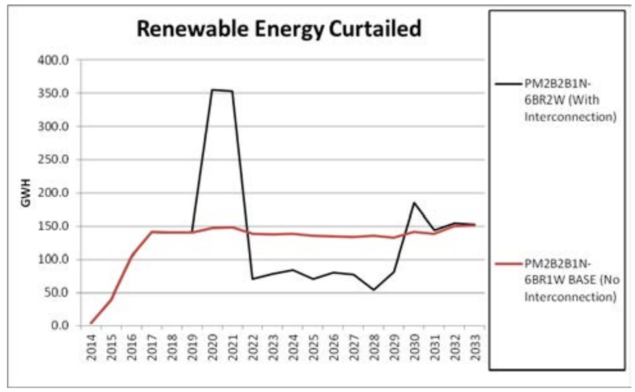


Figure 11-9. Renewable Energy Curtailed



Rate Decrease in the Long Term

To analyze the rate decrease in the long term, simplified rates were used (total revenue requirements for both systems divided by consolidated sales) for generation on the Oahu and Maui grids. The Companies could not perform a detailed rate analysis because the allocation of the cost of rate classes across the combined grids is not available.

This simplified rate shows that a Hawaiian Electric ULSD fuel switch coupled with Lanai Wind in service and additional wind available on Maui can decrease rates by 3.3¢/kWh by 2033.

Figure 11-10. Share of Generation from Local Resources

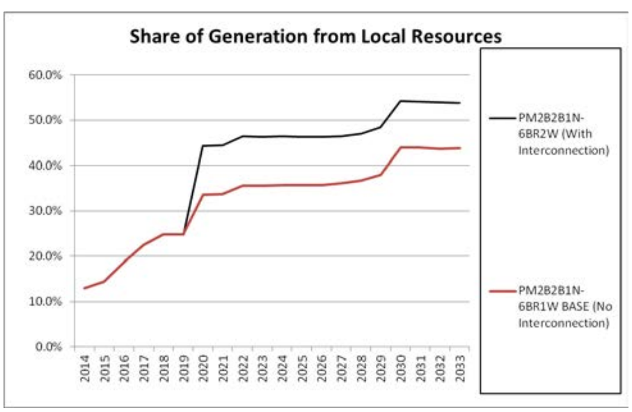
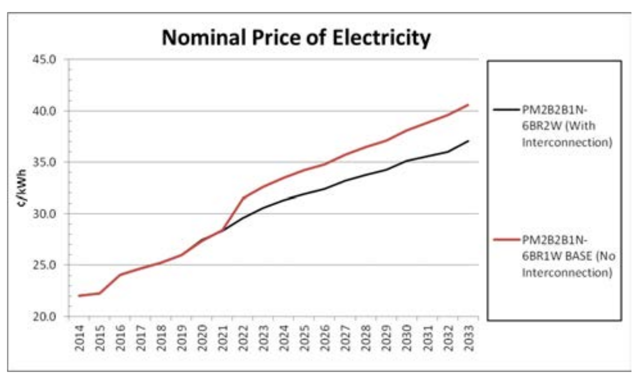


Figure 11-11. Nominal Price of Electricity



Connecting Oahu to Lanai Wind

The Companies analyzed the impact on the Oahu grid from 200 MW of wind generation from Lanai over an inter-island cable. Based on data from *Appendix H: Inter-Island Transmission Costs*, the Companies calculated the levelized interconnection costs as well as the cable price (Table 11-5).

Given the large uncertainty of these costs, it is difficult to determine the cost effectiveness of the Lanai Wind pricing without obtaining a more definite cable price obtainable only through response to an interisland cable RFP.

Table 11-5. Lanai Wind Interconnection Cost Estimates

	Revision 1	Revision 2	
Description	**High**	**High**	**Low**
Lanai Wind Interconnection Capital Cost	528,000,000	689,000,000	472,300,000
Lanai Wind	13.0¢/kWh	13.0¢/kWh	13.0¢/kWh
Interisland Cable & Converter Stations	5.7¢/kWh	8.7¢/kWh	8.0¢/kWh
Oahu Substation	0.4¢/kWh	0.4¢/kWh	0.1¢/kWh
Oahu Transmission	3.0¢/kWh	3.0¢/kWh	0.5¢/kWh
Total Cost (Lanai Wind & Interconnection)	*22.1¢/kWh*	*25.0¢/kWh*	*21.5¢/kWh*

Lanai Wind Resource Plan Model Runs

The model assumes 200 MW of Lanai Wind installed in 2020. Two different levelized energy prices capture the range of possible pricing for the interisland cable between Lanai and Oahu: 22¢/kWh and 25¢/kWh. Models were not run for the Revision 2 Low costs because they were similar to the Revision 1 estimates. We ran model resource plans for all four scenarios with Lanai Wind in service and not in service. In the latter resource plans, other wind and PV resources were added when economical or to meet renewable energy targets based on the data from the unit information forms (UIFs).

Adding Lanai Wind in 2020 for the Blazing a Bold Frontier runs (Table 11-6) increased the total resource cost (TRC) of the resource plan at both cost estimates. On the other hand, adding Lanai Wind in 2020 for the other three scenarios (Table 11-7 through Table 11-9) decreased the TRC of the resource plans at the lower interconnection costs. At the higher interconnection costs, the cost effectiveness of Lanai Wind was marginal.

The construction costs for these renewable resources for Blazing a Bold Frontier were not escalated. The construction costs for Stuck in the Middle, No Burning Desire, and Moved by Passion, however, were escalated at 2–3% per year.

Table 11-6. Lanai Wind Resource Plans: Blazing a Bold Frontier

Name	**P1B2a1xRetire-2r6**	**P1B2a1xRetire-2r6 Lan**	**P1B2a1xRetire-2r6 LanH**
Plan	Retire H8/H9/Waiau 3/Waiau 4, Convert Remaining Existing to Biofuel in 2020, Cycle K1&2	Retire H8/H9/Waiau 3/Waiau 4, Convert Remaining Existing to Biofuel in 2020, Cycle K1&2; Lanai	Retire H8/H9/Waiau 3/Waiau 4, Convert Remaining Existing to Biofuel in 2020, Cycle K1&2; Lanai
Notes	Cycle K1–2 from 2023, Wind30 & PV5 available	Cycle K1–2 from 2023, Wind30 & PV5 available, Lanai Wind 2020	Cycle K1–2 from 2023, Wind30 & PV5 available, Lanai Wind 2020
Resources Available	ICE (17 MW); Biodiesel (PS01): n/a 100 MW SCCT; Biodiesel (PS07): n/a 30 MW Onshore Wind Cl 3 (PW01): 2018 10 MW Onshore Wind Cl 5 (PW03): n/a 10 MW Onshore Wind Cl 7 (PW04): n/a 100 MW Offshore Wind (PW05): n/a 5 MW of 1 MW Tracking PV (PP03): 2020 50 MW Parbolic Trough PV (PP04): n/a 9.6 MW OTEC (POT1): n/a 15 MW Ocean Wave (PV02): n/a	ICE (17 MW); Biodiesel (PS01): n/a 100 MW SCCT; Biodiesel (PS07): n/a 30 MW Onshore Wind Cl 3 (PW01): 2018 10 MW Onshore Wind Cl 5 (PW03): n/a 10 MW Onshore Wind Cl 7 (PW04): n/a 100 MW Offshore Wind (PW05): n/a 5 MW of 1 MW Tracking PV (PP03): 2020 50 MW Parbolic Trough PV (PP04): n/a 9.6 MW OTEC (POT1): n/a 15 MW Ocean Wave (PV02): n/a	ICE (17 MW); Biodiesel (PS01): n/a 100 MW SCCT; Biodiesel (PS07): n/a 30 MW Onshore Wind Cl 3 (PW01): 2018 10 MW Onshore Wind Cl 5 (PW03): n/a 10 MW Onshore Wind Cl 7 (PW04): n/a 100 MW Offshore Wind (PW05): n/a 5 MW of 1 MW Tracking PV (PP03): 2020 50 MW Parbolic Trough PV (PP04): n/a 9.6 MW OTEC (POT1): n/a 15 MW Ocean Wave (PV02): n/a
2014	Continue CIDLC, CIDP, RDLCWH, RDLCAC	Continue CIDLC, CIDP, RDLCWH, RDLCAC	Continue CIDLC, CIDP, RDLCWH, RDLCAC
	75%+25%+10% PBFA DSM	75%+25%+10% PBFA DSM	75%+25%+10% PBFA DSM
2015			
2016			
2017	Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW) or Honolulu 8/9	Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW) or Honolulu 8/9	Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW) or Honolulu 8/9
2018			
2019	Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW) or Waiau 3/4	Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW) or Waiau 3/4	Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW) or Waiau 3/4
2020	Convert all existing units to biofuel (Waiau 5–10 & Kahe 1–6)	Convert all existing units to biofuel (Waiau 5–10 & Kahe 1–6)	Convert all existing units to biofuel (Waiau 5–10 & Kahe 1–6)
		Add 200 MW Lanai Wind	Add 200 MW Lanai Wind
2021			
2022			
2023	Cycle Kahe 1 & 2	Cycle Kahe 1 & 2	Cycle Kahe 1 & 2
2024			
2025			
2026			
2027			
2028			
2029			
2030			
2031			
2032			

Name	P1B2a1xRetire-2r6	P1B2a1xRetire-2r6 Lan	P1B2a1xRetire-2r6 LanH
2033			
Strategist Planning Period Total Cost	26,404,916	26,644,042	26,771,064
Strategist Study Period Total Cost	32,020,054	32,545,570	32,730,858
Planning Period Total Cost	29,082,294	29,321,417	29,448,438
Study Period Total Cost	34,697,431	35,222,947	35,408,235
Planning Rank	1	2	3
Study Rank	1	2	3

Table 11-7. Lanai Wind Resource Plans: Stuck in the Middle

Name	**P2B2a1NRetire-2r0**	**P2B2b1NRetire-2r0**	**P2B2b1NRetire-2r0_LanH**
Plan	No Lanai Wind	With Lanai Wind	With Lanai Wind Revised Cost
Resources Available	59 MW 1on1 LM6000 CC- Biodiesel (PC08): fixed 25MW Banagrass Combustion (PA01): fixed 30 MW Onshore Wind Cl 3 (PW01): 2016 10 MW Onshore Wind Cl 5 (PW03): n/a 10 MW Onshore Wind Cl 7 (PW04): n/a 100 MW Offshore Wind (PW05): n/a 5 MW of 1 MW Tracking PV (PP03): 2015 50 MW Parbolic Trough PV (PP04): n/a 9.6 MW OTEC (POT1): n/a 15 MW Ocean Wave (PV02): n/a	59 MW 1on1 LM6000 CC- Biodiesel (PC08): fixed 25MW Banagrass Combustion (PA01): fixed 30 MW Onshore Wind Cl 3 (PW01): 2016 10 MW Onshore Wind Cl 5 (PW03): n/a 10 MW Onshore Wind Cl 7 (PW04): n/a 100 MW Offshore Wind (PW05): n/a 5 MW of 1 MW Tracking PV (PP03): 2015 50 MW Parbolic Trough PV (PP04): n/a 9.6 MW OTEC (POT1): n/a 15 MW Ocean Wave (PV02): n/a	59 MW 1on1 LM6000 CC- Biodiesel (PC08): fixed 25MW Banagrass Combustion (PA01): fixed 30 MW Onshore Wind Cl 3 (PW01): 2016 10 MW Onshore Wind Cl 5 (PW03): n/a 10 MW Onshore Wind Cl 7 (PW04): n/a 100 MW Offshore Wind (PW05): n/a 5 MW of 1 MW Tracking PV (PP03): 2015 50 MW Parbolic Trough PV (PP04): n/a 9.6 MW OTEC (POT1): n/a 15 MW Ocean Wave (PV02): n/a
2014	Expanded CIDLC, CIDP, RDLCWH, RDLCAC	Expanded CIDLC, CIDP, RDLCWH, RDLCAC	Expanded CIDLC, CIDP, RDLCWH, RDLCAC
	75% PBFA DSM	75% PBFA DSM	75% PBFA DSM
2015	Add 20 MW PV (PP03x4)		
2016	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)
	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)
	Fuel switch to diesel (Honolulu 8–9, Waiau 5–8, Kahe 1–6)	Fuel switch to diesel (Honolulu 8–9, Waiau 5–8, Kahe 1–6)	Fuel switch to diesel (Honolulu 8–9, Waiau 5–8, Kahe 1–6)
2017	Add 20 MW PV (PP03x4)		
	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)
	Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW) or Honolulu 8/9	Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW) or Honolulu 8/9	Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW) or Honolulu 8/9
2018	Add 20 MW PV (PP03x4)		
	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)
2019	Add 60 MW wind (PW01x2)		
	Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW) or Waiau 3/4	Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW) or Waiau 3/4	Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW) or Waiau 3/4
2020	Add 59MW CC (PC08x1); biofuel	Add 59MW CC (PC08x1); biofuel	Add 59MW CC (PC08x1); biofuel
	Add 60 MW wind (PW01x2)	Add 200 MW Lanai Wind	Add 200 MW Lanai Wind
2021			
2022	Fuel switch to ULSD (Honolulu 8–9, Waiau 5–8, Kahe 1–6)	Fuel switch to ULSD (Honolulu 8–9, Waiau 5–8, Kahe 1–6)	Fuel switch to ULSD (Honolulu 8–9, Waiau 5–8, Kahe 1–6)
2023			
2024	Add 60 MW wind (PW01x2)		
2025			
2026			
2027	Add 25MW (PA01x1); biomass	Add 25MW (PA01x1); biomass	Add 25MW (PA01x1); biomass

Name	P2B2a1NRetire-2r0	P2B2b1NRetire-2r0	P2B2b1NRetire-2r0_LanH
2028	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)
2029	Add 60 MW wind (PW01x2)	Add 30 MW wind (PW01x1)	Add 30 MW wind (PW01x1)
	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)
2030	Add 150 MW wind (PW01x5)	Add 150 MW wind (PW01x5)	Add 150 MW wind (PW01x5)
	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)
2031			
2032			
2033			
Strategist Planning Period Total Cost	22,322,938	22,234,112	22,361,132
Strategist Study Period Total Cost	33,236,766	32,899,972	33,085,258
Planning Period Total Cost	25,000,314	24,911,485	25,038,506
Study Period Total Cost	35,914,143	35,577,349	35,762,635
Planning Rank	2	1	3
Study Rank	3	1	2

Table 11-8. Lanai Wind Resource Plans: No Burning Desire

Name	**P3B2a1NRetire-2r0**	**P3B2b1NRetire-2r0**	**P3B2b1NRetire-2r0LanHi**
Plan	Screen Based on P3_2a1NRetire-1r0 w/o Lanai Wind	Screen Based on P3_2a1NRetire-1r0 with Lanai Wind	With Lanai Wind, revised cost
Resources Available	ICE (17 MW); Biodiesel (PS01): Fixed 42 MW SCCT LM6000; Biodiesel (PS06): 2016 100 MW SCCT; Biodiesel (PS07): Fixed 30 MW Onshore Wind Cl 3 (PW01): 2020 10 MW Onshore Wind Cl 5 (PW03): n/a 10 MW Onshore Wind Cl 7 (PW04): n/a 100 MW Offshore Wind (PW05): n/a 5 MW of 1 MW Tracking PV (PP03): 2015 50 MW Parbolic Trough PV (PP04): n/a 9.6 MW OTEC (POT1): n/a 15 MW Ocean Wave (PV02): n/a	ICE (17 MW); Biodiesel (PS01): Fixed 42 MW SCCT LM6000; Biodiesel (PS06): 2016 100 MW SCCT; Biodiesel (PS07): Fixed 30 MW Onshore Wind Cl 3 (PW01): 2020 10 MW Onshore Wind Cl 5 (PW03): n/a 10 MW Onshore Wind Cl 7 (PW04): n/a 100 MW Offshore Wind (PW05): n/a 5 MW of 1 MW Tracking PV (PP03): 2015 50 MW Parbolic Trough PV (PP04): n/a 9.6 MW OTEC (POT1): n/a 15 MW Ocean Wave (PV02): n/a	ICE (17 MW); Biodiesel (PS01): Fixed 42 MW SCCT LM6000; Biodiesel (PS06): 2016 100 MW SCCT; Biodiesel (PS07): Fixed 30 MW Onshore Wind Cl 3 (PW01): 2020 10 MW Onshore Wind Cl 5 (PW03): n/a 10 MW Onshore Wind Cl 7 (PW04): n/a 100 MW Offshore Wind (PW05): n/a 5 MW of 1 MW Tracking PV (PP03): 2015 50 MW Parbolic Trough PV (PP04): n/a 9.6 MW OTEC (POT1): n/a 15 MW Ocean Wave (PV02): n/a
2014	Expanded CIDLC, CIDP, RDLCWH, RDLCAC	Expanded CIDLC, CIDP, RDLCWH, RDLCAC	Expanded CIDLC, CIDP, RDLCWH, RDLCAC
	75% PBFA DSM	75% PBFA DSM	75% PBFA DSM
2015	Add 20 MW PV (PP03x4)		
2016	Add 91MW SCCT (PS07x1); biofuel	Add 91MW SCCT (PS07x1); biofuel	Add 91MW SCCT (PS07x1); biofuel
2017	Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW) or Honolulu 8/9	Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW) or Honolulu 8/9	Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW) or Honolulu 8/9
2018	Add 20 MW PV (PP03x4)		
	Add 91MW SCCT (PS07x1); biofuel	Add 91MW SCCT (PS07x1); biofuel	Add 91MW SCCT (PS07x1); biofuel
2019	Add 17MW ICE (PS01x1); biofuel	Add 17MW ICE (PS01x1); biofuel	Add 17MW ICE (PS01x1); biofuel
	Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW) or Waiau 3/4	Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW) or Waiau 3/4	Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW) or Waiau 3/4
2020		Add 200 MW Lanai Wind	Add 200 MW Lanai Wind
	Add 300 MW wind (PW01x10)	Add 150 MW wind (PW01x5)	Add 150 MW wind (PW01x5)
	Add 182MW SCCT (PS07x2); biofuel	Add 182MW SCCT (PS07x2); biofuel	Add 182MW SCCT (PS07x2); biofuel
2021	Add 150 MW wind (PW01x5)	Add 120 MW wind (PW01x4)	Add 120 MW wind (PW01x4)
2022	Add 120 MW wind (PW01x4)	Add 90 MW wind (PW01x3)	Add 90 MW wind (PW01x3)
2023			
2024	Add 91MW SCCT (PS07x1); biofuel	Add 91MW SCCT (PS07x1); biofuel	Add 91MW SCCT (PS07x1); biofuel
	Add 120 MW wind (PW01x4)	Add 120 MW wind (PW01x4)	Add 120 MW wind (PW01x4)
2025	Add 30 MW wind (PW01x1)	Add 30 MW wind (PW01x1)	Add 30 MW wind (PW01x1)
2026			
2027			
2028			
2029			

Name	P3B2a1NRetire-2r0	P3B2b1NRetire-2r0	P3B2b1NRetire-2r0LanHi
2030			
2031			
2032			
2033	Add 34MW ICE (PS01x2); biofuel	Add 34MW ICE (PS01x2); biofuel	Add 34MW ICE (PS01x2); biofuel
Strategist Planning Period Total Cost	22,935,722	22,853,624	22,980,648
Strategist Study Period Total Cost	33,212,384	32,880,474	33,065,764
Planning Period Total Cost	25,613,099	25,530,999	25,658,020
Study Period Total Cost	35,889,761	35,557,851	35,743,141
Planning Rank	2	1	3
Study Rank	3	1	2

Table 11-9. Lanai Wind Resource Plans: Moved by Passion

Name	**P4B2a1NRetire-2r0 screening**	**P4B2b1NRetire-2r1 screening**	**P4B2b1NRetire-2r1 screen_LanH**
Plan	No Lanai Wind	With Lanai Wind	With Lanai Wind Revised Cost
Resources Available	25MW Banagrass Combust (PA01): 2019 30 MW Onshore Wind Cl 3 (PW01): 2018 10 MW Onshore Wind Cl 5 (PW03): n/a 10 MW Onshore Wind Cl 7 (PW04): n/a 100 MW Offshore Wind (PW05): 2020 5 MW of 1 MW Tracking PV (PP03): 2015 50 MW Parbolic Trough PV (PP04): n/a 9.6 MW OTEC (POT1): n/a 15 MW Ocean Wave (PV02): 2020	25MW Banagrass Combust (PA01): 2019 30 MW Onshore Wind Cl 3 (PW01): 2018 10 MW Onshore Wind Cl 5 (PW03): n/a 10 MW Onshore Wind Cl 7 (PW04): n/a 100 MW Offshore Wind (PW05): 2020 5 MW of 1 MW Tracking PV (PP03): 2015 50 MW Parbolic Trough PV (PP04): n/a 9.6 MW OTEC (POT1): n/a 15 MW Ocean Wave (PV02): 2020	25MW Banagrass Combust (PA01): 2019 30 MW Onshore Wind Cl 3 (PW01): 2018 10 MW Onshore Wind Cl 5 (PW03): n/a 10 MW Onshore Wind Cl 7 (PW04): n/a 100 MW Offshore Wind (PW05): 2020 5 MW of 1 MW Tracking PV (PP03): 2015 50 MW Parbolic Trough PV (PP04): n/a 9.6 MW OTEC (POT1): n/a 15 MW Ocean Wave (PV02): 2020
2014	Expanded CIDLC, CIDP, RDLCWH, RDLCAC	Expanded CIDLC, CIDP, RDLCWH, RDLCAC	Expanded CIDLC, CIDP, RDLCWH, RDLCAC
	75%+25% PBFA DSM	75%+25% PBFA DSM	75%+25% PBFA DSM
2015	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)
2016	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)
2017	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)
	Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW)	Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW)	Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW)
2018	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)
	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)
2019	Add 20 MW PV (PP03x4)		
	Add 60 MW wind (PW01x2)		
	Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW)	Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW)	Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW)
2020	Add 120 MW wind (PW01x4)	Add 200 MW Lanai Wind	Add 200 MW Lanai Wind
2021	Add 20 MW PV (PP03x4)		
2022			
2023			
2024			
2025			
2026			
2027	Add 20 MW PV (PP03x4)		
2028	Add 60 MW wind (PW01x2)	Add 30 MW wind (PW01x1)	Add 30 MW wind (PW01x1)
	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)
2029	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)
	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)
2030	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)
	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)
2031			
2032			

Name	P4B2a1NRetire-2r0 screening	P4B2b1NRetire-2r1 screening	P4B2b1NRetire-2r1 screen_LanH
2033			
Strategist Planning Period Total Cost	23,889,496	23,885,070	24,012,092
Strategist Study Period Total Cost	34,151,112	34,006,408	34,191,696
Planning Period Total Cost	26,621,444	26,617,018	26,744,039
Study Period Total Cost	36,883,061	36,738,357	36,923,645
Planning Rank	2	1	3
Study Rank	2	1	3

Lanai Wind Total Resource Costs

Table 11-10 shows a heat map of how the TRC of the Lanai Wind plans rank in each scenario.

Table 11-10. Heat Map of Total Resource Cost of Lanai Wind Plans by Scenario

Strategies	Blazing a Bold Frontier	Stuck in the Middle	No Burning Desire	Moved by Passion
1. No Lanai Wind	34,697,431	35,914,143	35,889,761	36,883,061
2. Lanai Wind, Low Energy Price Estimate	35,222,947	35,577,349	35,557,851	36,738,357
3. Lanai Wind, High Energy Price Estimate	35,408,235	35,762,635	35,743,141	36,923,645

BEST					WORST

Lanai Wind Electricity Price Comparison

Although the TRC changes for resource plans with and without Lanai Wind, the impact to Oahu residential electricity rates was relatively small for each of the four scenarios (Figure 11-12 through Figure 11-15).

Figure 11-12. Oahu Resource Plans Electricity Price for Lanai Wind: Blazing a Bold Frontier

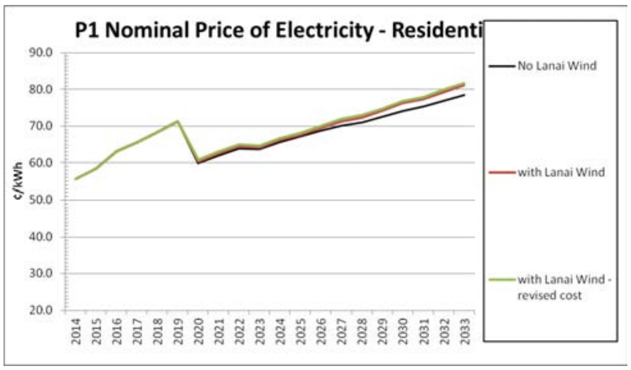


Figure 11-13. Oahu Resource Plans Electricity Price for Lanai Wind: Stuck in the Middle

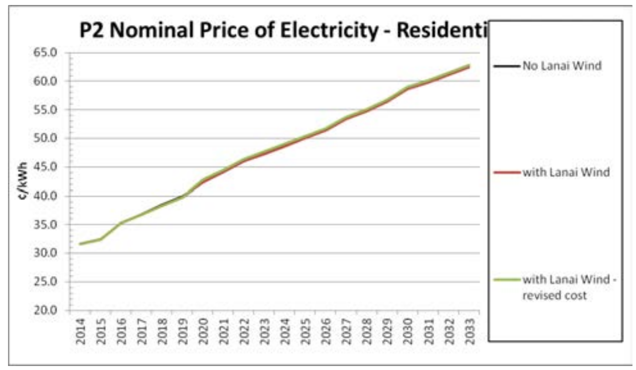


Figure 11-14. Oahu Resource Plans Electricity Price for Lanai Wind: No Burning Desire

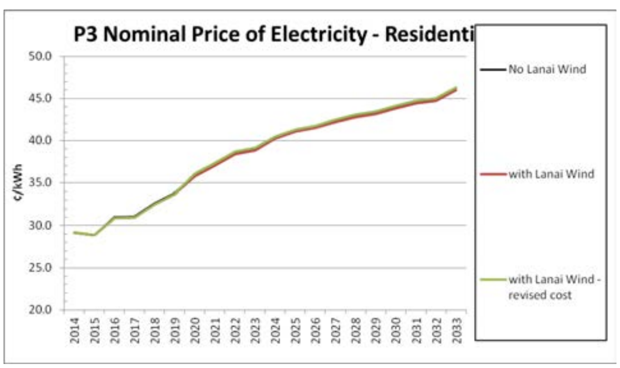
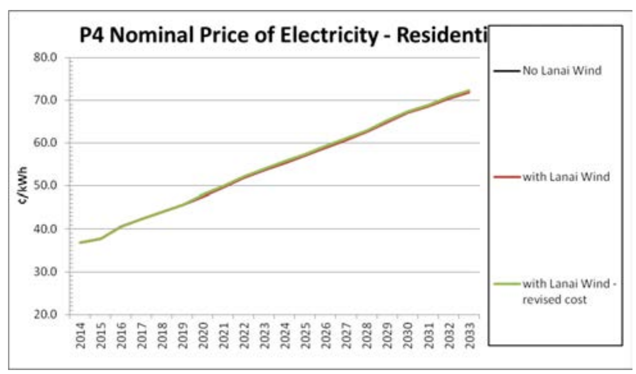


Figure 11-15. Oahu Resource Plans Electricity Price for Lanai Wind: Moved by Passion



Lanai Wind Energy Curtailment Comparison

While the inclusion of Lanai Wind impacted energy curtailment in every scenario, the largest impact was in Blazing a Bold Frontier (Figure 11-16) due to this scenario's declining sales.

In the remaining scenarios (Figure 11-17 through Figure 11-19), Lanai Wind tended to have slightly higher curtailment due to the 200 MW installed energy block.

Figure 11-16. Renewable Energy Curtailment for Lanai Wind: Blazing a Bold Frontier

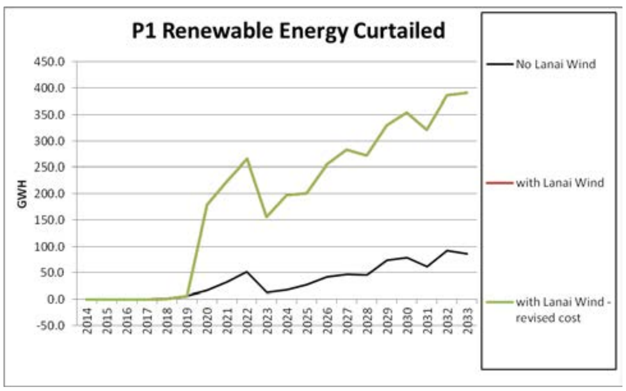


Figure 11-17. Renewable Energy Curtailment for Lanai Wind: Stuck in the Middle

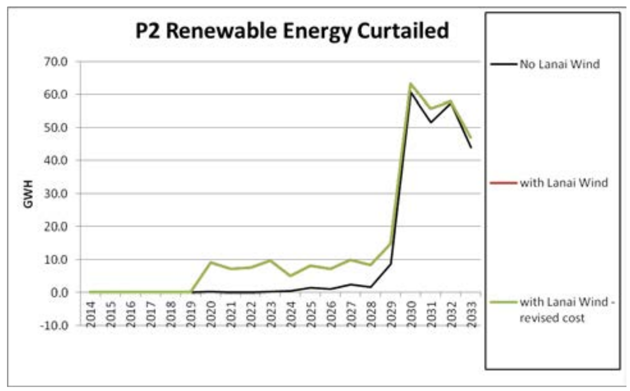


Figure 11-18. Renewable Energy Curtailment for Lanai Wind: No Burning Desire

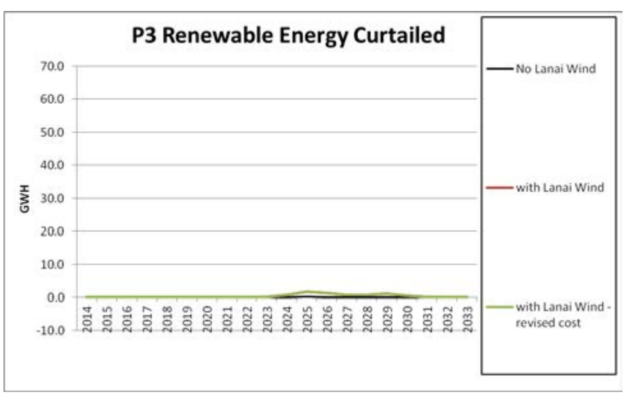
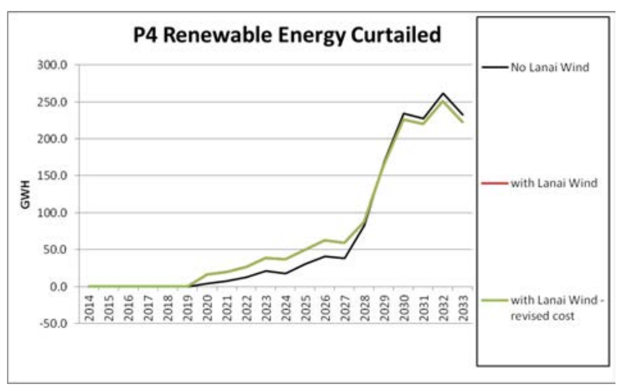


Figure 11-19. Renewable Energy Curtailment for Lanai Wind: Moved by Passion



Chapter 12:
Smart Grid Implementation Analysis

Our comprehensive analysis into implementing Smart Grid technologies is designed to lead the Companies to adopt and utilize a Smart Grid, which also includes implementing advanced metering systems. The Companies are taking a measured approach toward implementation through the following key steps:

- Comprehensive planning
- Technology installations
- Business case analysis
- Customer value

Our overall goal is to enable more efficient and reliable grid operations, enhance customer service, increase energy efficiencies, and enable smooth interconnection with distributed renewable energy resources.

What Is a Smart Grid?

A Smart Grid is an electrical grid that uses intelligent electrical devices, two-way communications technology, and control systems throughout the grid to gather, display, analyze, provide, and act on information in a timely manner. Such a modern grid will deliver greater value to our customers. This broad definition encompasses all electrical grid components including generation, transmission, distribution, and customer equipment with their associated communication and control systems.

Until recently, much of the analysis and grid modernization has focused on new systems that were needed to integrate large, as-available generation (primarily wind power) on all three islands. These systems included Battery Energy Storage Systems (BESS), Automatic Generation Control (AGC) modifications, generator control changes, and syncrophasor measurement devices. While the Companies are still learning about and adapting to the large variable generation on their systems, in more recent years, we have seen the large increase in distributed generation. At the same time, we anticipate increased electrification of transportation in the future, and high energy costs continue to be a concern. As such, the Companies' Smart Grid efforts will focus on distribution and customer applications that create modern grids that are:

- **Efficient:** Enabling more efficient operation and management of the grid and all its energy resources, while improving its reliability and resiliency.
- **Informative:** Providing information to the customer, system operators, and planners to improve decision-making and control that customers have on the use of energy and that the utilities have on the delivery of energy to our customers.
- **Enabling:** Providing information and technology that enables customers to utilize the grid in new ways (DG, EV, and others) in a cost effective and reliable manner and to have more options in the payment and pricing for the energy they use.

The Companies' vision is to transform the existing grid into a "smarter", more efficient, more reliable grid that integrates more renewable energy through the use of various technologies and capabilities and provides more information and options to customers with the overall goal of reducing costs and improving service to our customers.

Implementing technologies such as Distribution Automation (DA), Voltage-VAR Optimization (VVO), fault current indicators (FCI), and demand response (DR) programs that provide offline reserve will make the grid more efficient and reliable, thereby enhancing our services quality.

By providing an Advanced Metering Infrastructure (AMI), customers can have a smart meter that enables two-way communications with utility systems and provides more timely usage information. This information enables customers to better understand their energy use and adjust their usage before receiving their monthly bill. AMI systems can also enable more choices for managing their usage through various pricing and payment programs: Time of Use (TOU), Critical Peak Pricing (CPP), Critical Peak Rebates (CPR), Pre-Pay Metering, and Electric Vehicle (EV) charging. AMI systems can also provide the utility with outage and voltage information that will enable it to respond to outages quicker, operate the grid more efficiently and reduce energy consumption by our customers.

Technologies such as smart inverters for photovoltaic (PV) and other distributed energy systems connected to and communicating with the utility will help to manage and integrate higher penetrations of PV, EV, and other distributed resources onto the grid.

The Smart Grid requires a telecom infrastructure between all of the Smart Grid components and the business and operations management systems that support the Smart Grid functions. The Companies' telecom infrastructure enables and supports Smart Grid communications and all of the other business and operations functions that require communications. The Telecom Action Plan is provided for HECCO Chapter 20, for HELCO in Chapter 21, and for MECO in Chapter 22.

Smart Grid Capabilities

The Smart Grid can provide many different capabilities. The Companies have identified an initial set of 13 capabilities that promise to provide the most value to our customers.

1. Provide customers with relevant and timely information that will allow them to make informed decisions on energy usage.
2. Provide customer service representatives (CSRs) with ready access to interval meter and usage information to improve communications with customers.
3. Provide options to customers to help them manage the cost and nature of their electricity consumption. These options include different tariffs and rate schedules, new programs (such as pre-pay), new uses (such as EVs), and remote operations (such as remote connects and reconnects to provide more immediate service connections).
4. Provide historical data and information to planners and asset managers. This would include feeder and customer level voltages, loading, status, asset information (transformers, cap banks, LTCs, batteries), power quality information, and distributed generation information to reduce uncertainty and enable proactive maintenance practices.
5. Provide system operators with information and visualization tools to provide relevant and timely information at the customer (end-use) and distribution levels of the grid for more proactive and efficient responses to reliability and power quality issues.

6. Provide additional remote monitoring and control of distribution equipment (Supervisory Control And Data Acquisition – SCADA) to improve efficiency of grid operations and improve system reliability.
7. Provide system operators with information and control of distributed energy resources within the home (PV, EV, water heaters, community storage) to enable the grid to be operated more efficiently and allow renewable energy to be better utilized.
8. Provide automatic notification and identification of fault locations to enable more timely and efficient responses to outages.
9. Implement feeder automation to improve efficiency and outage response (Volt-VAR Optimization—VVO and fault location isolation and system restoration—FLISR).
10. Provide CSRs and system operators with individual, on-demand meter reads and status to confirm billing information and identify service outages (including pocket outages) enabling more timely and efficient responses to outages.
11. Enable data sharing and coordination with relevant external network operation centers (such as EV manufacturers, EV charging networks, wind and solar forecasters) to improve reliability and efficiency of grid operations and enable greater utilization of renewable energy resources.
12. Develop autonomous distributed control systems (Micro-DMS, Advanced PV inverters, distributed battery systems) to improve reliability and efficiency of grid operations and enable greater utilization of renewable energy resources.
13. Enable improved Asset Management of the Companies grid assets by remotely monitoring the status and health of the utility assets along the power lines and within the Company facilities, to increase proactive preventive maintenance and reduce reactionary, corrective maintenance.

These capabilities are enabled through the implementation of Smart Grid technologies (such as AMI and SCADA), more capable distributed energy resources, and their supporting telecommunication and information technologies.

The cost of these capabilities, however, must be weighed against the benefits.

Implementing the Smart Grid

While still underway, the analysis points to the Companies adopting and utilizing a Smart Grid, which also includes implementing advanced metering systems.

Smart Grid directly affects a broad cross-section of the Companies' resources and infrastructure. While its implementation requires a significant investment, Smart Grid has the potential to deliver significant benefits to the Companies and its customers. Because of the comprehensive nature of Smart Grid, the Companies are taking a measured approach towards implementation through the following key steps:

- Comprehensive planning
- Technology installations
- Business case analysis
- Customer value

Comprehensive Planning and Technology Installations

The Companies have taken a conservative approach to Smart Grid, recognizing both its significant benefit as well as its significant cost to customers. This approach entails learning from investments that other utilities have made, reviewing a number of utility Smart Grid business cases, and participating in a number of pilot programs with various partners to develop and assess new technologies. The Companies' plan is to adopt proven methodologies, protocols, and technologies that have demonstrated benefits in reducing the risk of investing in these new technologies. To the extent possible, the companies will seek technologies that adhere to industry standards (including cyber security) and provide interoperability amongst products and systems.

The Companies' Smart Grid work started in 2006 with a smart meter pilot project on Oahu and has expanded to encompass applications that more broadly leverage the capabilities of Advanced Meter Infrastructure (AMI) networks in general (such as the wireless transmission of events from faulted circuit indicators).

During the past six years, the Companies engaged the Smart Grid community and closely watched and evaluated technologies as they became available and matured. The Companies are already active participants in many Smart Grid demonstration programs that include the following organizations:

- Hawaii Natural Energy Institute (HNEI)
- Electric Power Research Institute (EPRI)
- New Energy Development Organization (NEDO)
- U.S. Department of Energy (US-DOE)

An initial Smart Grid roadmap was prepared in 2010 and was filed with the Commission in response to CA-IR-271 in Docket 2010-0080.[50] Since then, the Companies have been working on Smart Grid foundational elements, pilots, and technology demonstration projects, updating our Smart Grid roadmaps with a focus on identifying the Smart Grid drivers, capabilities, and components that can improve the experience of customers. (These capabilities are described in Costs and Benefits of Smart Grids, page 12-8.) The Companies expect to finish a smart meter deployment plan in 2013.

As part of its Smart Grid efforts, the Companies are committed to the implementation AMI, CVR and Pre-Pay projects and programs. Initially, a limited number of advanced grid technology components will be installed to obtain and assess some of the high value benefits expected from smart systems. These initial installations establish a solid foundation for future expansion, demonstrate customer benefits, allow course corrections and move towards achieving a future Smart Grid vision.

[50] Docket No. 2010-0080, Hawaiian Electric Company's Hawaiian Electric response to CA-IR-271 filed May 12, 2011.

Business Case Analysis

Hawaiian Electric filed for approval of an AMI project in 2008 and provided a benefit-cost analysis of the quantifiable benefits (Table 12-) that included labor and equipment efficiency for meter reading and field services, theft savings, and accuracy of meter savings. The benefit-cost analysis uses estimated costs and quantifiable benefits for the AMI projects for 2010 through 2029. The Companies included the benefit-cost evaluation in its response to PUC-IR-22 in Docket 2008-0303.

Table 12-1: AMI Benefit-Cost Evaluation

Utility	Benefit-Cost Ratio Discounted*	Benefit-Cost Ratio Not Discounted
HECO	0.94	1.42
HELCO	0.71	1.00
MECO	0.81	1.17

**The discount rate is 8.62%*

Savings from AMI-enabled DR and improved outage management were not included because they could not be readily quantified. The 2008 AMI benefit-cost analysis also did not analyze functions that could be enabled by AMI such as Pre-Pay Programs and Conservation Voltage Reduction (CVR), nor the non-financial benefits that are discussed in Costs and Benefits of Smart Grids (page 12-8).

Hawaiian Electric plans to update its 2008 AMI business case with current market data and utility experiences, including the gap between projected and realized AMI system benefits. The Companies will also be able to develop more accurate cost estimates for the integration of its new CIS with its future AMI systems and include an analysis of both CVR projects and Pre-Pay Programs.

In advance of the Companies' updated business cases, see "Exhibit I: Benefit-Cost Business Case Analyses" (page 12-20) for several examples of business case analyses that were conducted by the Edison Electric Institute and Electric Power Research Institute and other United States utilities.

Costs and Benefits of Smart Grids

The costs and benefits of Smart Grid systems include both tangible and intangible benefits. The Companies have estimated costs and benefits for individual Smart Grid programs (such as AMI[51] as noted above) and DR through their respective project applications. With DR, the projected benefits far exceed the estimated program costs, primarily due to capacity deferral. With AMI, the tangible quantifiable benefits were comparable to the costs; however, not all tangible benefits could be quantified.

Across the nation, there are many examples of business case analyses that were developed for utility Smart Grid projects, as well as by organizations such as the Electric Power Research Institute (EPRI), the Edison Electric Institute (EEI), the Utilities Telecom Council (UTC), as well as numerous consultants. (See "Exhibit I: Benefit-Cost Business Case Analyses" (page 12-20) for several examples.)

In many of these cases, utility Smart Grid projects show net benefits. The Companies' analysis of the cost and benefits of these business cases will help to increase understanding all the benefits and costs of Smart Grid projects and better inform our Companies' business case development. That said, it is essential to develop business cases for each Smart Grid project, or integrated set of projects, specific to Hawaii systems and customers. Developing accurate assumptions before having Hawaii-specific data is difficult. Data from the Companies' pilots, demonstrations, and targeted deployment projects will help validate some of the benefits derived from implementing Smart Grid.

The Companies' Smart Grid goals are implementing targeted deployments focused on increasing the ability to accommodate increased levels of renewable energy and on improving the efficient utilization of electricity (energy efficiency) all the way through to customer end-uses, while ensuring grid reliability and service quality are maintained or improved. The pace of Smart Grid implementation will depend on the business case for each Smart Grid application, availability of commercially viable solutions, and availability of resources across the Companies.

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[51] The benefit and costs for full AMI deployments at Hawaiian Electric, HELCO, and MECO are provided in Exhibit 19 of the Companies' 2008 AMI Application (Docket 2008-0303). The Companies provide Benefit-Cost Ratios for full AMI deployments at Hawaiian Electric, HELCO, and MECO in response to PUC-IR-22 (Docket 2008-0303).

A More Efficient and Reliable Electrical Grid

Implementing Smart Grid requires a robust, hierarchical communications network connecting our control centers with equipment at distribution substations, sensors (such as line-mounted fault indicators), control devices (such as automated switches) on distribution feeders, and devices at customer premises (such as AMI meters and load control switches). The network of sensors and control devices will improve visibility, provide semi-automatic or fully automatic decision making, and remotely monitor and control the utility's assets (mitigating the need to roll trucks and improving customer service). Although largely invisible to customers, Smart Grid activities, at the system level, play a key role in helping the Companies operate the electric grids efficiently and reliably.

The Companies' Construction and Maintenance Department has an active Fault Current Indicator (FCI) installation program that is targeting critical transmission and distribution circuits. Communication-enabled FCIs and outage events (transmitted by AMI meter systems) will enable a system operator to quickly locate, isolate, and re-energize circuits.

Smart Grid technologies take advantage of the communication capabilities of modern FCIs and AMI meters by integrating these devices into other systems such as Outage Management Systems (OMS) and Fault Location Isolation and System Restoration (FLISR) systems. Both of these systems synthesize SCADA, FCI, and AMI meter data with information from a geographic information system (GIS) and circuit connectivity to manage and improve response and restoration times. These integrated systems can then identify fault locations and outages and offer system operators with options to re-route power to reduce the impact and duration of outages and reduce the time spent by field crews to locate the faulted section of the circuit.

AMI meter systems can also help system operators identify "pocket outages" where certain customers may be without power when one or more circuits are restored. Currently, operators identify pocket outages manually by either calling customers to determine if power has been restored or taking customer calls reporting continued power outages.

To further increase system reliability and efficiency, the Companies are implementing more remote switching capabilities. Smart Grid implementations combine modern FCIs and remote switching with new distribution management systems (DMS) capabilities. In turn, the DMS leverages data from related systems (such as OMS and AMI) to provide operators with greater situational awareness and enable them to respond to events more efficiently.

This increased visibility enables system operators to remotely control the system, reducing the number of field crews dispatched to trouble sites and the associated time resolving the outage. Field crews, of course, are still necessary to fix faults, but the Companies response can be quicker and more efficient, thus reducing costs and improving reliability.

AMI meters at customer premises reduce operational costs (improving efficiency) associated with meter reading, service connects and reconnects, and move-in/move-out operations. AMI meters also reduce electricity theft and meter tampering, saving additional money and increasing customer equity. Our estimated energy theft benefits were included in the 2008 AMI Application: Docket 2008-0303 (attached as Exhibit II: Energy Theft Benefits, page 12-26).

Smart Grid enables line voltages to be fine-tuned, reducing system losses. Such techniques help ensure that reliable power is delivered within tariff requirements. Because there is currently no power quality information at customer premises, the Companies oftentimes need to be conservative to the high end of the allowable service voltages to mitigate potential voltage sags at the farthest premise on the distribution circuit. A standard feature of AMI meters is multiple measures of power quality: high, low, and average voltages; instantaneous voltage; and the number of momentary outages. This AMI-meter feature enables technicians to proactively react to potential problems or opportunities on the distribution system rather than reacting to customer complaints.

Utilities across the country have implemented Voltage-VAR Optimization (VVO), and more specifically Conservation Voltage Reduction (CVR), which is now being developed for implementation at Hawaiian Electric in 2014. CVR schemes enable a utility to operate distribution systems at lower acceptable voltage ranges by using regulators and load tap changers, and other voltage regulating devices, at appropriate locations on the feeder line, constantly monitoring customer voltages and implementing new control software.

Voltage readings from sensors along the line or from smart meters at customer premises are used in utility control systems to maintain voltages at the lower limit of the tariff, thus reducing overall electricity consumption. Managing voltages on the grid becomes especially challenging with a high penetration of variable energy resources (such as residential photovoltaic systems and the Companies are actively engaged in various research activities to model and find solutions to this challenge.t

With CVR, the Companies could realize improved transmission and distribution system efficiencies through reduced system losses and reduced loads at substations, all of which reduce costs for our customers. According to the Green Circuits Project, EPRI observed that most test circuits exhibited an energy savings level between 0.5% and 1% for every 1% reduction in voltage. Actual results, however, will be site specific.

Table 12-2 shows the energy savings from VVO and CVR programs of various national utilities.

Table 12-2. Energy Savings from VVO and CVR Programs

Utility/Entity	Applications	Results
American Electric Power	Voltage & VAR optimization	~3% energy savings, depending on feeder
Dominion	Voltage optimization	~2-4% energy savings >1.0% reduction in energy for every 1% reduction in voltage
Georgia Power	Temporary voltage reduction (for peak reduction)	264 MW of peak demand reduced across 171 substations
Progress Energy	Voltage optimization	~1% reduction in energy for every 1% reduction in voltage
RW Beck (Northwest Utilities)	Voltage optimization	2%–3% energy savings across 11 utilities
Xcel Energy	Voltage and VAR optimization	2%–3% energy savings

Integrated Voltage and VAR Control (IVVC) controls both the voltage regulation devices and the VAR devices in a coordinated way, preventing individual devices from competing with one another (Figure 12-). The benefits include customer end-uses as well as effectiveness in aiding distribution and transmission operations.

Figure 12-1. Objectives, Constraints, and Controllable Variables of IVVC

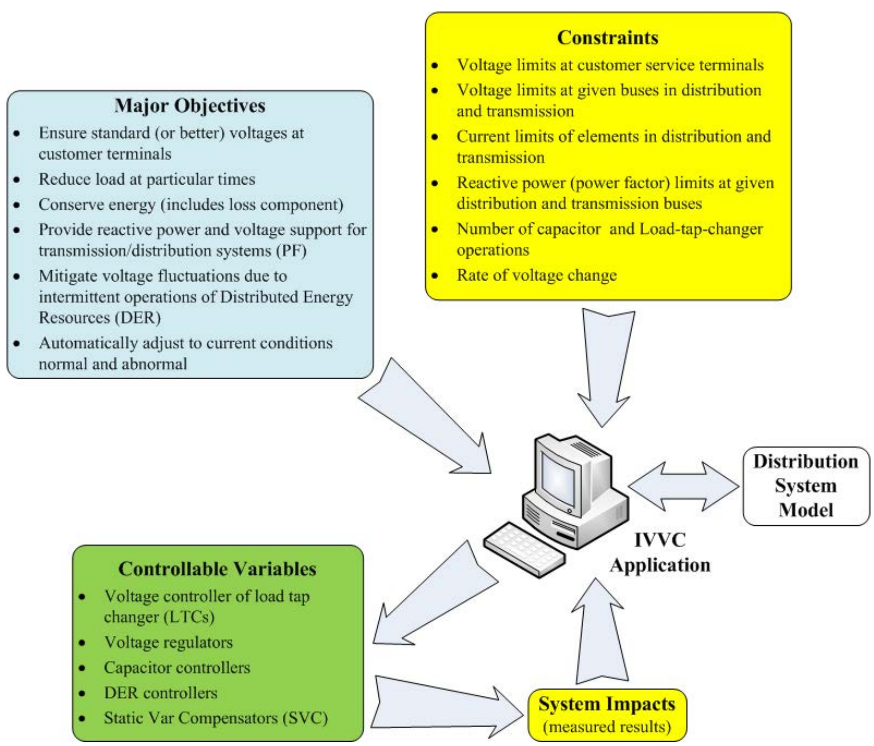

Table 12-3 provides a rough estimate of annual fuel cost savings that could be achieved if a 1% decrease in system load could be attained. This assumes a $20/MBtu fuel cost and a 10,000 Btu/kWh heat rate.

Table 12-3: Annual Fuel Cost Savings by a 1% Reduction in System Load

	HECO	MECO	HELCO	Total
Net Load (MWh)	7,000,000	1,000,000	1,000,000	9,000,000
Savings Percent	1.00%	1.00%	1.00%	—
Savings (MWh)	70,000	10,000	10,000	90,000
Fuel Cost Assumptions ($/MWh)	$200	$200	$200	—
Totals	$14,000,000	$2,000,000	$2,000,000	$18,000,000

AMI communication systems can send command signals to balance generation and demand by curtailing customer loads and enabling a more reliable and economic electric grid[52]. As stated in renewable integration studies[53], managing high penetration levels of variable renewable resources requires additional operating reserves.

Integrating large amounts of non-firm variable renewable energy into the grid is complex. The Companies lack information on and control of non-firm renewables, and must account for sudden changes in energy output due to variances in nature (such as how much the wind blows or the sun shines).

To respond to periods when energy from renewables wanes, the Companies can provide more online spinning reserves or use “quick starting” generators to return balance between supply and customer demand on the grid. Running additional generation to provide these reserves, however, adds to the operating cost and can reduce the amount of as-available energy that can be accepted by the grid.

Controlling customer loads might be a more cost effective solution. Theoretically, when renewable energy sources ramp down, the utility could send a signal to curtail customer loads to balance supply and demand long enough to start additional conventional generation. This eliminates the need to proactively run generation.

Hawaiian Electric implemented and continues to operate several direct load control (DLC) programs to control customer loads for emergency conditions and economic reasons. These DLC programs are the residential direct load control (RDLC[54]) and commercial and industrial direct load control (CIDLC[55]) programs. (See Demand Response Programs on page 7-19 for more information about these programs.)

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52 AMI provides 2-way communications compared to the 1-way communications used with Hawaiian Electric’s current load control programs (RDLC, SBDLC, and CIDLC).

53 Integration studies include the Maui Wind Integration Study, the Oahu Wind Integration Study, and the Hawaii Solar Integration Studies.

54 PUC Docket No. 2003-0166

55 PUC Docket No. 2003-0415

Hawaiian Electric and MECO are also conducting a Fast Demand Response (Fast DR[56]) Pilot Program designed as a "quick start" (less than 10 minutes) bridge resource primarily intended to facilitate grid operations with increasing levels of variable, intermittent renewable energy. Under specific ramp-down conditions, Fast DR could effectively supplement the need for spinning reserves. It includes two technical implementation approaches: semi-automated and automated. The Fast DR Pilot can provide market feedback for modifying the CIDLC program.

Hawaiian Electric's RDLC Program enables eligible residential customers to participate in an "interruptible" program for electric water heaters and central air-conditioning (A/C) systems. A radio-controlled switch installed next to a water heater or central A/C system turns off the appliance when signaled by Hawaiian Electric. The radio-controlled switch also includes an under-frequency relay that automatically disconnects the appliance from Hawaiian Electric's system if system frequency reaches a certain level in response to the loss of a major generating unit or other major system disturbance. Customers receive a monthly electric bill credit of $3.00 for electric water heaters and $5.00 for central A/C systems as an incentive for participating in the program.

One shortcoming of the existing RDLC and CIDLC programs is that they employ one-way communication; system operators have no information about the operating state of the devices they are controlling, either before or after they exercise a control command. Operators must rely on projected responses derived from statistical analysis rather than near real-time load impact estimates. AMI could allow two-way communications and control between customers and the utility. As a result, control center operators would have near real-time knowledge of available DR resources before curtailment events and could monitor the actual response when DR resources are dispatched.

Having access to detailed customer load data from the AMI system's meter data management system (MDMS) would allow the Companies' DLC programs to find and target key customers that could benefit the most from these programs. At the same time, the program would save money by not paying financial incentives to "free riders" (customers who do not use their A/C systems frequently or during periods of peak system usage). Modern load control switches are available with power (or current) monitoring sensors and can communicate over an AMI network (either directly or via a home area network such as ZigBee) to provide before and after event data.

Smart Grid communication systems monitor the utilization and health of distribution equipment, and allow proactive maintenance or replacement (for example, replacing overloaded transformers with larger EV loads). These proactive maintenance and upgrades reduce corrective maintenance conducted during emergencies, which serve to reduce costs, the duration of repair, and customer and public inconvenience.

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[56] PUC Docket No. 2010-0165

An Informative Grid

Smart Grid implementation focuses on enhancing a customer's experience with energy usage and with the Companies. Customer service has numerous facets including electric service reliability, power quality, utility responsiveness, energy consumption information, easy-to-use online tools (such as "what-if" scenarios for different pricing programs), new programs (such as Pre-Pay accounts), and overall customer value.

AMI provides customers with timely information to better manage their electricity consumption and related costs, and proactively motivate adjustments to consumption. The right information, tools, and formats will enhance customer service.

AMI captures interval electricity consumption allowing customers to review energy use hourly (or sub-hourly) through a web portal or on mobile devices (such as smart phones and tablet PCs). The web portal can show a customer's projected billing amounts and the level reached within the current tiered residential pricing structure at a given time. Customers can then take immediate action to address excessive usage. Seeing electricity consumption at any given moment has been shown at other utilities to reduce electricity consumption. Hawaii's high electricity rates encourage a reduction in energy use.

Interval electricity consumption also enables customer service to resolve a customer's complaint or concern about a high bill or questions about usage, as well as offering suggestions about how to use energy more efficiently or present scenarios for pricing options or new programs. AMI meters provide utility planners and operators with consumption, outage, and power quality data (voltages, momentary outages, and hot socket conditions) while other sensors and equipment on the grid (breakers, switches, faulted circuit indicators and transformer meters) provide status information to improve responsiveness and speed power restorations. When outages occur, the AMI meter sends a real-time alert about a power outage. In addition to quickly identifying pocket outages, bellwether meters located along a distribution circuit improve power quality management by providing a low-cost way to monitor voltages at transformers and provide the information needed to manage the distribution system as it becomes more dynamic.

An Enabling Grid

Pricing and Payment Programs

In addition to providing customers with much more granular and timely usage information, AMI systems utilizing web portals or smart phone applications can also estimate potential savings from various pricing programs (such as time-of-use (TOU), curtailment riders, critical peak pricing (CPP), and peak-time-rebates (PTR)). The Companies currently offer various TOU rates[57] for both residential and commercial customers and curtailment riders[58] for commercial and industrial customers, however these are static TOU programs and AMI systems would enable more dynamic pricing programs. The Companies have filed a request (Docket 2011-0392) for approval of a commercial and industrial dynamic pricing pilot program. As new programs are implemented, the Companies are committed to educating customers, understanding their expectations, and addressing the security and privacy of data.

Pre-Pay Metering, which allows customers to prepay for consumption, is also enabled through AMI. In this program, customers can review detailed electricity usage and credit balances. Customers are notified by phone, text message, or email to replenish low or zero balances. After appropriate notice and grace periods, service can be disconnected and quickly reconnected after payments are made.

Pre-Pay Metering eliminates significant deposits, enables smaller payment, and enables payments only when necessary — all without late payment fees. Case studies presented in a 2011 Chartwell Research report illustrate that customers on Pre-Pay Metering typically use 12–13% less energy while utilities report a customer satisfaction level of at least 84%. Actual results, however, will be site specific.

Distributed Renewable Energy Resources

Hawaii utilities and their customers have been adding distributed renewable energy resources to their power systems at an unprecedented pace over the last few years. Distributed generation capacity is now nearing 15% of system peaks on some systems and exceeding, in aggregate, the largest central station generating units on those systems. Distributed renewable energy resources integrated at this level impact both the overall system and energy distribution networks. Even though there are technical and operating challenges to adding large amounts of distributed generation on the system, this rapid pace continues.

In addition to the rapid growth of distributed PV system on the grid, Electric Vehicle (EV) adoption will likely increase, depending on the EV and gas

[57] TOU rates include Schedule U, TOU-R, TOU-G, TOU-J, Residential TOU EV, EV-R, and EV-C.

[58] Riders include Rider I, Rider M, and Rider T.

prices and the level of incentives that are provided. Large scale EV adoption and charging will also push the limits of the grid if not proactively managed.

One major issue is that the Companies do not have much data collection and control capabilities at the edge of the grid where distributed generation might be connected. Without this data, system planners and operators cannot determine the impacts of these generation resources or effectively operate with them. Thus, it is difficult to determine when more distributed renewable energy resources could be enabled. More data will help identify ways to interconnect and develop solutions to integrate distributed renewable resources.

To interconnect distributed renewable energy resources, the Companies currently perform initial and supplemental technical screens. Data is not always available to perform these screens since not all substations have SCADA or telemetry. In these situations, the Companies temporarily monitor the system and the data used to process requests. Because the data is only monitored for part of a year, the results might not represent the best or worst case scenarios. Adopting Smart Grid would provide continuous real-time monitoring, thus improving data accuracy. While implementing a Smart Grid might not enable greater interconnection of distributed renewable resources in all cases, it will enhance the data and system feedback giving the Companies a better understanding of the ongoing effects of distributed generation on the system. By adding visibility and control along the circuits at the customer level, the Companies can more accurately verify existing and future study results and effectively handle emerging issues on the grid as they arise.

A Smart Grid can increase monitoring at the substation level and at the customer level to enhance the data currently used in performing screens, both of which will help integrate renewables. Load data at the substation level inherently is a net value: a measure of the power being drawn from the circuit to serve load (the gross load) minus the power being provided to the circuit from distributed energy resources.

The true daytime load connected to a circuit is unknown because it depends on the amount of generation being supplemented by others along the circuit. Monitoring all generation on a circuit in addition to the net substation load values can better determine the gross customer load. Unmasking the load currently offset by customer generators will allow for higher load values used in the technical screens, which could result in increasing the amount of generation allowed. This information would also help validate and improve the forecast modeling of PV generation on the system.

Several pathways can collect PV production information: AMI, direct utility communications, or the Internet. Collecting PV production data also benefits the customer when coupled with interval net meter data and a customer web portal. With both sets of data time synchronized, the customer would know their actual load and PV production. They could use this information to monitor energy usage, observe abnormalities and inefficiencies, compare their usage to other customers, and monitor their PV production performance to better understand if energy usage or PV production caused their energy bill to change. This cannot be done with net energy data alone to a high degree of accuracy.

The Companies can manage system and circuit issues, plus emergencies, when distributed generation is controlled, and properly integrated and designed. Right now, however, the Companies must accommodate all connected distributed generation even during infrequent events (such as system restoration and temporary reconfiguration) because there is no practical way to temporarily limit the output of the large numbers of distributed generation connections. To better monitor and control the system, the Companies are working on demonstration projects to test different communication and control systems to develop an effective solution before this becomes a limiting issue.

Finally, the Companies continue to monitor the impact of distributed generation on under frequency load shed (UFLS) schemes. Following a disturbance (that is, the sudden loss of generation from the grid), the UFLS schemes disconnect a sufficient amount of load from predetermined circuits to restore the system frequency closer to normal levels. The power these circuits draw depends on the load served by distributed generation, which has become more unpredictable.

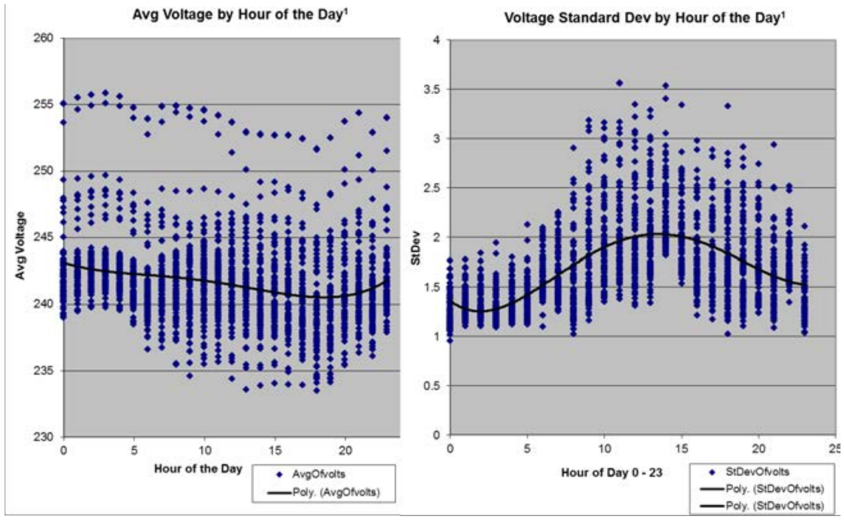
To accommodate a larger penetration of distributed generation, smarter, more adaptable or granular load shedding schemes and/or energy storage systems are needed to maintain system stability. An example of a more granular load shedding scheme is the frequency response aspects of Hawaiian Electric's RDLC program that sheds load at the customer level without disconnecting the distributed generation. The Company can and has changed the frequency setting of the load control devices remotely to adapt to changing system needs.

Demonstration Projects

The Companies are involved with several projects developing and demonstrating technologies and methodologies that gather system and generation information and provide some level of control for the energy resources being deployed at the edge of the grid (such as PV and electric vehicles). These demonstration projects include the DOE Maui Smart Grid Project, the Japan-US Maui Project (JUMP Smart), and the DOE Advanced Inverter project on Maui. These projects are being implemented and are scheduled to run through 2014 and into 2015.

The voltage profiles and variability information (Figure 12-2) from the Maui Smart Grid Project is an example of how Smart Grid systems (including AMI) can provide valuable information to both the system planners and system operators. The graph shows not only the extent to which variability increases during the day when PV production ramps up, but also provides information for more conventional operating issues (such as the voltages that are being provided when the PV is not operating).

Figure 12-2. Hourly Average Voltage Measurements and Variation



Also, as part of these demonstration projects, Hawaiian Electric is assessing the use of smart communicating inverters and other distributed control systems. The high penetration of distributed generation (such as residential PV systems) might become a problem unless the Companies have the ability to communicate with and use new control functions that are being developed.

In 2009, EPRI's Photovoltaic and Storage Integration Program (P174) began a series of studies related to the high penetration of distributed energy resources (DER). One research area focused on the communication aspects of DER integration, which led to launching a broad industry collaborative in 2009 to identify a common way of integrating smart, communicating inverters into utility systems. These features and functions of smart inverters were identified:

- Connecting and disconnecting from the grid
- Adjusting maximum power delivery to the grid
- Controlling the power factor, smart volt, and VAR
- Charging and discharging storage management by price or command
- Monitoring state and status
- Logging events and history
- Adjusting and setting time

These functional use cases formed the basis for which smart inverter requirements are defined and help manufacturers to produce standardized products that lead to more cost-effective and interoperable products. The Companies anticipate that widespread use of smart inverters in Hawaii will be important in addressing the integration of high distributed PV levels. The Companies are closely engaged with HNEI, Hitachi, and EPRI to evaluate and test this technology. The Companies are also supporting EPRI's work on the revision process for IEEE 1547 that will set the standards for these advanced inverter functions.

Hawaiian Electric and MECO are also actively researching managing customer loads by applying direct load control, smart inverters (on PV systems), and EV charge management on Maui through collaborative projects with EPRI, HNEI, DOE, and NEDO (Japan). This research will provide greater insight into designing and implementing systems and methods to manage high levels of renewable energy on our power grids and opportunities to gradually implement viable solutions over the next several years.

These projects help test and develop new technologies that can be cost effectively deployed throughout the system.

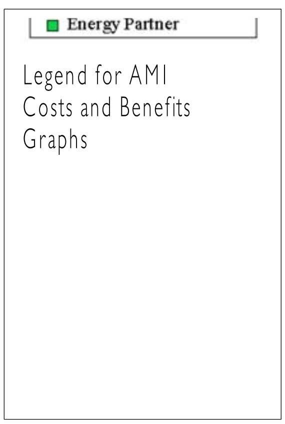
Exhibits

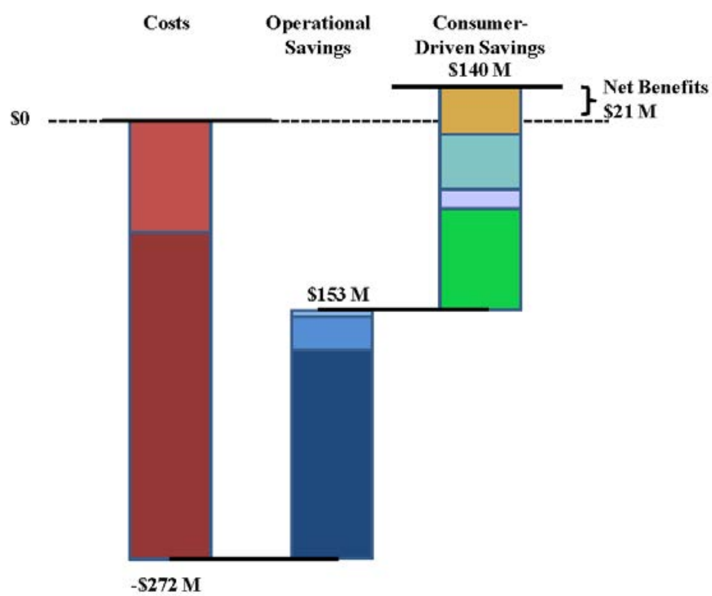
Exhibit I: Benefit-Cost Business Case Analyses

The Institute for Electrical Efficiency (IEE) published a 2011 white paper entitled *The Costs and Benefits of Smart Meters for Residential Customers*, which illustrates the range of values that IEE has projected for the AMI component of the Smart Grid for various "types" of utilities: committed (Figure 12-3), exploratory (Figure 12-4), and cautious (Figure 12-5). The IEE white paper illustrates the potential differences in business cases and the uniqueness of each utility's business case. The benefits included labor and equipment efficiencies, demand response energy efficiencies, and benefits of outage time reductions.

A committed utility (Figure 12-3) has relatively high energy prices, primarily natural gas-fired generation, and a mandate to aggressively pursue renewable generation.

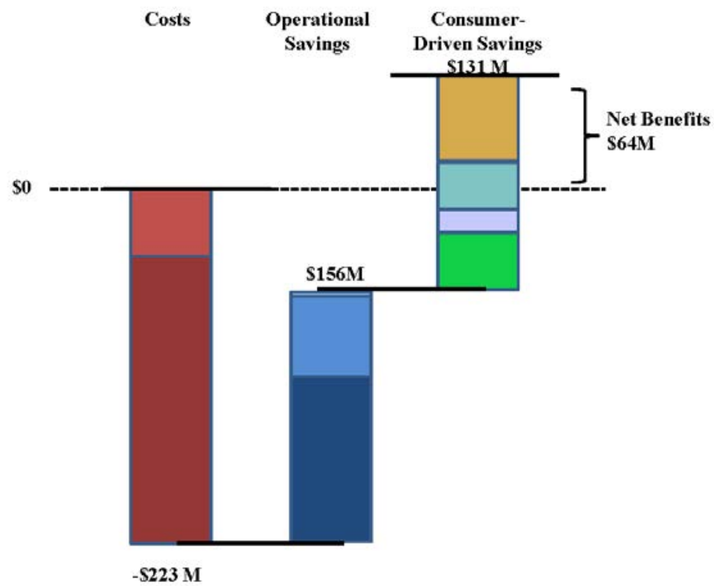
Figure 12-3. AMI Costs and Benefits for a Committed Utility





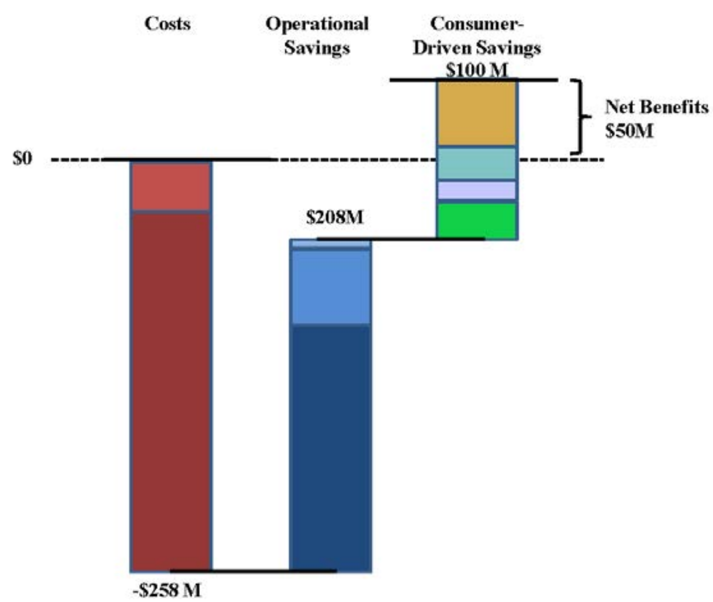
An exploratory utility (Figure 12-4) has relatively low-cost generation available, high population density, and highest demand in winter months.

Figure 12-4. AMI Costs and Benefits for an Exploratory Utility



A cautious utility (Figure 12-5) has low population density, high annual demand growth, and coal, nuclear, and natural gas dominant in its generation portfolio.

Figure 12-5. AMI Costs and Benefits for a Cautious Utility



San Diego Gas & Electric

Application of San Diego Gas & Electric 05-03-015
Chapter 2 – AMI Business Vision, Policy, and Methodology
July 14, 2006 Amendment

Table 12-4: San Diego Gas & Electric Benefit-Cost Analysis (Millions of 2006 Dollars)

	Operational Benefits		Demand Response Benefits			Costs			
	O&M, Capital	Theft	Avoided DRPs + Net T&D Benefits	Avoided Capacity and Energy	Total Benefits	O&M	Capital	Total Costs	Net Benefits
Societal	$336	$69	$113	$262	$780	$215	$456	$671	$110
Revenue Requirements	$362	$69	$108	$262	$801	$212	$530	$741	$60

Electric Power Research Institute (EPRI)

Estimating the Costs and Benefits of the Smart Grid

Table 12-5: Electric Power Research Institute Cost Benefit Analysis

(Billions of Dollars)	20-Year Total
Net Investment Required	338–476
Net Benefit	1,294–2,028
Benefit-to-Cost Ratio	2.8–6.0

Baltimore Gas and Electric Company

Table 12-6: Baltimore Gas and Electric Benefit-Cost Analysis

(Millions of Dollars)	NPV Benefits	NPV Costs	TRC
BGE Smart Grid Business Case	$1,322	$415	3.2

Southern California Edison

Edison SmartConnect™ Deployment Funding and Cost Recovery
Exhibit 3: Financial Assessment and Cost Benefit Analysis

Table 12-7: Southern California Edison Benefit-Cost Analysis

Project Cost Benefit Analysis Results
($Nominal and 2007 Present Value of Revenue Requirement, in Millions, Rounded)

	Nominal	PVRR
Benefits		
Operational Benefits		
During Deployment Years	278.2	
During Post-Deployment Years	4,299.0	
Demand Response Benefits		
During Deployment Years	216.2	
During Post-Deployment Years	2,792.6	
Subtotal Operational Benefits	4,577.2	
Subtotal Demand Response Benefits	3,008.8	
Total Benefits	**7,586.0**	**2,076.0**
Costs		
Phase II Costs (Pre-deployment)	45.2	
Deployment Costs		
Acquisition of Meters and Communication Network Equipment	838.0	
Installation of Meters and Communication Network Equipment	296.6	
Implementation and Operation of New Back Office Systems	191.2	
Customer Tariffs, Programs and Services	112.1	
Customer Service Operations	84.1	
Overall Program Management	45.6	
Contingency	147.3	
Post-Deployment Costs		
Billing	127.1	
Call Center	93.5	
Meter Services	399.1	
Back Offices Systems	344.4	
Customer Tariffs, Programs and Services	245.0	
Subtotal Pre-Deployment Costs	45.2	
Subtotal Deployment Costs	1,714.9	1,627.0
Subtotal Post-Deployment Costs	1,209.0	340.0
Total Costs	**2,969.1**	**1,967.0**
Total Benefits Less Total Costs	**4,616.9**	**109.0**

Commonwealth Edison Company (ComEd)

Advanced Metering Infrastructure (AMI) Evaluation – Final Report (by Black & Veatch)

Table 12-8: Commonwealth Edison Benefit-Cost Analysis

Financial Highlights and Summary (5-Year and 10-Year Deployment, $ in millions)

Item	Base Case (5-Year Deployment)	Base Case (10-Year Deployment)
A. Costs (Cumulative 20 years)		
O&M Expense for AMI System	$665	$653
New Capital Investment for AMI System	$996	$1,031
Sub-Total	***$1,661***	***$1,684***
B. Operational Benefits & Delivery Service Revenues (Cumulative 20 years)		
Operational Efficiencies and Cost Reductions	$1,625	$1,539
Avoidance of Capital Expenditures	$3	$3
Collection of Delivery Service Revenues Due to Reduction in UFE and CIM	$564	$531
Sub-Total	***$2,192***	***$2,073***
C. Additional Benefits (Energy, Transmission and Other Rider Cost Reductions and Revenues) (Cum. 20 yrs)		
Reduction in Energy Purchased Power Costs Due to Reduction in UFE and CIM[4]	$708	$667
Collection of Energy and Other Revenues Due to Reduction in UFE and CIM	$1,051	$991
Reduction in Bad Debt Expenses	$791	$745
Sub-Total	***$2,550***	***$2,403***
D. Total (Cumulative 20 years)		
Benefits Less Costs	$3,081	$2,795
E. Net Customer Impact		
Net Present Value (NPV)[5]	***$1,296***	***$1,152***
Discounted Payback Period (Customer Perspective)	*8 years*	*9 years*

All $ values in Millions. NPV calculated based on discount rate = 4.27% (20-yr Treasury Rate)

Pacific Gas and Electric Company

Table 12-9: Pacific Gas and Electric Stipulated AMI Project Costs

Line No.	Cost Category	Estimated Costs Deployment (Last Meter Installed in 2011) and O&M (Through 2010) ($ in millions)	PVRR ($ in millions)
1	Project management costs	$87.9	$87.5
2	Risk-based allowance	128.8	135.0
3	Meters and modules	637.4	799.2
4	Network materials	83.6	98.5
5	AMI operations	40.9	119.1
6	Interface and systems integration	94.0	155.6
7	Interval billing system	85.0	109.1
8	Meters/modules installation	326.1	355.9
9	Electric network and WAN installation	87.2	99.1
10	Gas network and other installation	5.8	6.9
11	Meters/modules QA sample testing	2.8	2.3
12	Meter operations costs	22.6	129.3
13	Customer contact-related costs	32.3	45.5
14	Customer exceptions processing	6.6	5.3
15	Marketing and communications	23.1	22.6
16	Customer acquisition	54.8	44.0
17	Other employee related costs	20.7	43.4
18	Total Estimated Project Costs *(totals subject to rounding error)*	$1,739.4	$2,258.3

Table 12-10: Pacific Gas and Electric Stipulated AMI Project Benefits

Line No.	Benefit category	Annualized Benefit After Implementation (2005 $ million)	PVRR ($ in millions)(a)
1	Operational meter reading	$86.2	($1,074.4)(b)
2	Electric Transmission and Distribution	12.8	(195.7)
3	Meter Operations	7.0	(103.4)
4	Customer Contact	2.7	(39.9)
5	Billing Benefits	18.6	(215.3)(b)
6	Gas Transmission and Distribution	1.2	(9.9)
7	Reduced Software License Expense	5.0	(48.1)
8	Remote Turn-On/Shut-Off	11.5	(102.0)(b)
9	Other Employee-Related Costs	16.8	(218.5)
10	Total Annual Benefit	$161.8	($2,007.2)
11	Reduced Equipment Replacement (2011 $)	8.5	(10.2)
12	Deferred Meter Testing	1.6	(6.8)
13	Total One-Time Benefits	$10.1	($17.0)
14	Total Benefits *(totals subject to rounding error)*		($2,024.2)

(a) PVRR values in parentheses are a reduction in revenue requirement.

(b) PVRR totals for these benefits are net of severance costs.

Exhibit II: Energy Theft Benefits

Utilities Telecom Council (UTC) Research

Smart Grid Economics – Making the Business Case for Smart Network

This report analyzes the value proposition that a Smart Grid program may offer given a set of realistic assumptions regarding system costs and benefits. The results of the analysis show that for a given deployment, the following results may be achieved:

- A comprehensive Smart Grid deployment involving a full set of programs in three key areas — (1) advanced metering and outage management, (2) distribution automation, and (3) distributed energy resources — for an electric utility of one million electric meters may expect to require capital investment of $828 million over a three-year period.
- System benefits calculated by the end of a ten-year forecast period are likely to exceed $110 million per year.
- The internal rate of return (IRR) for the program is calculated at 13.8% without accounting for the value customers may place on the increased reliability of the electric grid; when factoring in these customer benefits, IRR exceeds 35%.

Table 12-11: Utilities Telecom Council Research Energy Theft Benefit

ENERGY THEFT ESTIMATES

	Estimated Revenue Lost from Energy Theft	% of Losses Recoverable with AMI			% of Revenues Recoverable with AMI
		Min	Max	Midpoint	
EPRI Study	1.0%	20%	30%	25%	0.25%
SDG&E	0.30%	NA	NA	8.5%	0.03%
SCE	0.25%	NA	NA	25%	0.06%
Duke Power	0.50%	NA	NA	25%	0.13%
Dominion	NA	NA	NA	NA	0.10%
Low Estimate					0.03%
High Estimate					0.25%
Average					0.11%
Midpoint					0.14%

Chapter 13: Essential Grid Ancillary Services Analysis

The Companies must analyze the comparative costs and benefits of implementing new technologies that would decrease reliance on fossil fuel generation while providing essential grid ancillary services and increasing renewable energy generation. These ancillary services can include providing quick-response capacity through modification of existing fossil and renewable energy generating units, customer demand response programs, and energy storage resources.

New Technologies, Measures, and Strategies

The Companies' position is that new technologies, measures, and strategies should be explored and utilized if they are cost-effective or reduce ratepayer exposure to risk, and if they meet each of the following system objectives:

- Maintain or improve present levels of system reliability and security.
- Ensure that resource capabilities needed for system security will be made available.
- Provide flexibility for the system operator to change its use of resources in response to changing relative costs, system operational needs, and resource availability.

The Company's analysis of resource alternatives is not complete, but has been occurring in steps that include:

1. Determining the core set of system constraints on a system.
2. Determining the value of ancillary services for a given base resource portfolio.
3. Identifying alternative resources and/or changes to the base resource portfolio that could provide commensurate reliability to the base resource portfolio.
4. Selecting resource alternatives that achieve the system objectives outlined in the previous three steps.

Determining the Value of Alternative Ancillary Services

To accomplish these analytical steps, the Companies support using the methodology consistent with that proposed in the Reliability Studies Working Group (RSWG) GE Ancillary Services report. This methodology is based on a four-step analysis:

1. Complete an annual production cost simulation for the base resource portfolio for each base case system.
2. Complete an annual production cost simulation that incorporates resource alternatives using the same base case system identified in the previous step. (An example would be locating battery systems at key transmission constraints that might alleviate certain generation requirements.)
3. Calculate the cost difference between the base resource portfolio and the alternative resource portfolio(s).
4. Assess and evaluate the least-cost portfolio of resources based on the findings of acceptable resource combinations identified in the previous

steps. This might necessitate using an iterative solution to provide the best method of providing the required services.

This approach is similar to that used in the EPS cycling study performed for HELCO and MECO in the RSWG docket proceedings. That study examined acceptable resource combinations for system security based on existing and near-term resources and evaluated potential for down-regulation from wind. The set of resources required that address security constraints and to meet system objectives were then incorporated into an assessment of production cost.

As recommended in the GE report, the production cost assessment would evaluate the potential combinations of resources to determine lowest-cost portfolio, including production cost and capital expenditure while observing system reliability needs. The Companies recommend that the analysis be based on industry accepted methods which capture all variable production costs, including impacts of variable and distributed generation, in order to accurately assess the relative costs of various scenarios.

The EPS cycling study was performed using an hourly resolution. Some resources might address shorter-term system constraints. As such, the cost-benefit analysis would need to be conducted through tools other than production simulations to capture cost savings for transient operational conditions.

The evolution of the island power systems that incorporate greater amounts of distributed and variable generation requires the security analysis and production cost analysis to become more sophisticated. Due to the significant cost and reliability impact of these decisions on future power systems, the Companies believe investment in the required detailed modeling and analysis is necessary.

Hawaiian Electric plans to issue an RFP this year to conduct modeling and analysis to derive the value of ancillary services. The analysis is scheduled for completion in 2013. The study could continue into the following year, if necessary, in order to further develop the substance of the information, finalize the production simulations, and complete a report on the work.

Considering Risk

The risk impact of the alternatives must be considered against the cost-effectiveness of various resources, so long as there is an overall benefit. For example, an alternative that provides the important benefit of reducing the consumption of fossil fuels must be considered even if it does not affect cost-effectiveness.

Relatively new technologies might increase risk because their ability to meet the technical requirements of a system constraint may be less certain than current generation resources. Investing in emergent technologies having limited history in commercial application can also be risky, but ultimately might hold the promise of increased benefits.

Some risks that should be considered include obsolescence due to technology change, fuel price volatility, changing system demand levels, and the ability of the alternative resource to be available when needed by the system operators.

Selecting Alternative Resources for Consideration

Using the four-step analysis process, a least-cost portfolio of resources can be identified for resources whose technical capabilities and costs can be quantifiable and analyzed, in order to compare them against the base resource portfolio.

Moreover, the Companies is investigating alternatives to generation whose costs and risks are not defined, but can decrease our reliance on fossil-fuel generation while providing essential grid ancillary services and accommodating expected increases in the proportions of variable and intermittent renewable generation. A promising alternative might be first implemented on a small scale basis to validate the cost and implications on system operations. This small scale approach not only reduces risk, but can prudently establish assumptions by analyzing and evaluating options to select an appropriate mix of resources.

One of the key objectives of Hawaiian Electric's three demand response (DR) programs[59] is to quantify and evaluate operational risks and technical capabilities (such as the availability and performance of the demand-side resources). This evaluation enables an assessment of a DR program's ability to provide load curtailments at the expected levels and when called for by the system operator.

Another risk associated with DR programs is whether the size of the available resource can sufficiently provide system benefits. A study planned to be completed in 2014 will estimate the amount of DR potentially available over the next 20 years. This study will use customer end-use data currently being collected by the Commission's consultant for the Commission's energy efficiency potential study. The customer end-use data is scheduled to be available before the end of 2013.

The Companies are taking a measured approach to evaluate commercial adoption of energy storage technologies due to technology risks and an evolving business case. To help offset the risks, the Companies are partnering with various external entities.

Hawaiian Electric and HELCO are partnering with the University of Hawaii's Hawaii Natural Energy Institute (HNEI) to test the ability of HNEI-purchased (via federal grant) lithium titanate battery energy storage systems (BESS). The tests will evaluate whether batteries can perform wind smoothing on Hawaii Island (operational since December 2012) and effect

[59] Hawaiian Electric currently implements the Residential Direct Load Control (RDLC) and the Commercial and Industrial Direct Load Control (CIDLC) Programs. Hawaiian Electric and MECO both implement the Fast DR Pilot Program.

power smoothing and voltage regulation on a feeder with high distributed PV penetration on Oahu (installation targeted for 1Q 2014).

MECO plans to install a lithium ion battery at its Wailea substation on Maui in 2Q 2013 as part of the Department of Energy (DOE)-funded, HNEI-led Maui Smart Grid project. HELCO received DOE stimulus funding (through the State of Hawaii Department of Business, Economic Development and Tourism) to install lithium ion batteries at two customer-owned PV projects on Hawaii Island in July 2012 to help evaluate the battery's ability to smooth out fluctuations of commercial-scale PV projects.

These projects will help quantify the technical potential, costs, and risks associated with these alternative resources, which can then be incorporated into alternative scenarios for cost-benefit and risk analyses. These analyses and results of research and demonstration projects will help the Companies better understand the business case for energy storage, including what applications and operating structures provide the highest operational benefits and customer value.

Actions to Increase Ancillary Service Capabilities

The Companies continue to aggressively pursue solutions that are economically and technically beneficial. These solutions include projects in DR and BESS, and modifications to existing generating units. The Companies also continue to increase the available ancillary service capabilities of existing resources through power plant modifications (such as reducing minimum dispatch limits to increase dispatch range and increasing available ramp rates).

The Companies seek to require technical and operational requirements that enable ancillary service capabilities for future generating resources. The Companies are also renegotiating for increased capabilities in existing power purchase contracts. An example of this is the recent expansion of the Puna Geothermal Venture plant increasing generation by 8 MW (for a total of 38 MW), adding frequency droop capabilities to its facility, adding remote voltage regulation control, and providing dispatchability through HELCO's Automatic Generation Control system to facilitate management of intermittent and variable resources and exploring frequency response in existing wind plants.

Chapter 14: Transmission Planning Analysis

The Companies are constantly evaluating the efficiency and effectiveness of its transmission and subtransmission systems, and implementing measures as appropriate. Specifically for this IRP planning cycle, the Companies are comparing the costs and benefits of meeting system and local load growth, complying with reliability planning criteria, interconnecting new generation, retiring or replacing infrastructure, mitigating transmission bottlenecks, and assessing the transmission capacity (and other grid operational constraints) while solar or wind resources are being curtailed.

The transmission planning analysis for:

- Hawaiian Electric's planning starts on page 14-2.
- MECO's starts on page 14-6.
- HELCO's starts on page 14-15.

Hawaiian Electric Transmission Planning Analysis

Hawaiian Electric has developed potential transmission requirements for the next ten years (2014 through 2023) as part of the 2013 IRP.

Planning Assumptions

Two forecasts, based on the Blazing a Bold Frontier and the No Burning Desire IRP scenarios (Table 14-), represent the extremes of the available forecasts. Load flows are based on 2011 actual load distribution, and were then scaled up evenly throughout Oahu.

The transmission planning analysis was based on 20-year load forecasts of the upper and lower bounding scenarios: Blazing a Bold Frontier and No Burning Desire.

Table 14-1: Ten-Year Hawaiian Electric Load Forecasts (MW)

Year	Blazing a Bold Frontier	No Burning Desire
2012	1,149	1,196
2013	1,139	1,237
2014	1,126	1,278
2015	1,112	1,323
2016	1,096	1,369
2017	1,078	1,408
2018	1,051	1,441
2019	1,039	1,487
2020	1,026	1,525
2021	1,014	1,549
2022	1,002	1,571
2023	991	1,594

The analysis included the following assumptions:
Halawa Substation Reconfiguration is completed in 2018.
Honolulu Power Plant is not available.
Waiau 3 and Waiau 4 plants are not available.
200 MW of firm generation is added in West Oahu for the Hawaiian Electric 200 MW request for proposal (RFP).
200 MW as-available wind generation from Lanai is added and connected to the Iwilei Substation.

- 200 MW as-available generation is added in North Oahu and connected to the Wahiawa Substation.

Hawaiian Electric Ten-Year Summary

For the transmission planning analysis, load flows were performed for contingencies under steady-state conditions: N-1 (one transmission facility is out) and N-2 (two transmission facilities are out). Stability runs were not performed for the IRP.

Blazing a Bold Frontier

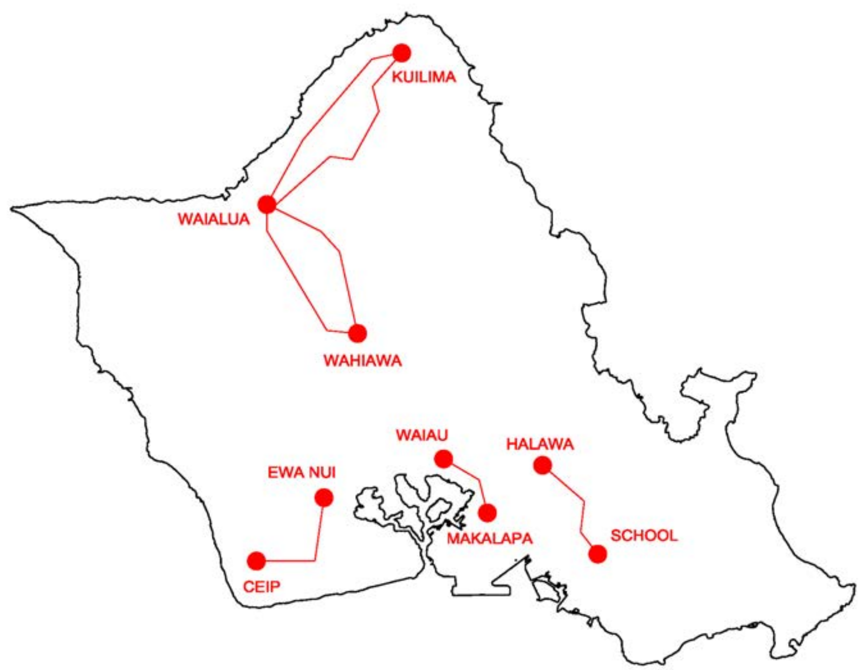
For the Blazing a Bold Frontier load forecast, the system load is reduced from 1,149 MW in 2012 to 991 MW in 2023. No additional transmission facilities are required for this scenario. To accommodate the load decrease, as-available generation might have to be curtailed.

To connect 400 MW of as-available generation, the additional transmission facilities described in Kahuku Area to Wahiawa Line (page 14-4) and Lanai Wind Farm to Iwilei Substation (page 14-5) might be required.

No Burning Desire

For the No Burning Desire load forecast, the system load is increased from 1,149 MW in 2012 to 1,594 MW in 2023. Based on the N-1 and N-2 contingency analyses, several transmission facilities and capacitor banks would be required to avoid potential line overloads and low-voltage problems. These upgrades are depicted in Figure 14-.

Figure 14-1. Hawaiian Electric Potential Transmission Network Upgrades



Halawa to School Line

A #2 138kV line may need to be added between the Halawa and School substations. This is triggered by line overload conditions due to load growth. The estimated cost is $22.8 million (assuming 6 miles of overhead line at $3.8M a mile).

CEIP to Ewa Nui Line

A #2 138kV line may need to be added between the CEIP and Ewa Nui substations. This is triggered by line overload conditions due to load growth. The estimated cost is $26.6 million (assuming 7 miles of overhead line at $3.8M a mile).

Waiau to Makalapa Line

The #1 138kV line between the Waiau and Makalapa substations may need to be reconductored. This is triggered by line overload conditions due to load growth. The estimated cost is $16 million (assuming 4.2 miles of overhead line at $3.8M a mile).

Downtown and Kapiolani Reactive Power

Approximately 150 MVAR of reactive power support — cap banks, synchronous condensers, and/or DVARs — needs to be added in the Downtown and Kapiolani areas. Potential sites include the Iwilei, Archer, and Kamoku substations and the Honolulu Power Plant.

This is triggered by low voltage due to the Honolulu Power Plant's retirement and load growth. The estimated cost is $12 million (assuming twelve 12.6 MVAR cap banks at $1M each).

Kahuku Area to Wahiawa Line

Two 138kV lines may need to be added from the Kahuku area to the Wahiawa Substation by overbuilding both the Wahiawa to Kahuku and the Wahiawa to Kuilima 46kV line routes. This is triggered by 200 MW of new as-available RFP generation (assumed to be in the North Shore area) to connect to the 138kV system at the Wahiawa substation. The 46kV feeders in the area are already at maximum capacity with the existing Kahuku and Kawailoa wind farms.

The estimated cost is $201.4 million (assuming 29 miles of new 138kV overbuild for the Wahiawa to Kahuku route and 24 miles overbuild for the Wahiawa to Kuilima route at $3.8M a mile).

Lanai Wind Farm to Iwilei Substation

There were no transmission facilities identified for connecting the 200 MW Lanai Wind Farm to Iwilei substation in the load forecasts for the two scenarios. To avoid overloads, additional facilities might be required under minimum load conditions depending on the load level and load distribution. At this time, costs have not been estimated.

Kamoku to Pukele Line

Adding a 138kV line between the Kamoku and Pukele substations is an option for increasing reliability for the Pukele, Kamoku, Kewalo, and Archer substation loads. The East Oahu Transmission Project was installed as an alternative to the Kamoku–Pukele line to increase reliability for the East Oahu area by providing more load transfer capability on the 46kV system level. Installing a line between Kamoku and Pukele, however, is the more complete solution for increasing reliability to East Oahu. At this time, costs have not been estimated.

MECO Transmission Planning Analysis

MECO has developed potential transmission requirements for the next 20 years (2014 through 2023) as part of the 2013 IRP.

Planning Assumptions

MECO used twenty-year load forecasts for the four IRP scenarios for the islands of Maui, Molokai, and Lanai to develop potential transmission requirements. The transmission planning analysis was first developed for the next five years (2014–2018), then information was added to address up to 10 years of planning. Additional analysis would need to be conducted to address the full scope of 20 years.

Maui Assumptions

Load forecasts for the four IRP scenarios for Maui are presented in Table 14-2, however only two scenarios showed significant changes in load. The load forecasts for the Blazing a Bold Frontier and No Burning Desire scenarios represent the extreme cases by 2018 for the load forecasts.

Table 14-2. Five-Year Maui Load Forecasts (MW)

Year	Blazing a Bold Frontier	Stuck in the Middle	No Burning Desire	Moved by Passion
2014	178	193	208	191
2015	174	194	216	191
2016	171	194	225	191
2017	168	195	234	191
2018	165	197	244	193

The analysis included the following assumptions for Maui:

- Load flow cases are based on 2012 peak actuals.
- When scaled, the loads are uniformly distributed.
- Generation for HC&S is 12 MW; for KWP 1 and 2 is 30 MW and 21 MW respectively; and for Auwahi is 21 MW.
- A Kaonoulu substation is added in 2015.
- A Kamalii Substation and MPP–Kamalii 69kV line is added in 2017.
- Convert Waiinu-Kanaha 23kV transmission line to 69kV and related substation upgrades in 2018.

Molokai Assumptions

The load forecasts for Molokai for all four scenarios (Table 14-3) change very little over the next five years.

Table 14-3. Five-Year Molokai Load Forecasts (MW)

Year	Blazing a Bold Frontier	Stuck in the Middle	No Burning Desire	Moved by Passion
2014	4.9	5.2	5.3	5.2
2015	4.8	5.2	5.3	5.1
2016	4.6	5.1	5.2	5.0
2017	4.5	5.1	5.2	5.0
2018	4.3	5.0	5.2	4.9

The analysis included the following assumptions for Molokai:
- Load flow cases are based on 2012 peak actuals.
- When scaled, the loads are uniformly distributed.

Lanai Assumptions

Similar to Molokai, the load forecasts for Lanai for all four scenarios (Table 14-4) change very little over the next five years.

Table 14-4. Five-Year Lanai Load Forecasts (MW)

Year	Blazing a Bold Frontier	Stuck in the Middle	No Burning Desire	Moved by Passion
2014	4.1	4.3	4.6	4.2
2015	4.0	4.2	4.5	4.2
2016	4.0	4.2	4.6	4.1
2017	3.9	4.1	4.6	4.0
2018	3.8	4.2	4.7	4.1

The analysis included the following assumptions for Lanai:
- Load flow cases are based on 2012 peak actuals.
- When scaled, the loads are uniformly distributed.

Maui Five-Year Summary

The load forecasts for the Blazing a Bold Frontier and No Burning Desire scenarios change significantly over the next five years. Because the load forecasts for the Stuck in the Middle and Moved by Passion scenarios change little over the next five years, the transmission planning analysis for these scenarios is based on the No Burning Desire scenario.

As stated under the Maui planning assumptions, two substations are planned — the Kaonoulu Substation in 2015 and the Kamalii Substation in 2017 — to address the load in the Kihei/Wailea area, thus strengthening the Maui electrical system.

Blazing a Bold Frontier

Because the load forecast for this scenario decreases from 178 MW in 2012 to 165 MW in 2018 (see Table 14-2), no additional transmission changes are necessary. As-available generation, however, might need to be curtailed.

No Burning Desire

The load forecast for this scenario increases aggressively from 208 MW in 2014 to 244 MW in 2018 (see Table 14-2). The Maui five-year transmission plan adds the Kaonoulu Substation in 2015 and the Kamalii Substation in 2017. The Kaonoulu Substation has connecting lines from MPP and Kihei. Besides adding the Kamalii Substation between Kihei and Wailea, the plan adds a 69 kV transmission line from MPP to the Kamalii Substation. Estimated costs are depicted in Table 14-5, with references to tables with cost breakdowns for each upgrade. Upgrading the existing Waiinu–Kanaha 23kV to a 69kV helps alleviate loading on the tie transformers. With the conversion, some substations tied to the Waiinu–Kanaha 23kV line will also need to be converted. This work is projected to be completed in 2018.

Table 14-5. Maui Five-Year Transmission Plan and Estimated Costs

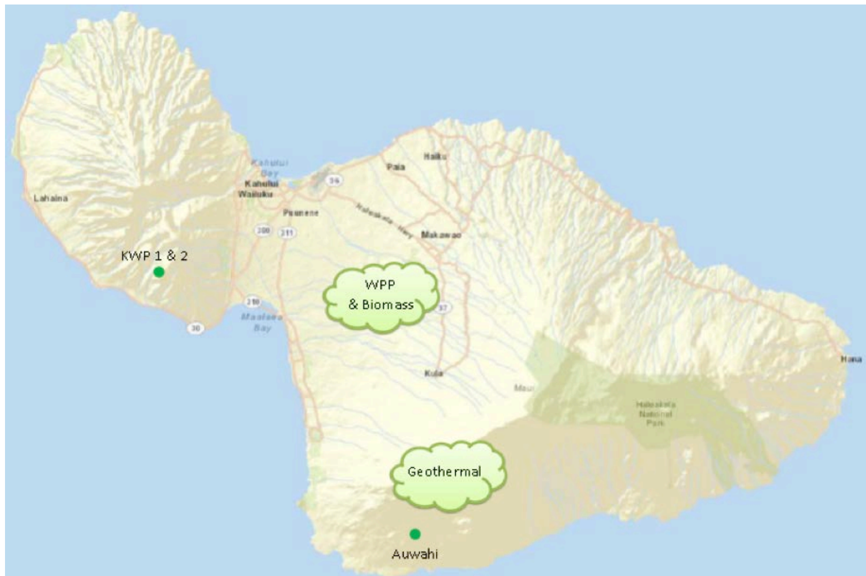
Year	Transmission Requirements	Estimated Costs
2015	Kaonoulu Substation (see Table 14-8)	$14,100,000
2017	Kamalii Substation and MPP–Kamalii 69kV transmission line (see Table 14-9)	$31,500,000
2017	Waena Dispatch Center	$7,000,000
2018	Substation Work	$28,600,000

Note: Each upgrade contains a cross reference to a table that details cost breakdowns.

Maui Ten-Year Summary

The resource locations for Maui's ten-year transmission upgrade requirements are depicted in Figure 14-2. All costs estimates are shown in Table 14-6.

Figure 14-2. Maui Assumed Resource Locations



Waena Power Plant: Phase I, II, and III

Future firm generation is assumed to be located at the Waena Power Plant (WPP). It is assumed that the WPP is expanded in three phases, depending on when the additional generation is needed.

WPP Phase I expansion will be a 25 MW CT. It requires a switchyard and overhead lines that tap the existing Kanaha–Pukalani 69kV transmission line.

WPP Phase II will add CT2 and ST1 completing the first set of dual train generators. The project needs a double 69kV circuit of approximately two miles of 556 AAC to tap the existing MPP–Kealahou 69kV transmission line.

WPP Phase III interconnects the second set of dual train generators: CT3, CT4, and ST2.

Geothermal

If geothermal was considered as a renewable resource, the Companies assume 25 MW firm power tying into the existing Auwahi–Kealahou 69kV transmission line. The upgrade needs two interconnection substations — one near the tie and the other at the site — and a 10-mile 336 AAC double 69kV circuit to connect the two substations.

Biomass

If biomass is considered as a renewable resource after all phases of WPP are completed, the Companies assume 25 MW firm power interconnected to the system at WPP sited approximated 0.5 miles away from WPP.

Estimated Transmission Costs

Table 14-6. Maui Ten-Year Transmission Plan and Cost Estimates

Year	Project	Transmission Requirements	Estimated Costs
TBD	WPP Phase I	Waena switchyard and 69kV transmission lines (see Table 14-10)	$7,000,000
TBD	WPP Phase II	Interconnection for CT2 and ST1, and double 69kV circuit (see Table 14-11)	$8,000,000
TBD	WPP Phase III	Interconnection for CT3, CT4, and ST2 (see Table 14-12)	$2,500,000
TBD	Waiinu–Kanaha 69kV	Convert existing Waiinu–Kanaha 23kV transmission line to 69kV (see Table 14-13)	$28,600,000
TBD	Geothermal	Two interconnection substations and 10-mile double 69kV circuit (see Table 14-14)	$38,000,000
TBD	Biomass	Interconnection substation and 0.5-mile 69 kV line (see Table 14-15)	$4,600,000

Note: Each upgrade contains a cross reference to a table that details cost breakdowns.

Molokai and Lanai Five-Year Summary

Because the load forecasts change little for all four scenarios for Molokai (Table 14-3) and Lanai (Table 14-4), the transmission system will not need to be expanded if no renewable resources are added to the system.

Some transmission lines might be deteriorated and will need to be reconductored to 336 AAC. An estimated cost to reconductor the deteriorated lines is $361,000 a mile.

Molokai and Lanai Ten-Year Summary

The resource locations for Molokai's ten-year transmission requirements are depicted in Figure 14-3. All costs estimates are shown in Table 14-6.

Figure 14-3. Molokai Assumed Resource Locations

The resource locations for Lanai's ten-year transmission requirements are depicted in Figure 14-4. All costs estimates are shown in Table 14-6.

Figure 14-4. Lanai Assumed Resource Locations

Wind, Wave, and PV

The resource plans for Molokai and Lanai considers wind, wave, and photovoltaics (PV) as renewable resources. To interconnect these resources, it is assumed to be as-available resources with a straight bus interconnection to the Palaau Power Plant for Molokai and Miki Basin Power Plant for Lanai, sited within five miles of the power plant. The size of conductor 336 AAC or 556 AAC depends on generation: for resources up to 10 MW, 336 AAC will be used; for resources above 10 MW, 556 AAC will be used.

Biomass

The analysis assumes that biomass is firm power sited within five miles of the Palaau Power Plant on Molokai and Miki Basin Power Plant on Lanai. A 336 AAC double circuit from 12kV interconnects the substation to the power plant.

Estimated Transmission Costs

Table 14-7. Molokai and Lanai Ten-Year Transmission Plan and Cost Estimates

Year	Project	Transmission Requirements	Estimated Costs
TBD	Wind	Interconnections and 5 miles 336 AAC or 556 AAC (see Table 14-16)	$2,250,000
TBD	Wave	Interconnections and 5 miles 336 AAC or 556 AAC (see Table 14-16)	$2,250,000
2018	Photovoltaics (PV)	Interconnections and 5 miles 336 AAC or 556 AAC (see Table 14-16)	$2,250,000
2018	Biomass	Interconnections and 5 miles 336 AAC double 69kV circuit (see Table 14-17)	$3,000,000

Note: Each upgrade contains a cross reference to a table that details cost breakdowns.

Cost Estimates for MECO

This section contains cost breakdowns for the MECO five-year and ten-year transmission upgrades.

Maui

The MECO Engineering Department prepared all cost estimates. Cost estimate for Maui assume $500,000 to add each breaker at developed substations, and $2.5 million per mile for dual 69kV overhead line work.

Table 14-8. Kaonoulu Substation Cost Estimates

Description	Cost
Kaonoulu Substation	$8,900,000
Kaonoulu Substation overhead feeder	$4,600,000
Kihei relay upgrade	$300,000
Maalaea relay upgrade	$300,000
Total	$14,100,000

Table 14-9. Maalaea-Kamalii 69 kV Line Cost Estimates

Description	Cost
Maalaea–Kamalii 69 kV line	$21,100,000
Kihei–Kamalii 69kV line	$1,200,000
Wailea–Kamalii 69kV line	$1,400,000
Kamalii Substation	$6,700,000
Maalaea Substation 69kV breaker addition	$1,000,000
Total	$31,500,000

Table 14-10. Waena Power Plant Phase I Cost Estimates

Description	Cost
Waena I switchyard	$7,700,000
Waena overhead transmission line	$800,000
Total	$8,500,000

Table 14-11. Waena Power Plant Phase II Cost Estimates

Description	Cost
Six breakers added to the WPP Substation	$3,000,000
Two-mile 556 AAC double circuit 69kV	$5,000,000
Total	$8,000,000

Table 14-12. Waena Power Plant Phase III Cost Estimates

Description	Cost
Five breakers added to the WPP Substation	$2,500,000
Total	$2,500,000

Table 14-13. Waiinu–Kanaha 69kV Conversion Cost Estimates

Description	Cost
Line work: conductors, poles, and other equipment	$16,400,000
Substation work (Waiinu, Kanaha, Kahului substations)	$ 12,200,000
Total	$28,600,000

Note: MECO Engineering estimates costs from the KPP Reduced Operation Study.

Table 14-14. Maui Geothermal Cost Estimates

Description	Cost
Geothermal interconnection substation	$7,000,000
Six breakers added at the interconnection substation	$3,000,000
Ten-mile 336 AAC double circuit 69kV to the geothermal substation	$25,000,000
Geothermal substation	$3,000,000
Total	$38,000,000

Table 14-15. Maui Biomass Cost Estimates

Description	Cost
Two breakers added at the WPP Substation	$1,000,000
0.5 mile 556 AAC circuit 69kV (WPP sub-biomass substation)	$600,000
Biomass substation	$3,000,000
Total	$4,600,000

Molokai and Lanai

The MECO Engineering Department prepared all cost estimates. Cost estimate for Molokai and Lanai assume $250,000 per mile for the overhead 12kV transmission lines (336AAC or 556AAC) and $361,000 per mile to reconductor a line for a Molokai and Lanai line crew with no mobilization cost (by MECO or an outside contractor).

Table 14-16. Molokai and Lanai Wind, Wave, and PV Cost Estimates

The interconnections and costs are the same for wind, wave, and PV.

Description	Cost
Power plant interconnection	$500,000
Five-mile 336 or 556 ACC 12kV transmission line	$1,250,000
Interconnection 12kV substation	$500,000
Total	$2,250,000

Table 14-17. Molokai and Lanai Biomass Cost Estimates

Description	Cost
Power plant interconnection	$750,000
Five-mile 336 AAC 12kV transmission line	$1,250,000
Interconnection 12kV substation	$1,000,000
Total	$3,000,000

HELCO Five-Year Transmission Planning Analysis

HELCO has developed potential transmission requirements for the most aggressive load growth over the next five years (2014 through 2023) as part of the 2013 IRP.

Planning Assumptions

HELCO has made certain assumptions and details regarding our transmission planning.

Five-Year Load Growth Assumptions

HELCO based its planning on load growth forecasts for the four IRP scenarios. These scenarios represent load growth under various assumptions that range from most aggressive load growth to most conservative load growth. As the load grows, HELCO plans to add new generation and transmission to reliably serve its customers.

HELCO's actual load in 2011 was 189 MW. The No Burning Desire scenarios projects the most aggressive load forecast for a 2018 peak load of 226 MW, thus increasing load by 37 MW.

New Generation Addition Assumptions

The analysis assumes that new generation will serve this potential load growth of 37 MW, all of which will be covered by adding the upcoming 2013 geothermal RFP for 50 MW. The transmission planning analysis is based on the geothermal location that creates the worst transmission constraints. A sensitivity analysis was performed to determine the effect of the location of the geothermal plant on the transmission system.

These load growth assumptions are summarized in Table 14-18.

Table 14-18. Five-Year Load and Generation for HELCO

Description	Load Growth
2011 actual peak load	189 MW
2018 load for the most aggressive load forecast	226 MW
Increase in load	37 MW
50 MW new generation addition	50 MW geothermal from 2013 RFP

The analysis included the following assumptions (summarized in Table 14-19 and Table 14-20):

115 MW of generation will be added in the model for 2033 aggressive load growth.

Table 14-20 contains a schedule for generation additions.

The first block of 50 MW will be added in 2022, which the Companies assume will be covered by the 2013 geothermal RFP.

- The second block of 50 MW will be added in year 2031.

Table 14-19. Twenty-Year Load and Generation for HELCO

Description	Load Growth
2011 actual peak load	189 MW
2033 load for the most aggressive load forecast	304 MW
Increase in load	115 MW

Table 14-20. Schedule of 50 MW Block of Generation Additions

Year	Load MW	MW Increase from 2013	Generation Additions
2013	200	10	
2014	206	17	
2015	214	24	
2016	212	23	
2017	219	29	
2018	216	27	
2019	226	37	
2020	231	42	
2021	236	47	
2022	241	52	50 MW; 2013 geothermal RFP
2023	247	58	
2024	253	64	
2025	259	70	
2026	265	76	
2027	270	81	
2028	276	86	
2029	281	92	
2030	287	97	
2031	292	103	Add new 50 MW generator
2032	298	109	
2033	304	114	

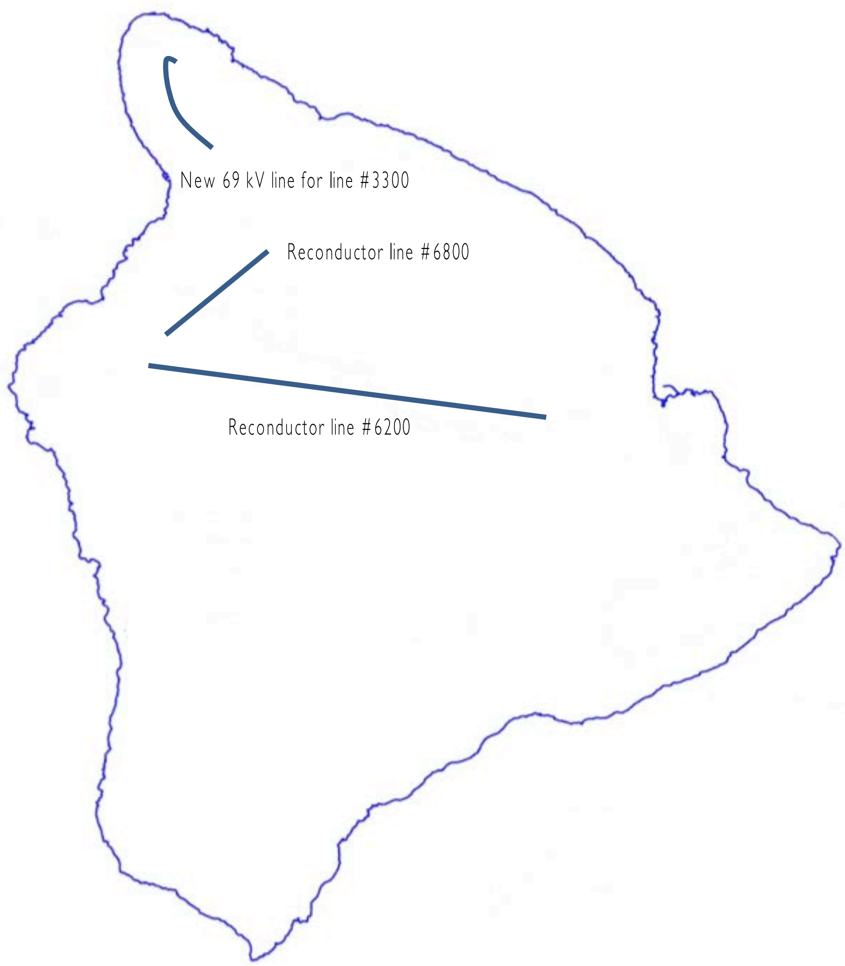
The transmission planning analysis depends on assumptions made about demographics, new generation locations, and renewable resource locations. Sensitivity analyses were performed to critically assess the effect of the following assumptions:

- Adding new generation in 50 MW blocks (with a power factor of ±0.80) to meet load growth. The Companies will have to add, at most, two generators: one located on the east side of the island and one located on the west side.
- Retiring generation replaced by similar generation at the same location.
- Upgrading transmission, including reconductoring line #6800 to increase its rating from 36 MVA to 70 MVA which will be completed by 2016–2017.

HELCO Five-Year Summary

Our five-year transmission plan requirements are depicted in Figure 14-5.

Figure 14-5. HELCO Five-Year Load Forecast, Generation Addition, and Transmission Plan



Reconductor Line #6800 and New 69kV Line Loop

Starting in 2013, HELCO plans to reconductor line #6800 (from the Keamuku 69 kV substation to the Keahole 69 kV substation) from 1/o copper to 556ACSR to alleviate overloading for N-1 conditions. There is also a plan to add a new 69 kV transmission line from the Waika substation to the Halauu station. The upgrade is estimated to cost $18 million.

The reconductoring is expected to be completed in 2016–2017 for a total estimated cost of $24.5 million over four phases. Phase 1 is expected to cost $6.2 million; phase 2, $6.9 million; phase 3, $7.5 million; and phase 4, $3.9 million.

Reconductor Line #6200

There is a plan to reconductor line #6200 (from the Kaumana 69 substation to the Keamuku 69kV substation) to 556 ACSR in 2015, and to complete the new geothermal construction.

There are two reasons to reconductor this line: to avoid a NERC Category D criteria violation and to account for transmissions from a future geothermal plant.

HELCO runs certain Keahole generators to serve the load on the west side of the Hawaii Island. If a severe NERC Category D outage occurs (the loss of a substation), then power must be transmitted from the east side of Hawaii. As a result, HELCO line #6200 as currently configured will overload.

A future 50 MW geothermal plant might be constructed on Hawaii's east side. HELCO line #6200 as currently configured will overload when transmitting power from this geothermal plant.

As with line #6800, it is expected that this reconductoring will be completed in 2016–2017 for a total estimated cost of $24.5 million over four phases. Phase 1 is expected to cost $6.2 million; phase 2, $6.9 million; phase 3, $7.5 million; and phase 4, $3.9 million.

Chapter 15: Assessing the Capacity Value of Wind

Accurately assessing the capacity value of wind is a critical component toward meeting customer demand and maintaining system reliability. Because wind is a variable resource, determining its capacity value becomes a considerable challenge in order to achieve the confidence required to commit wind resources to the grid to replace firm generation.

Maui's Wind Capacity Planning Criteria

The Companies must ensure that there is enough generating capacity to meet customer demand, plus enough generating capacity in reserve should demand suddenly increase or a generator or transmission line goes out of service. The variability of wind resources makes it critical to accurately assess its capacity value in order to better integrate wind power into the grid. Thus, each utility must apply its capacity planning criteria to all of its generating resources, but most especially to variable resources. For MECO, accurately evaluating the capacity value of its wind resources is critical.

Wind Capacity Analysis

MECO's capacity planning criteria for adding new generation is Rule 1[60]. MECO also employs a 20 percent reserve margin guideline for adding firm capacity resources. Due to its very nature, the capacity from variable resources (such as wind) is not counted as firm capacity in the calculation of Rule 1 nor the reserve margin guideline. For wind, this assumption is further supported by the historical data analysis of Maui's wind resources.

To determine the magnitude of the cost savings from deferring the need for future capacity, the Companies performed our analysis assuming a wind resource capacity value of 5%, as well as for its reserve margin. The 5% capacity value assigned to the wind resources was an arbitrary value used to estimate the potential capacity deferral benefit of a variable resource.

By giving capacity value to wind, the need for future firm resources was delayed in Blazing a Bold Frontier and Stuck in the Middle. Under Stuck in the Middle, it deferred the need date for a future 5 MW firm resource from 2023 to 2026, and eliminated the need for a future firm resource in 2027. Over the 50-year study period, the delay and elimination of future resources reduced total resource cost by almost $50 million. Table 15- compares resource plans and its costs that address wind capacity in Stuck in the Middle.

Under No Burning Desire, giving wind a 5% capacity value eliminated the need for a future 5 MW firm resource in 2015, which reduced the plan costs by almost $70 million over the 50-year study period. Table 15-2 compares resource plans and the wind capacity costs in No Burning Desire.

[60] Rule 1: 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.

The Companies did not model wind capacity value for Blazing a Bold Frontier because Rule 1 criteria violations were not experienced due to a declining sales and peak forecast. Therefore, future firm capacity resources were not required, which eliminated the wind's capacity deferral value in this scenario. Similarly for Moved by Passion, future firm capacity was not required, and therefore, the wind resources did not have any future firm resources to defer.

Table 15-1. Capacity Value of Wind Comparison: Stuck in the Middle

Name	**M2_2__X-2r11**	**M2B2a_X-8r3**
Plan	StiM Screen allow 5 MW ICE	SitM Capacity Value of Wind
Notes	Allow new ICEs (5 MW), Allow limited Wind, PV, Wave (Curtailed OK)	Allow ICEs, Geo, Biom, WTE, CT Allow Wind C7, TrPV, Wave (Curtailed OK)
Resources Available	10 MW Wind (MW04): 2015 1 MW PV (MP03): 2015 15 MW Ocean Wave (MV02): 2015 5 MW ICE (MS14): 2016	10 MW Wind (MW04): 2015 1 MW PV (MP03): 2015 15 MW Ocean Wave (MV02): 2015 17 MW ICE (MS01): 2016 5 MW ICE (MS14): 2016 21 MW CT (MS05): 2016 25 MW Geothermal (MG02): 2016 25 MW Biomass (MA01): 2017 8 MW WTE (MT01): 2017
DR & DSM Assumptions	75% of Base EEPS Fast DR Only	75% of Base EEPS Fast DR Only
2014		
2015	3x Wind (10 MW)	3x Wind (10 MW)
2016	3x Wind (10 MW)	3x Wind (10 MW)
2017	3x Wind (10 MW)	3x Wind (10 MW)
2018		
2019		
2020		
2021		
2022		
2023	ICE biofuel (5 MW)	
2024		
2025		
2026		ICE biofuel (5 MW)
2027	ICE biofuel (5 MW)	
2028		
2029		
2030	ICE biofuel (5 MW) 5x PV (1 MW)	ICE biofuel (5 MW) 5x PV (1 MW)
2031		

Name	**M2_2__X-2r11**	**M2B2a_X-8r3**
2032		
2033	5x PV (1 MW)	5x PV (1 MW)
Planning Total Cost	3,996,844	3,966,869
Study Total Cost	5,989,311	5,939,421
Planning Rank	2	1
Study Rank	2	1

Table 15-2. Capacity Value of Wind Comparison: No Burning Desire

Name	**M3_2a_N-2r4**	**M3B2a_N-8r0**
Plan	NBD Kahului Fuel Switch to LSIFO and Fuel Switch at Maalaea to S500 Diesel 2022	NBD 5% Wind Capacity Value
Notes	Firm Resource Timing on Rule 1, fixed from Unit Timing Run M3_2a_N-2r3, All DR, HC&S contract expires 12/31/2014 No Existing Unit Deactivations	Firm Resource Timing on Rule 1, Unit Timing Run M3_2a_N-2r4 as a guide All DR, HC&S contract expires 12/31/2014 Wind Resources Provide 5% Firm Capacity Value
Resources Available	10 MW Wind (MW04): 2015 1 MW PV (MP03): 2030 15 MW Ocean Wave (MV02): 2030 17 MW ICE (MS01): 2016 21 MW CT (MS05): 2016 25 MW Geothermal (MG02): 2016 25 MW Biomass (MA01): 2017 8 MW WTE (MT01): 2017	10 MW Wind (MW04): 2015 1 MW PV (MP03): 2015 17 MW ICE (MS01): 2022 5 MW ICE (MS14): 2015 21 MW CT (MS05): 2016 25 MW Geothermal (MG02): 2023 25 MW Biomass (MA01): 2023
DR & DSM Assumptions	75% of Base EEPS All DR: CIDLC Exp, RDLC Exp, Fast DR	75% of Base EEPS All DR: CIDLC Exp, RDLC Exp, Fast DR
2014		
2015	(3) 5 MW ICE; biofuel [MS14]	(2) 5 MW ICE; biofuel [MS14]
	(3) 10 MW wind [MW04]	(3) 10 MW wind [MW04]
2016	(1) 21 MW SC LM2500; biofuel [MS05]	(1) 21 MW SC LM2500; biofuel [MS05]
	(2) 10 MW wind [MW04]	(2) 10 MW wind [MW04]
2017		
2018	(1) 10 MW wind [MW04]	(1) 10 MW wind [MW04]
2019	(1) 21 MW SC LM2500; biofuel [MS05]	(1) 21 MW SC LM2500; biofuel [MS05]
		(1) 10 MW wind [MW04]
2020	(1) 10 MW wind [MW04]	
2021	(1) 10 MW wind [MW04]	(2) 10 MW wind [MW04]
2022	(1) 17 MW ICE; biofuel [MS01]	(1) 17 MW ICE; biofuel [MS01]
	(1) 10 MW wind [MW04]	
2023		
2024	(1) 17 MW ICE; biofuel [MS01]	(1) 17 MW ICE; biofuel [MS01]
2025		
2026		
2027	(1) 25 MW new geothermal [MG02]	(1) 25 MW new geothermal [MG02]
2028		
2029		
2030		
2031	(1) 17 MW ICE; biofuel [MS01]	(1) 17 MW ICE; biofuel [MS01]
2032		
2033		

Name	M3_2a_N-2r4	M3B2a_N-8r0
Planning Total Cost	4,792,560	4,734,182
Study Total Cost	7,068,077	6,998,552
Planning Rank	2	1
Study Rank	2	1

Historical Data Analysis

Before assigning a capacity value to a variable generating resource, evaluation of historical capacity availability and probabilistic analyses are required to ensure confidence in variable resource availability and system reliability. Numerous published documents on the various methodologies used by utilities or state and regional independent studies offer some guidance in determining the capacity value of wind in their respective areas.[61] The reports indicate that the capacity value of wind can be as low as 0% (Bonneville Power Administration, Nebraska Public Power District, NorthWestern Energy) or greater than 30% (Eastern Wind Integration and Transmission Study, Hydro-Quebec, New York ISO, Portland General).

Because emergency power cannot be purchased from neighboring entities (as done on the mainland), the Companies must carefully examine the capacity value allocated to variable generation to ensure continued reliability. Existing standards from the mainland cannot be directly applied to Hawaii. To ensure quality power is available from wind resources to meet system demand, the Companies must err on the side of caution until the capacity value of the variable generation can be confidently determined.

Evaluating historical wind data and system load provides a measure of that confidence. The higher the availability of wind during system peaks will lead to higher capacity values assigned to the wind. Conversely, lower availability will lead to lower capacity values. For these types of historical analyses, the Institute of Electrical and Electronics Engineers (IEEE) suggests "that at least four years of data in hourly resolution are necessary for reliable studies…" as it pertained to their wind power generation analysis in Ireland.[62] In the NREL studies, historical data collection for use in determining wind capacity value ranged from 3 to 12 years.

The Maui system currently has three wind farm resources:

- Kaheawa Wind Power, LLC (KWP): 30 MW (in-service date June 2006)
- Kaheawa Wind Power II, LLC (KWP2): 21 MW (in-service date June 2012)
- Auwahi Wind Energy, LLC (Auwahi): 21 MW (in-service date December 2012)

These three units are examined in the following sections.

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[61] Summary of Time Period-Based and Other Approximation Methods for Determining the Capacity Value of Wind and Solar in the United States; September 2010–February 2012 by the National Renewable Energy Laboratory (NREL).
Determining the Capacity Value of Wind: A Survey of Methods and Implementation by NREL

[62] Capacity Value of Wind Power: Calculation and Data Requirements

Kaheawa Wind Power Analysis

KWP has approximately six years of historical data, while KWP2 and Auwahi have less than one year of historical data. Only KWP has a reasonable amount of data for assessing wind to system load. Table 15-3, then, shows the Maui instantaneous monthly system peak and the associated wind generation coincidence at KWP. The KWP output is shown as a percentage of its 30 MW rated capacity at the 15 minute recorded interval near to the Maui system instantaneous peak. The data highlighted in orange indicates when the Maui annual system peak occurred.

Table 15-3. KWP Wind Generation Coincidence with Maui Peak

Date	Time	MECO Gross System Peak (MW)	KWP Output
26-Jun-2006	19:46	199.9	1%
31-Jul-2006	19:45	207.5	0%
14-Aug-2006	19:33	210.8	12%
15-Sep-2006	19:14	201.2	2%
9-Oct-2006	18:57	210.7	0%
6-Nov-2006	18:36	210.4	1%
27-Dec-2006	18:41	210.6	0%
22-Jan-2007	18:50	203.3	0%
1-Feb-2007	18:54	200.7	50%
7-Mar-2007	19:11	200.6	0%
11-Apr-2007	19:27	195.7	0%
21-May-2007	19:34	201.1	0%
26-Jun-2007	19:44	197.9	43%
2-Jul-2007	19:49	201.4	27%
13-Aug-2007	19:26	207.0	87%
17-Sep-2007	18:59	201.9	96%
22-Oct-2007	18:31	203.4	18%
7-Nov-2007	18:35	209.3	22%
3-Dec-2007	18:31	198.3	30%
9-Jan-2008	18:43	199.0	0%
20-Feb-2008	19:08	197.4	0%
10-Mar-2008	19:15	196.4	0%

Date	Time	MECO Gross System Peak (MW)	KWP Output
8-Apr-2008	19:24	191.5	0%
19-May-2008	19:33	191.2	70%
30-Jun-2008	19:51	192.9	0%
22-Jul-2008	19:47	196.1	100%
4-Aug-2008	19:31	194.3	98%
29-Sep-2008	18:51	188.8	0%
27-Oct-2008	18:33	193.6	1%
12-Nov-2008	18:25	192.0	0%
30-Dec-2008	18:45	192.6	40%
15-Jan-2009	18:44	188.1	100%
10-Feb-2009	18:59	184.3	0%
9-Mar-2009	19:08	181.6	0%
20-Apr-2009	19:29	177.2	0%
26-May-2009	19:34	188.7	1%
16-Jun-2009	19:36	188.9	10%
23-Jul-2009	19:43	194.6	0%
13-Aug-2009	19:21	196.2	0%
22-Sep-2009	19:05	190.1	0%
21-Oct-2009	18:39	204.3	0%
2-Nov-2009	18:38	191.3	33%
29-Dec-2009	18:33	199.5	19%
6-Jan-2010	18:41	192.8	0%
1-Feb-2010	18:49	190.0	0%
29-Mar-2010	19:15	183.4	92%
6-Apr-2010	19:21	188.5	0%
3-May-2010	19:22	183.7	0%
28-Jun-2010	19:47	184.7	22%
27-Jul-2010	19:49	187.1	0%
12-Aug-2010	19:33	188.7	95%
27-Sep-2010	18:54	188.3	0%
21-Oct-2010	18:38	198.3	0%
9-Nov-2010	18:25	190.7	0%
28-Dec-2010	18:32	203.8	0%
12-Jan-2011	18:40	188.9	100%
17-Feb-2011	19:02	194.1	0%

Date	Time	MECO Gross System Peak (MW)	KWP Output
3-Mar-2011	19:06	186.7	11%
18-Apr-2011	19:17	187.8	0%
12-May-2011	19:22	181.8	8%
6-Jun-2011	19:31	176.7	0%
25-Jul-2011	19:36	183.5	3%
8-Aug-2011	19:43	185.0	50%
15-Sep-2011	19:11	188.4	9%
24-Oct-2011	18:38	189.6	0%
14-Nov-2011	18:31	189.4	0%
28-Dec-2011	18:36	189.3	93%
4-Jan-2012	18:37	192.9	3%
13-Feb-2012	19:07	186.0	0%
19-Mar-2012	19:25	182.5	0%
2-Apr-2012	19:10	184.6	0%
1-May-2012	19:28	174.0	95%
13-Jun-2012	19:44	175.9	1%
30-Jul-2012	19:36	181.9	95%
20-Aug-2012	19:35	186.5	22%
20-Sep-2012	18:59	177.9	0%
25-Oct-2012	18:36	193.3	0%
19-Nov-2012	18:31	187.5	0%
31-Dec-2012	18:29	199.1	5%
2-Jan-2013	18:37	189.8	95%
11-Feb-2013	19:02	179.7	83%
21-Mar-2013	19:08	181.2	0%

Table 15-3 shows that KWP did not provide any generation 41 out of the 82 monthly system peak periods. In other words, from the in-service date of KWP through the first quarter of 2013, KWP was unable to provide energy to the Maui system fifty percent of the time when the monthly system peak occurred.

KWP Wind Generation Coincidence

The KWP historical data coincidence with the system peak load can also be measured over hourly periods. From January 2007 to December 2012, there were 2,192 hours where the average load was the highest for each day. Over those same hours, the average KWP wind generation was recorded. There were 405 times where KWP did not produce energy and 265 times where KWP provided generation greater than 0 MW and less than or equal to 1.5 MW. Table 15-4 shows the number of occurrences and the associated amount of average wind generation during the daily average peak hour period.

Table 15-4. Daily Hourly Average KWP Wind Generation Coincidence with Daily Maui Hourly Average Peak

% Wind Generation	Wind Capacity Range (MW)	Number of Occurrences	% Occurrence
0%	0	405	18.5%
5%	0.1–1.5	265	12.1%
10%	1.6–3.0	69	3.1%
15%	3.1–4.5	41	1.9%
20%	4.6–6.0	50	2.3%
25%	6.1–7.5	30	1.4%
30%	7.6–9.0	33	1.5%
35%	9.1–10.5	27	1.2%
40%	10.6–12.0	25	1.1%
45%	12.1–13.5	29	1.3%
50%	13.6–15.0	36	1.6%
55%	15.1–16.5	36	1.6%
60%	16.6–18.0	35	1.6%
65%	18.1–19.5	39	1.8%
70%	19.6–21.0	49	2.2%
75%	21.1–22.5	53	2.4%
80%	22.6–24.0	63	2.9%
85%	24.1–25.5	85	3.9%
90%	25.6–27.0	117	5.3%
95%	27.1–28.5	191	8.7%
100%	28.6–30.0	514	23.4%

Table 15- shows that if KWP were relied upon to provide generation in the hour that the average daily peak occurred, there could have been 405 instances where KWP would have failed to provide anticipated generation and could have placed the system at risk. Further, if KWP had been provided

a capacity value of 10% of its rated capacity (3.0 MW), then it is possible that there could have been approximately 739 incidents where KWP would not have been able to provide capacity for the required system demand.

From a reliability perspective, the system requires enough generating capacity to satisfy the system demand for power to ensure that all customers' electricity needs are met. The historical generation of KWP does not provide confidence that power would be provided when the system required it. The confidence of a resource's ability to provide generation is not only considered during the times when the system peak occurs, but is also relied on to provide power when other firm generating resources are not available due to scheduled maintenance or unforeseen outage conditions.

Capacity Value from Three Wind Resources

Although there is not enough historical data for KWP2 or Auwahi, MECO and Hawaiian Electric attempted to determine an aggregated capacity value (or effective load carrying capability) for all three wind resources.[63] The two utilities employed a methodology known as loss of load expectation (LOLE).[64] The two utilities used the PREL algorithm in the PMonth software to calculate the loss of load probability (LOLP, which is also referred to as LOLE). The hourly wind profiles for each of the three wind farms were based on the following:

- KWP: historical data used to make a forward projection
- KWP2: KWP historical data proportioned to the KWP2 capacity rating of 21 MW
- Auwahi: AWS True Wind developed wind profile based on 2007 metrological data

The LOLP calculation resulted in an aggregated capacity value of all three wind farms ranging from 4.5% to 13.4%. The analysis of the wind input data, however, requires several improvements:

- KWP and KWP 2 have the same hourly profile shapes. This indicates that the two wind farms have the same wind regimes which may not reflect actual conditions.
- The Auwahi wind profile is based on only one year of metrological data which does not accurately represent the wind variability from year to year.

The two utilities require a minimum of four years of historical data to perform more analyses before assigning a capacity value to the existing wind farms on Maui. Four years actual wind data from each wind farm will provide:

- Wind diversity assessment.
- Coincidence of wind generation and system load, and more importantly, peak correlation.
- Increased confidence in probabilistic calculations.

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[63] Per IEEE, capacity value designates the contribution of a power plant to the generation adequacy of the power system. It gives the amount of additional load that can be served in the system at the same reliability level due to the addition of the unit.

[64] Per IEE, the loss of load expectation is a measure of system adequacy and nominates the expectation of a loss of load event.

Currently, MECO and the wind farms are working together to record wind data to build a database. The data being collected and recorded includes, but are not limited to:

- Wind generation delivered to the Maui system.
- Estimated potential wind generation based on wind speed converted to capacity (MW)/energy (MWh).
- Curtailed wind generation.
- System regulating reserve.
- KWP2 battery energy storage system (BESS) operation.

With four years of actual wind data, the two utilities should be able to determine a reasonable wind capacity value. Confidence in wind capacity value will enable the utilities to count a portion of the as-available wind generation resources toward system reliability, which in turn, have the potential to defer firm capacity generation installations.

Chapter 16: Integrating High Penetration of Variable Distributed Generation

Distributed generation (DG) installations on the islands have increased rapidly over the last five years. Customers that installed DG, particularly rooftop photovoltaic (PV) systems, have enjoyed the direct benefits from these installations, and these installations have helped contribute to the achievement of RPS goals. The Hawaiian Electric Companies consistently rank among the top utilities in the nation as far as installed PV per customer. As more distributed PV is added, however, it is becoming more challenging to safely and reliably integrate the systems into the electric grid and to maintain fair electric rates to all customers.

To overcome these challenges and enable distributed PV to continue to grow, the Company proposes to study, develop, and implement technical solutions for high penetration of distributed generation; standardize interconnection processes and practices; and fully support PUC proceedings to review policies, programs, and rules for the best interests of all customers.

Addressing Technical Distributed Generation Integration Issues

The installation of distributed renewable energy generation has experienced rapid growth in the past five years. Solar PV has seen the most substantial growth of all renewable technologies on all islands in Hawaii. The high costs of electricity in the State of Hawaii along with the availability of Federal and State tax credits, more competition in the solar industry, varied financing options for customers, and lower equipment costs have all contributed to making installation of PV systems more affordable and attractive to Hawaii consumers. Distributed PV has played a significant role in moving the Hawaiian Electric Companies closer to achieving its renewable energy goals.

However, with this aggressive growth in distributed PV, distribution circuits across the islands are steadily "filling" in terms of the amount of installed PV that can be accommodated while maintaining safe and reliable electric service. On each island, some distribution circuits have reached the point where the amount of installed and planned PV exceeds the circuits' daytime minimum loads. When the aggregate PV capacity is greater than 100% of minimum load, this could result in power flow from the generating facilities back toward the substation, negatively impacting equipment loading, voltage, system operational impacts, and protection of the Company's system. On these circuits, interconnection studies and upgrades will be required to meet circuit-level safety standards and ensure compliance with tariff rules. By current utility rules approved by the PUC, interconnecting DG customers are responsible for the costs of such studies and circuit upgrades.

At the island-wide electric system level, as more variable and intermittent energy sources are connected to the grid, electric system operators will be challenged to maintain the perfect balance between energy production and energy usage that is necessary to provide stable and reliable service to customers. System upgrades will be necessary to allow the flow of power to and from distributed generators as well as to allow greater coordination and supervision to balance supply and demand — all to ensure continued grid reliability.

The Companies plan to proactively conduct regional impact studies and circuit level interconnection requirements studies to determine the physical limitations of the current systems, and identify opportunities to facilitate the continued build-out of distributed generation. For its regional analyses, Hawaiian Electric plans to implement what has been proposed as the "Proactive Approach" in the Reliability Standards Working Group (RSWG) proceeding, PUC Docket No, 2011-0206. As described in the PV-Subgroup's Final Report filed in this Docket:

> HECO will utilize the interconnection queue and other data points to establish a reasonable base case of anticipated DG development. Through its

> distribution and transmission planning effort, it will proactively plan for the aggregate system impacts from expected DG development in order to accommodate higher penetration levels. The coordination of interconnection and planning will identify opportunities where infrastructure upgrades can accommodate both DG and load such that a number of generators and customers can benefit from the upgrades.
>
> Specifically, HECO will employ enhanced tools for modeling DG to inform both system and distribution-level planning and operations. Those models will leverage PV production data from individual DG systems, which members of the PV industry recently made available to HECO, to supplement utility monitoring tools. This improved modeling capability will, in turn, enhance a number of areas related to the interconnection of high penetrations of DG, including:
>
> - Assessing potential system and region-level impacts due to high penetrations;
> - Evaluating impacts lo dispatch and generation, reserve planning, and response to ramping events:
> - Informing and streamlining the distribution level interconnection process; and
> - Helping to identify circuit penetration capabilities, potential issues, and necessary upgrades.
>
> The overall goal of this collaborative approach is to create a more transparent and efficient process for interconnecting higher levels of DG while maintaining safety, reliability, and power quality across the transmission and distribution infrastructure. The approach will benefit all parties involved, including customers, developers and utilities, as well as the broader public. (PV Sub-Group Final Report, Docket No. 2011-0206, pages 14-15)

Based on these regional and circuit-level analyses, each company will complete circuit upgrade projects. The costs of the studies and upgrades will be allocated to those customers with current requests to interconnect, and to future interconnecting customers. This allocation of costs will benefit PV customers by spreading the financial burden of studies and upgrades across a larger number of participants. This proactive approach will support the continued growth of PV, ensure safety and reliability, and help reduce the financial burden and time duration for DG customers to interconnect.

In addition, the Companies will standardize their implementation of interconnection processes and support additional PUC reviews of interconnection tariffs, in order to adopt best practices, address technical issues, enable new distributed generation customers to interconnect into the future, and address customer equity issues.

Improve Fairness and Consistency of Current Policies, Programs, and Rules

The rapid growth of customer-sited PV has highlighted a number of potential impacts on non-distributed generation customers, independent power producers (IPPs), and future distributed generation customers. The Companies' goal is to continue to support the growth of distributed PV while addressing these issues, in order to assure the provision of safe, reliable electricity at an affordable price for all of the Companies' customers.

The RSWG reviewed a number of these issues in Docket No. 2011-0206. The following are selected recommendations and comments of the RSWG Independent Facilitator to the PUC regarding fairness issues associated with the growing amounts of PV:

> In its final report, the PV subgroup raises a number of equity and cost allocation issues (between DG owners and between DG owners and the utility and its ratepayers) in addition to pure process/technical issues. It might be feasible to handle the equity and cost allocation issues in a new multi-stakeholder process similar to the RSWG to gain a faster resolution than might be possible through a formal rulemaking. (Reliability Standards Working Group Independent Facilitator's Submittal, Final Report, filed March 25, 2013 in Docket No. 2011-0206, page 29)

> As the HSIS points out, growing levels of rooftop PV are rapidly changing the utility customers' load profile while reducing total system energy demand. This will cause cannibalization between small PV and big wind as follows: under current regulations, small PV will be able to operate without curtailment (and thus will impose greater requirements for peak capacity and ancillary services), but (absent aggressive energy storage or DR requirements at the customer/feeder) increasing levels of intermittent PV will place greater demands on central station minimum load operation to effectively integrate and backstop the growing levels of PV. This will in turn force higher levels of curtailment of wind generation (absent great improvements in the ability of new and current wind generation to provide the ancillary services and capacity now delivered by dispatchable central station generation). Consider starting a new collaborative process that addresses the technical, equity and policy implications of this issue, to anticipate and develop possible regulatory solutions for this challenge. (Reliability Standards Working Group Independent Facilitator's Submittal, Final Report, filed March 25, 2013 in Docket No. 2011-0206, page 31)

> As the amount of installed rooftop PV grows within Hawaii, it is creating significant economic cost transfers between groups of Hawaii's citizens. These include the fact that Hawaii taxpayers are providing tax credit subsidies for new PV that do not accrue to non-PV owners; the feeder upgrade and

> operational requirements that increasing levels of PV impose upon utility customers; and as more PV owners (often more affluent citizens) generate their own energy, they leave fewer customers remaining on the utility system to pay for the fixed capital and operational non-energy costs of system operations. Overall, there are a number of inter-related equity issues relating to the impacts of growing PV upon Hawaii's citizens, and it may be useful to open another collaborative proceeding to explore these issues and develop recommendations for how to address them fairly and constructively before levels of PV grow even higher. (Reliability Standards Working Group Independent Facilitator's Submittal, Final Report, filed March 25, 2013 in Docket No. 2011-0206, page 31)

The RSWG follow-on dockets under consideration by the PUC would be an appropriate forum to address the interconnection and customer equity issues related to the interconnection of DG resources. The Companies will fully participate in these dockets.

In addition, the PUC has contracted a third-party consultant to review the effectiveness of existing programs such as Net Energy Metering, Standard Interconnection, Feed-in-tariff, and PPAs. This review, to be completed in 2013, will assess energy procurement costs, progress toward meeting the State's renewable energy goals, administrative costs and ease of process, and fairness and equity across customer classes. The Companies have provided information to support the PUC's review, and will consider potential revisions to its procurement programs to improve their cost effectiveness and fairness for all customers.

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Chapter 17: Advisory Group Qualitative Metric Considerations

The Advisory Group played an integral role throughout the IRP process in regards to defining the qualitative metrics to be considered by the Companies' in their analyses. The two matrices of qualitative metrics, as edited by the Independent Entity, reflect the cumulative considerations of all Advisory Group members who participated in a work session on 17 April, 2013, and their comments submitted during the subsequent two weeks. The Independent Entity organized the work session by island teams: one team representing each of the five islands served by the Companies. Advisory Group members had the opportunity to select the Island team that they wanted to represent.

Introduction

The qualitative metrics, as defined by the Advisory Group, identify many of the challenges and impacts associated with implementing any new resource which must be mitigated and addressed before development can occur. The descriptions of qualitative considerations for the various resource options and plan elements were applied to the Draft Action Plan to help inform the Company of potential impacts. Many of the considerations, however, would best be assessed during the process of identifying and selecting specific resource options. Many of the qualitative metric considerations are project specific. As such, impacts would apply to siting (visual, cultural, and environmental impacts), resource size and location, type of resource (land use, cultural sensitivity toward geothermal), and community values (customer fairness and inequities such as the affordability of solar by all customers).

These metrics will continue to guide the Company's decision making process beyond the 2013 Integrated Resource Planning process. For example, in Chapter 5 of the latest draft of the Requests for Proposals (RFP) for Renewable Energy and Undersea Cable System Projects Delivered to the Island of Oahu, some of the elements of the qualitative metrics in the non-price evaluation criteria (community outreach plans, cultural resource impacts, environmental compliance, and others) are described as evaluation factors. The Company intends to make the qualitative metric considerations an integral part in future RFPs for developers to address in their development of their project proposals. RFP selection criteria for future resources will include evaluation of qualitative metric considerations. Therefore, even though the Action Plan and resource plans include the resources stated here, there is no certainty that they can be implemented because of these factors.

All-Island Qualitative Metric Considerations

Table 17-1. All-Island Qualitative Metric Considerations

Environment	Culture	Community Values	Other	Utility System
Generally Applicable Concerns				
It is important that the environment is not degraded, specifically considering: Whale sanctuary; Endangered species (flora and fauna); impacts of maintenance, decommissioning and disposal	It is important that cultural values and practices are supported, specifically considering: Cultural practitioner access and beliefs; Fishing; Hunting; Gathering rights	It is important that community values are supported, specifically considering: Respect for public opinion; Local job impacts; Safety; Reliability; Health	It is important to consider location-specific impacts, specifically including: Property values; Recreation resources	
Wind: Small Scale Onshore (<10 KW)				
–/o Visual Impact: obstruction of view planes & aesthetics (depends on size and location) – Hazards to birds, wildlife	– Potential proximity to culturally sensitive areas	– Visual Impact: obstruction of view planes & aesthetics (depends on size and location)		
Wind: Medium Scale Onshore (<5MW)				
–/o Visual Impact: obstruction of view planes & aesthetics (depends on size and location); Blinking red lights at night – Hazards to birds, wildlife	– Potential proximity to culturally sensitive areas	– Visual Impact: obstruction of view planes & aesthetics (depends on size and location)		

Environment	Culture	Community Values	Other	Utility System
Wind: Large Turbine Onshore				
– Visual Impact: obstruction of view planes & aesthetics (depends on size and location); Blinking red lights at night –/o Impacts depend on location –/o Hazards to birds, wildlife	– Potential proximity to culturally sensitive areas – Restrictions to gathering areas –/o Impacts depend on location	– Visual Impact: obstruction of view planes & aesthetics (depends on size and location) – (Lanai) Restrictions on access to hunting and fishing areas –/o Impacts depend on location	– (Lanai) Community opposition could prevent or delay implementation	– Competes with smaller resources for available grid/circuit capacity
Wind: Offshore (Ocean) Turbines				
–/o Visual Impact: obstruction of view planes & aesthetics (depends on size and location) – Hazards to whale migration, fish, birds, etc. – Reef Impact: damage from cable laying and directional drilling – EMF impacts on sea-life – Onshore termination: land impacts, land use, visual impacts for onshore conversion stations –/o Impacts depend on location	– Potential proximity to culturally sensitive areas –/o Impacts depend on location	– Visual Impact: obstruction of view planes & aesthetics (depends on size and location) –/o Impacts depend on location	–/o May pose safety / navigational hazard	– Competes with smaller resources for available grid/circuit capacity

Environment	Culture	Community Values	Other	Utility System
Wind: "Big Wind" — Lanai (w/ Undersea Cable)				
– Visual Impact: obstruction of view planes & aesthetics – Hazards to birds, wildlife – Whale habitat: dangers posed by cable laying ships and submerged cable – Reef Impact: damage from cable laying and directional drilling – EMF impacts on sea-life – Onshore termination: land impacts, land use, visual impacts for onshore conversion stations	– Turbine location known to contain culturally sensitive areas	– Visual Impact: obstruction of view planes & aesthetics (depends on size and location)		– Competes with smaller resources for available grid/circuit capacity
Solar Photovoltaic: Residential				
		– Inequity: participation limited to higher income customers + Creation of local, green jobs; support for small businesses	– Disreputable business practices need to be mitigated by consumer protection measures – Obstacles and delays in interconnection to utility under present rules	– Obstacles and delays in interconnection to utility under present rules
Solar Photovoltaic: Large Rooftop (100 KW)				
		– Inequity: participation limited to higher income customers + Creation of local, green jobs; support for small businesses	– Disreputable business practices need to be mitigated by consumer protection measures – Obstacles and delays in interconnection to utility under present rules	– Competes with smaller resources for available grid/circuit capacity
Solar Photovoltaic: Ground Mounted (1 MW)				
– Land requirements compete with other uses + Potential productive use of non-arable land	o/– Potential proximity to culturally sensitive areas	+ Creation of local, green jobs; support for business		– Competes with smaller resources for available grid/circuit capacity

Environment	Culture	Community Values	Other	Utility System
Solar Thermal (Trough 50 MW)				
− Land requirements compete with other uses + Potential productive use of non-arable land	o/− Potential proximity to culturally sensitive areas	+ Creation of local, green jobs; support for business		− Competes with smaller resources for available grid/circuit capacity
Geothermal				
− Potential leakage of noxious gases − Noise and health concerns in near proximity	− Potential proximity to culturally sensitive areas − Affects cultural values: respect for Pele + Affects cultural values: gift from Pele	− Noise and health concerns in near proximity		−/+ Requires new transmission installations − Generation reliability risk: geologically unstable source locations
Ocean Wave: Offshore Generation				
−/o Visual Impact: obstruction of view planes & aesthetics (depends on size and location) − Hazards to whale migration, fish, birds, etc. − Reef Impact: damage from cable laying and directional drilling − EMF impacts on sea-life − Onshore termination: land impacts, land use, visual impacts for onshore conversion stations	− Potential proximity to culturally sensitive areas	− Visual Impact: obstruction of view planes & aesthetics (depends on size and location)	−/o May pose safety / navigational hazard	
Ocean Thermal Energy Conversion				
− Reef Impact: damage from cable laying and directional drilling − EMF impacts on sea-life − Onshore termination: land impacts, land use, visual impacts for onshore conversion stations	− Potential proximity to culturally sensitive areas			

Environment	Culture	Community Values	Other	Utility System
Biomass Combustion				
+ Productive/sustainable use of agricultural lands − Air quality/pollution from combustion by products + Possible air quality improvement from reduction in existing field burning − Water requirements (depends upon cooling technology) − Contamination from pesticides	− Potential proximity to culturally sensitive areas	+ Sustainable agricultural activities + Sustainable job creation + Preservation of open space		
Waste-to-Energy (Municipal Solid Waste Mass Burn)				
+ Reduction in landfill volume − Residual combustion solid waste disposal impacts − Air quality/pollution from combustion by products o/− Water requirements (depends upon cooling technology) o/− Potential groundwater contamination	− Potential proximity to culturally sensitive areas	o/– Potential groundwater contamination	o/− Relies on maintaining waste streams: contrary to waste reduction strategies	
Fuel Cells: Utility Scale				
+ Clean use of fuels — no noxious emissions − Potential contamination from phosphorus − Fuel supply and storage infrastructure impacts	− Potential proximity to culturally sensitive areas	− Potential fire hazard		

Environment	Culture	Community Values	Other	Utility System
Battery Energy Storage: Utility Scale				
− Large land use footprint − Potential chemical contamination	− Potential proximity to culturally sensitive areas	− Potential fire hazard	+ Sustainable job creation	+ May be robust way to enable demand response resource + Provides ancillary services for utility system
Internal Combustion Engines: Utility Scale				
− Produces air emissions + Used as replacement for existing units can increase efficiency and reduce air emissions	− Potential proximity to culturally sensitive areas			+ Provides ancillary services for utility system + Flexibility in switching fuels
Combustion Turbines				
− Produces air emissions + Used as replacement for existing units can increase efficiency and reduce air emissions	− Potential proximity to culturally sensitive areas			+ Provides ancillary services for utility system + Flexibility in switching fuels
Deactivation / Retirement of existing generation units				
− Issues and land use impacts associated with remediation + Restoration of land for other uses		− Loss of jobs (electric utility personnel)	+ Supports a portfolio approach to system planning; begets trust	
Repowering Existing Generation Units				
−/+ Continues but reduces air emissions + Used as replacement for existing units can increase efficiency and reduce air emissions				
Fuel Switching: USLD and LSFO				
− Continued impacts on air, land and water + Improved air quality impacts: meets new environmental regulations		− Continued dependence on importing fuels	− Non-renewable fuel: does not help meet clean energy goals	

Environment	Culture	Community Values	Other	Utility System
Fuel Switching: Locally Produced Biofuels				
+ Improved air quality impacts: meets new environmental regulations + Productive use of agricultural lands − Competes with food production use of land and water resources − Impacts of fertilizers and pesticides	− Potential proximity to culturally sensitive areas	+ Creation of local, green jobs; support for business − Social stress: projects may "split" communities regarding support or opposition −/+ Effects on existing agricultural operations	+ Does not require long-distance ocean transport − Requires local transport of biofuels −/o Depends on availability and persistence of fuel source	
Fuel Switching: Imported Biofuels				
+ Improved air quality impacts: meets new environmental regulations − Environmental impacts associated with production and processing prior to import		− Continued dependence on importing fuels	− Requires long-distance ocean transport	
Fuel Switching: Liquefied Natural Gas				
+ Improved air quality impacts: meets new environmental regulations − Impacts associated with necessary infrastructure − Environmental impacts associated with production and processing prior to import: "fracking" and associated chemical use/contamination	− Potential proximity of infrastructure to culturally sensitive areas	− Continued dependence on importing fuels but with potential domestic sourcing − Potential safety concerns with port facilities and storage		+ Abundant source: no peak determined

Environment	Culture	Community Values	Other	Utility System
Undersea Transmission Cable				
− Whale habitat: dangers posed by cable laying ships and submerged cable − Reef Impact: damage from cable laying and directional drilling − EMF impacts on sea-life − Onshore termination: land impacts, land use, visual impacts for onshore conversion stations −/o Impacts depend on location	− Potential proximity to culturally sensitive areas	− Onshore termination: land impacts, land use, visual impacts for onshore conversion stations −/+ Restrictions on fishing can provide/promote sanctuary −/o Impacts depend on location		
Transmission and Distribution Installations				
− Visual impacts for overhead T&D − Concerns regarding EMF emissions	− Potential proximity of infrastructure to culturally sensitive areas	− Visual impacts for overhead T&D − Concerns regarding EMF emissions + Can provide robustness in civil defense and disaster response		+ Can improve power quality + Can provide improved civil defense and disaster response
Advanced Metering / Smart Grid				
− Concerns regarding EMF emissions		− Privacy / Security: personal information at risk; intrusion − Loss of jobs (electric utility personnel)		

Lanai Qualitative Metric Considerations

Table 17-2. Lanai Qualitative Metric Considerations

Environment	Culture	Community Values	Other	Utility System
Wind: Small Scale Onshore (<10 KW)				
−/o Visual Impact: (depends on size, number and location) − Hazards to birds − Decommissioning is a detriment unless provisions are guaranteed by contract	− Potential proximity to culturally sensitive areas	−/o Visual Impact: (depends on size, number and location) + Local jobs −/o Fishing and hunting: depends on whether access to shoreline and hunting areas is restricted −/o Public opinion depends upon size, location and bill impacts		
Wind: Medium Scale Onshore (<5MW)				
−/o Visual Impact: (depends on size, number and location) − Hazards to birds and bats − Decommissioning is a detriment unless provisions are guaranteed by contract	− Potential proximity to culturally sensitive areas	−/o Visual Impact: (depends on size, number and location) + Local jobs −/o Fishing and hunting: depends on whether access to shoreline and hunting areas is restricted −/o Public opinion depends upon size, location and bill impacts	− Other impacts include: magnetic source, health, societal stress, safety and agriculture.	

Environment	Culture	Community Values	Other	Utility System
Wind: Large Turbine Offshore				
− Not applicable to Lanai utility system but, if located on Lanai would have negative impacts including: visual, wildlife, decommissioning, avian, hunting, fishing, noise and light pollution, magnetic source, health, environmental.	− Potential proximity to culturally sensitive areas	− Not applicable to Lanai utility system but, if located on Lanai would have negative impacts including: visual, wildlife, decommissioning, avian, hunting, fishing, magnetic source, health, local jobs, social stress, public opinion, safety and agriculture.	− Community opposition could prevent or delay implementation	
Wind: Offshore (Ocean) Turbines				
Not applicable to Lanai utility system but, if located off-shore could negatively impact fishing	Not applicable to Lanai utility system	Impacts can't be assessed without knowing size and location		
Wind: "Big Wind" — Lanai (w/ Undersea Cable)				
− Not applicable to Lanai utility system but, if located on Lanai would have negative impacts including: visual, wildlife, decommissioning, avian, hunting, fishing, noise and light pollution, magnetic source, health, environmental.	− Not applicable to Lanai system but if located on Lanai would impact culturally sensitive areas	− Not applicable to Lanai utility system but, if located on Lanai would have negative impacts including: visual, wildlife, decommissioning, avian, hunting, fishing, magnetic source, health, local jobs, social stress, public opinion, safety and agriculture.	− Community opposition could prevent or delay implementation	
Solar Photovoltaic: Residential				
+ Visual + Wildlife + Decommissioning + Avian + Environmental		+ Local jobs	+ This is ideal solution requested by Lanai residents, assuming circuit capacity	

Environment	Culture	Community Values	Other	Utility System
Solar Photovoltaic: Large Rooftop (100 KW)				
+ Visual + Wildlife + Decommissioning + Avian + Environmental		− Inequity: participation limited to commercial customers & would limit access on circuits to residential + Short term creation of local, green jobs	− Installations by off-island installers: potential disreputable business practices	− Competes with smaller resources for available grid/circuit capacity and could strand small customers
Solar Photovoltaic: Ground Mounted (1 MW)				
		− Expansion could limit residential entry onto circuits − Expansion could limit AG potential	o Already installed — Lanai utility system	
Solar Thermal (Trough 50 MW)				
Not applicable to Lanai utility system	Not applicable to Lanai utility system	Not applicable to Lanai utility system		
Geothermal				
Not applicable to Lanai utility system	Not applicable to Lanai utility system	Not applicable to Lanai utility system		
Ocean Wave: Offshore Generation				
−/o Visual Impact: obstruction of view planes & aesthetics (depends on size and location) − Hazards to whale migration, fish, birds, etc. − Reef Impact: damage from cable laying and directional drilling − EMF impacts on sea-life − Onshore termination: land impacts, land use, visual impacts for onshore conversion stations	− Could negatively impact fishing/gathering practices			o Depends on whether economics would work for Lanai's small grid

Environment	Culture	Community Values	Other	Utility System
Ocean Thermal Energy Conversion				
−/o Visual Impact: obstruction of view planes & aesthetics (depends on size and location) − Hazards to whale migration, fish, birds, etc. − Reef Impact: damage from cable laying and directional drilling − EMF impacts on sea-life − Onshore termination: land impacts, land use, visual impacts for onshore conversion stations	− Could negatively impact fishing/gathering practices			o Depends on whether economics would work for Lanai's small grid
Biomass Combustion				
− Potential use of invasive species	− Potential proximity to culturally sensitive areas	+ Sustainable jobs + Sustainable agriculture		
Waste-to-Energy (Municipal Solid Waste Mass Burn)				
+ Would increase life of land fill		+ Would increase life of land fill		
Fuel Cells: Utility Scale				
Not currently applicable to Lanai utility system	Not currently applicable to Lanai utility system	Not currently applicable to Lanai utility system		
Battery Energy Storage: Utility Scale				
		− Potential fire hazard	o Battery type and safety record are critical concerns	
Internal Combustion Engines: Utility Scale				
Not currently applicable to Lanai utility system	Not currently applicable to Lanai utility system	Not currently applicable to Lanai utility system		
Combustion Turbines				
Not currently applicable to Lanai utility system	Not currently applicable to Lanai utility system	Not currently applicable to Lanai utility system		

Environment	Culture	Community Values	Other	Utility System
Deactivation / Retirement of Existing Generation Units				
+ Land use improvement		− Cost of remediation	− Preferable to keep units available but use less expensive fuel	− Cost of remediation
Fuel Switching: USLD and LSFO				
			− Only done to meet environmental regulations	
Fuel Switching: Locally Produced Biofuels				
		+ Sustainable jobs + Sustainable agriculture	+/o Requires finding right source for economical price	
Fuel Switching: Imported Biofuels				
			+/o Requires finding right source for economical price	
Fuel Switching: Liquefied Natural Gas				
+ Cleaner than diesel		+ LNG makes most economic sense for Lanai's small load and is supported by community	+/− Requires finding right source for economical price	
Undersea Transmission Cable				
− Whale habitat: dangers posed by cable laying ships and submerged cable − Reef Impact: damage from cable laying and directional drilling − EMF impacts on sea-life − Onshore termination: land impacts, land use, visual impacts for onshore conversion stations	− Potential proximity to culturally sensitive areas	− Onshore termination: land impacts, land use, visual impacts for onshore conversion stations −/+ Restrictions on fishing can provide/promote sanctuary	− Community opposition could prevent or delay implementation	

Environment	Culture	Community Values	Other	Utility System
Transmission and Distributions Installations				
– Visual impacts of overhead lines	o Any new lines have to avoid cultural sites	o Past discussions have shown preference for undergrounding any new lines		
Advanced Metering / Smart Grid				
		– Low priority for Lanai (cost)		

Chapter 18: Competitive Bidding and Resource Acquisition

The Competitive Bidding Framework (adopted by the Public Utilities Commission at the end of 2006) established a competitive bidding mechanism for acquiring future generation in the state of Hawaii. The Hawaiian Electric Companies' efforts to acquire new generation have been directed at acquiring renewable energy generation to meet the aggressive RPS targets set in 2009, and have resulted in the addition of substantial amounts of wind, photovoltaic, geothermal and biomass capacity. Their ongoing efforts are focused on acquiring low cost energy and replacement capacity, via competitive bidding and selected waivers, to meet environmental and RPS mandates, while reducing the use of fuel oil and the cost of electricity for customers.

Hawaii Energy Policy

The State of Hawaii has adopted one of the country's most progressive energy policies in an effort to free the State from its dependence on imported oil, to provide the State with the energy security and independence it requires, and to address issues associated with global warming.[65] Hawaii's energy policy, as evidenced by the Hawaii Clean Energy Initiative (HCEI), the Hawaii Renewable Portfolio Standards (RPS) law, and other State laws and initiatives, strongly supports the development and use of Hawaii's indigenous renewable energy resources to produce electricity, to reduce Hawaii's current dependence on imported fuel oil, and to reduce the cost of electricity in Hawaii.

The Hawaii Clean Energy Initiative (the HCEI) was initiated in January 2008, when the State of Hawaii and U.S. Department of Energy (DOE) signed a memorandum of understanding to establish a long-term partnership between the State of Hawaii and DOE that will result in a fundamental and sustained transformation in the way in which renewable and energy efficiency resources are planned and used in the State.[66]

On October 20, 2008, the Governor of the State of Hawaii; the Department of Business Economic Development and Tourism (DBEDT); the Consumer Advocate; and Hawaiian Electric, on behalf of itself and its subsidiaries, Hawaii Electric Light Company and Maui Electric Company (the Hawaiian Electric Companies) (all collectively, the HCEI Parties), signed an Energy Agreement (referred to as the HCEI Agreement).[67]

The HCEI Agreement provides that the signatories will pursue a wide range of actions with the purpose of decreasing the State of Hawaii's dependence on imported fossil fuels through substantial increases in the use of renewable energy and implementation of new programs intended to secure greater energy efficiency and conservation. The agreement includes a number of undertakings intended to accomplish the purposes and goals of the HCEI Agreement, many of which were or are subject to Commission approval.

The HCEI Agreement provides for the HCEI Parties to pursue an overall goal of providing 70% of Hawaii's electricity and ground transportation energy needs from clean energy sources, including renewable energy and energy efficiency, by 2030. To help achieve the HCEI Agreement goals, the agreement further provided for the HCEI Parties to seek an amendment to

[65] Hawaii Revised Statutes (HRS) § 342B-71234 (signed into law in July 2007) requires a statewide reduction of greenhouse gas (GHG) emissions by January 1, 2020 to levels at or below the statewide GHG emission levels in 1990.

[66] Further information regarding the Hawaii Clean Energy Initiative can be found on the HCEI Website: http://www.hawaiicleanenergyinitiative.org/.

[67] A copy of the Energy Agreement can be found on Hawaiian Electric's Website: http://www.heco.com/portal/site/heco/menuitem.508576f78baa14340b4c0610c510b1ca/?vgnextoid=195aca9d24c2d110VgnVCM1000005c011bacRCRD&vgnextfmt=default&cpsextcurrchannel=1.

the RPS to increase the then current requirements and to seek establishment of energy efficiency goals through an energy efficiency portfolio standard. The RPS law and the status of the Hawaiian Electric Companies in achieving the standards are discussed in the section that follows.

The HCEI Agreement further provided that the Hawaiian Electric Companies would continue to negotiate with developers of proposed projects (identified in the Energy Agreement) to integrate approximately 1,100 MW from a variety of renewable energy sources, including solar, biomass, wind, ocean thermal energy conversion and wave. The proposed projects resulted from proposals submitted to the Hawaiian Electric Companies prior to the adoption of the Competitive Bidding Framework (which are referred to as "grandfathered" projects), proposals that were exempt from or received waivers from the Competitive Bidding Framework, and proposals (both conforming and non-conforming) submitted in response to Hawaiian Electric's 2008 RFP for Renewable Energy Projects, Island of Oahu (June 2008 RFP)[68]. The status of these efforts is detailed in the sections that follow.

One of the key concepts underlying the commitments in the HCEI Agreement was the understanding that much of Hawaii's developable renewable energy resources are located on islands other than Oahu, but the primary load that can utilize electricity generated from those resources is on Oahu. For example, Hawaiian Electric had received two proposals for large wind farms on Lanai and Molokai as a result of its June 2008 RFP. Energy from renewable energy generators on islands other than Oahu would have to be delivered to Oahu by undersea cable systems (such as those systems already in service around the world) that either directly connected the generators to the Oahu system, or that connected the systems on Oahu and the other islands. Thus, the HCEI Agreement included commitments for implementation studies to analyze the issues involved in connecting off-Oahu generators and grids. The status of the actions taken to meet these commitments also is detailed in the sections that follow.

The world has changed since the HCEI Agreement was signed over four years ago. The majority of the energy produced to serve Hawaii's electricity needs is still generated from oil-fired dispatchable generation, but the cost of fuel oils burned in the power plants is high, and is expected to increase as cleaner fuel oil is needed to comply with new clean air regulations. The result is high electric rates.

Challenging economic conditions, incentives for energy efficiency programs, high electricity prices, and substantial tax incentives and lower system costs for customer-sited PV systems, have combined to reduce system loads and sales.

The only certainty is uncertainty.

[68] Docket No. 2007-0331.

As a result, the Hawaiian Electric Companies' focus and strategies with respect to acquiring new supply-side resources have to change as well, while accounting for the continued uncertainty as to what the future will bring.

On Oahu, Hawaiian Electric's focus is on continuing to acquire renewable energy resources, while lowering the cost of electricity on Oahu in both the near term and the longer term by (1) acquiring LNG, a cheaper, cleaner fuel to burn while transitioning to a renewable energy future, (2) deactivating, decommissioning, or retiring, older, less efficient generating units at the Honolulu and Waiau Power Plants, and (3) taking advantage of currently available, lower cost intermittent renewable generation through waiver requests and RFPs.

On the island of Hawaii, HELCO has the opportunity to acquire new, dispatchable, renewable generation (1) by utilizing more of the geothermal-sourced energy from the recently expanded PGV facility, (2) by purchasing power from the planned Hu Honua biomass-fired facility, and (3) acquiring new geothermal-sourced power through its on-going geothermal RFP.

On Maui, three wind farms now provide up to 72 MW of wind energy, and the challenge is to continue to change MECO's system so as to be able to accept more of the electricity generated by the wind farms. In addition, PV installations have expanded exponentially, and MECO continues to work with customers to facilitate continued installations, while maintaining system reliability. At the same time, MECO is committed to retiring its Kahului Power Plant, which provides 36 MW of firm capacity and system support for a 23 kV system, and MECO must take the steps necessary to replace this capacity in a cost-effective manner. In parallel, MECO will develop demand response (DR) programs, evaluate assigning capacity value to intermittent renewable generation resources, evaluate energy storage for capacity deferral benefits, and acquire any new generation through a competitive bid process. These parallel efforts are aimed at evaluating and deploying the correct set of reliable and cost-effective solutions to help MECO achieve its clean energy goals. In working to modernize its grid, MECO is leveraging its resources by working with third parties such as the U.S. Department of Energy and Japan's New Energy and Industrial Technology Development Organization and others, to share in costs to transform grid infrastructure.

On Lanai, MECO continues to acquire renewable energy resources through customer-sited PV installations. For the longer term, MECO is focusing on (1) acquiring LNG; (2) pursuing cost effective renewable energy projects that are accepted by the community (potentially biofuel, biomass, and utility-scale PV with a battery) and (3) modernizing its grid through measures such as AMI, Smart Grid, and asset management.

On Molokai, MECO's continues to acquire renewable energy resources through customer-sited PV installations, and its BESS project is intended to provide frequency regulation and PV integration support. For the longer term, MECO is focusing on (1) acquiring LNG; (2) pursuing cost effective renewable energy projects that are accepted by the community (potentially biofuel, biomass, and utility-scale PV with a battery); and (3) modernizing its grid through measures such as AMI, Smart Grid, and asset management.

The following sections of this chapter summarize steps taken to acquire new supply-side resources, the Hawaiian Electric Companies' plans with respect to RFPs, and waiver applications pursuant to the Framework for Competitive Bidding.

Renewable Portfolio Standard (RPS)

Hawaii's RPS law mandates that Hawaiian Electric and its subsidiaries generate or purchase a certain percentage of their net electricity sales over time from qualified renewable resources. Act 155, which was enacted in 2009[69] with the support of the Hawaiian Electric Companies, increased the RPS requirement for electric utilities in 2020 from 20% to 25%, and added a new 40% requirement for the year 2030. The RPS law allows the Hawaiian Electric Companies to aggregate the electricity sales and energy from renewable energy to meet the RPS on a consolidated basis[70].

Since the RPS law requires a certain percentage of electricity sales to be from renewable energy, and the IRP Framework requires each utility to conform to all laws and state energy objectives, the requirements of the RPS law affect the mix of future resources in the utility's integrated resource plans.

The Hawaiian Electric Companies are committed to meeting and exceeding the RPS requirements and have developed strategies, as reflected in their IRP Action Plans, to increase their renewable energy portfolio and to manage the risks associated with this effort. The Hawaiian Electric Companies' strategy is to actively seek and incorporate diverse new renewable energy resources, including wind, solar, hydroelectric, geothermal, biomass, and other types of renewable generation that may emerge in the future. In addition to adding more renewable energy resources, Hawaiian Electric's greening of its existing generating units through the use of sustainable biofuels will also displace fossil fuel use and produce renewable energy.

Having a renewable energy portfolio comprised of a diversified mix of resources is the prudent approach to meeting the Hawaiian Electric Companies' RPS requirements. There is no single renewable energy resource capable of providing a "silver bullet" hedge against oil price volatility. Thus, meeting Hawaii's aggressive RPS goals will require the addition of multiple renewable energy resources into the Hawaiian Electric Companies' systems.

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69 Now codified in HRS § 269-92.

70 HRS § 269-93.

RPS Status

In 2012, the Hawaiian Electric Companies achieved a consolidated RPS penetration level of 28.7%. The RPS law, as amended effective July 1, 2009, will not allow the electrical energy savings from energy efficiency and solar water heating technologies to count towards the RPS from January 1, 2015. Excluding electrical energy savings from energy efficiency and solar water heating technologies, the 2012 renewable generation percentage for the Hawaiian Electric Companies was 13.9% (including 1,093,596 net MWh of electrical energy generated using renewable energy resources and 9,205,998 net MWh of total sales). See Renewable Portfolio Standard Status Report for the year ended December 31, 2012, filed April 24, 2013 in Docket No. 2007-0008.

In 2012, HELCO acquired 507,062 MWh of renewable energy from geothermal, run-of-the-river hydroelectric, wind, and photovoltaic generation compared to total sales of 1,085,171 MWh. The PGV 8 MW expansion was approved by the Commission on December 30, 2011 and placed in service on March 19, 2012. The 21.5 MW Hu Honua biomass facility is expected to be in service in 2014.

In 2012, MECO acquired 238,319 MWh of renewable energy from biomass, wind, photovoltaic, hydroelectric and biofuel generation compared to total sales of 1,114,832 MWh Two 21 MW wind farms were placed in service in 2012.

In 2012, Hawaiian Electric acquired 530,853 MWh of renewable energy from biomass (H-POWER, the City and County of Honolulu's 46 MW waste-to-energy plant), wind, biofuel, and photovoltaic generation — this compared to total sales of 6,975,996 MWh. A new 69 MW wind farm was placed in service on November 2, 2012, the 30 MW Kahuku Wind Farm is expected to return to service in the fall of 2013, and the expansion of the H-POWER facility from 46 MW to 73 MW was completed on April 2, 2013.

Competitive Bidding

In December 2006, the Commission established competitive bidding as the required mechanism to acquire new generation in Hawaii, subject to exemptions specified in the Commission's adopted Framework for Competitive Bidding, and waivers approved by the Commission pursuant to the framework.

With the exception of two renewable generation projects bid into Hawaiian Electric's 2008 Request for Proposals (RFP) for renewable energy projects on Oahu, generation added since 2006 has included exempt utility-owned generation projects that were underway at the time the framework was adopted, exempt non-utility generator projects that were being negotiated at the time the framework was adopted, non-utility generator projects for which waivers were obtained, generation expansion projects that are exempt from competitive bidding, small generation projects that are exempt from competitive bidding, and customer-sited generation acquired through programs established or approved by the Hawaii Legislature or the PUC.

Going forward, however, there are four competitive bidding processes that are underway or planned for Oahu, Maui and Hawaii. In addition, Hawaiian Electric is seeking waivers for certain low cost renewable energy projects on Oahu that were selected as part of an on-going waiver invitation process.

All of the Hawaiian Electric Companies' generation resource acquisition efforts are targeted at acquiring renewable energy generation, with the objectives of meeting and exceeding Hawaii's mandated RPS, dramatically reducing their reliance on fossil fuels, and reducing the cost of electricity for their customers.

The Competitive Bidding Framework, which was adopted by the Public Utilities Commission on December 8, 2006, in Docket No. 03-0372, Decision and Order No. 23121 (Competitive Bidding Framework or Framework), established competitive bidding as the required mechanism for acquiring a future generation resource or block of generation resources in Hawaii, subject to certain conditions and exceptions.

The Competitive Bidding Framework does not apply to certain identified utility generation projects that were already underway at the time the Framework was adopted (and that have since been completed), and to certain identified Non-Utility Generator (NUG) projects that were the subject of on-going negotiations at the time (which are referred to as "grandfathered" projects).

In addition, the Competitive Bidding Framework does not apply to projects that are exempt from competitive bidding as specified in the Framework (which are referred to as "exempt projects"), or to projects for which a waiver from competitive bidding is approved by the Commission (which are referred to as "waivered" projects).

Exemption Provisions in the Competitive Bidding Framework

The Competitive Bidding Framework exempts the following projects from competitive bidding: (i) generating units with a net output available to the utility of 1% or less of a utility's total firm capacity, including that of independent power producers, or with a net output of 5 MW or less, whichever is lower[71]; (ii) distributed generating units at substations and other sites installed by the utility on a temporary basis to help address reserve margin shortfalls; (iii) 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; and (iv) renewable energy or new technology generation projects under 1 MW installed for "proof-of-concept" or demonstration purposes.[72]

For Oahu, the size limit for the exemption is 5 MW, while the limits for HELCO and MECO, based on their 2012 firm capacity amounts, are 2.917 MW and 2.90 MW, respectively.

The Competitive Bidding Framework also does not apply to qualified facilities and non-fossil fuel producers with respect to: (i) power purchase agreements for as-available energy; provided that an electric utility is not required to offer a term for such power purchase agreements that exceeds five years if it has a bidding program that includes as-available energy facilities; (ii) power purchase agreements for facilities with a net output available to the utility of 2 MW or less; (iii) 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; (iv) 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 modification; and (v) renegotiations of power purchase agreements in anticipation of their expiration, approved by the Commission.[73]

Waiver Provisions in the Competitive Bidding Framework

The Competitive Bidding Framework recognizes certain circumstances where competitive bidding may not be appropriate, in which case a waiver may be granted by the Commission. These circumstances include: (i) when competitive bidding will unduly hinder the ability to add needed generation in a timely fashion; (ii) when the utility and its customers will benefit more if the generation resource is owned by the utility rather than by a third-party

[71] For systems that cover more than one island, that is, MECO's system, which has generation on Maui, Molokai and Lanai, the system firm capacity is determined on a consolidated basis.

[72] Framework, Part II.A.3.f.

[73] Framework, Part II.A.3.g.

(for example, when reliability will be jeopardized by the utilization of a third-party resource); (iii) when more cost-effective or better performing generation resources are more likely to be acquired more efficiently through different procurement processes; or (iv) when competitive bidding will impede or create a disincentive for the achievement of IRP goals, renewable energy portfolio standards or other government objectives and policies, or conflict with requirements of other controlling laws, rules, or regulations.[74]

Other circumstances that could qualify for a waiver include: (i) the expansion or repowering of existing utility generating units; (ii) the acquisition of near-term power supplies for short-term needs; (iii) 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; and (iv) the acquisition of power supplies needed to respond to an emergency situation.

Furthermore, the Commission may waive the Competitive Bidding Framework or any part thereof upon a showing that the waiver will likely result in a lower cost supply of electricity to the utility's general body of ratepayers, increase the reliable supply of electricity to the utility's general body of ratepayers, or is otherwise in the public interest.[75]

Relationship of the Competitive Bidding Framework to IRP

The Competitive Bidding Framework is intended to complement the Commission's IRP Framework.[76]

The Competitive Bidding Framework states that for all proposed generation projects included in, or consistent with, IRPs that have not yet been filed with the Commission for approval as of the effective date of the Framework, any waiver request shall accompany the filing of the proposed IRP for the Commission's approval.[77]

A number of waiver requests were submitted and approved while waiting for the IRP Framework to be revised, and the new IRP process to be conducted. The Commission has treated waiver requests as separate docketed matters. The IRP filing identifies potential waiver requests, to the extent they are known at this time, but future waiver request applications will actually be filed when more details regarding the scope of the requested waivers are developed, new opportunities arise, or circumstances change. Thus, waiver requests will continue to be treated as separate docketed matters, unless the Commission directs otherwise.

The Framework requires an electric utility's IRP to specify the proposed scope of the RFP for any specific generation resource or block of generation resources that the IRP states will be subject to competitive bidding.[78] The

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[74] Framework, Part II.A.3.b.
[75] Framework, Part II.A.3.d.
[76] Framework, Part II.C.2.
[77] Framework, Part II.A.4.a.(iii).
[78] Framework, Part II.B.1.

Framework requires RFP processes to be flexible taking into account the appropriate sizes and types of projects identified in the IRP process.[79]

In an IRP proceeding, the Commission will determine whether a competitive bidding process will be used to acquire a generation resource or a block of generation resources that is included in the IRP.[80] Competitive bidding for IRP-designated resources will normally occur after the IRP is approved, through an RFP, which is consistent with the IRP approved by the Commission.[81]

Competitive bidding is integrated into an IRP using the following approach:[82]

1. The electric utility conducts an IRP process, culminating in an IRP that identifies a preferred resource plan. The IRP will identify those resources for which the utility proposes to hold competitive bidding,[83] and those resources for which the utility seeks a waiver from competitive bidding, and shall include an explanation of the facts supporting a waiver, based on the waiver criteria set forth in Competitive Bidding Framework.
2. The Commission approves, modifies, or rejects the IRP, including any requests for waiver, under the IRP Framework and the Competitive Bidding Framework.
3. The electric utility conducts a competitive bidding process, consistent with the IRP. The process will include the advance filing of a draft RFP with the Commission, which shall be consistent with the IRP.
4. The electric utility selects a winner from the bidders.[84]

The Framework provides that competitive bidding shall be structured and implemented in a way that facilitates an electric utility's acquisition of supply-side resources identified in a utility's IRP in a cost-effective and systematic manner, consistent with state energy policy.[85]

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79 Framework, Part II.B.5.

80 Framework, Part II.C.3.

81 Framework, Part II.C.3.

82 Framework, Part II.C.4.

83 The IRP Framework requires IRP analyses to consider and identify, to the extent feasible, those resources which the utility proposes to acquire through its available resource procurement mechanisms, including competitive bidding. See IRP Framework, Part V.C.8.f.

84 An evaluation of bids in a competitive bidding process may reveal desirable projects that were not included in an Approved IRP. The Competitive Bidding Framework provides that such projects may be selected if it can be demonstrated that the project is consistent with an Approved IRP and that such action is expected to benefit the utility and its ratepayers. See Framework, Part II.C.5. Alternatively, an evaluation of bids in a competitive bidding process may reveal that the acquisition of any of the resources in the bid will not assist the utility in fulfilling its obligations to its ratepayers. In such a case, the Framework provides that the utility may determine not to acquire such resources and notify the Commission accordingly. Such notification will include: (a) an explanation of why the competitive bidding process failed to produce a viable project; and (b) a description of what actions the electric utility intends to take to replace the resource sought through the unsuccessful competitive bidding process. See Framework, Part II.C.6.

85 Framework, Part IV.A.1.

Hawaiian Electric Acquisition of Generation Resources

Grandfathered Projects

Kahuku Wind

The Kahuku Wind Power, LLC (Kahuku Wind) project was one of the projects grandfathered from the requirements of the Competitive Bidding Framework adopted in December 2006. On April 30, 2008, the Commission set a deadline of September 2, 2008 for Hawaiian Electric to reach agreement on term sheets with developers of grandfathered projects exempt from competitive bidding. Hawaiian Electric and Kahuku Wind signed a term sheet on September 2, 2008.

On May 12, 2010, the Commission approved the PPA with Kahuku Wind dated July 2, 2009 and filed for approval on August 5, 2009, as amended by a First Amendment dated January 22, 2010, and filed February 1, 2010.

The Kahuku Wind farm achieved commercial operations on March 23, 2011.

Pricing in the Kahuku Wind PPA is a composite of a base energy price and an adder for the amortized cost of a Battery Energy Storage System (BESS), which was built by Xtreme Power. The experimental pairing of the wind turbines with the BESS was meant to meet Hawaiian Electric performance standards for voltage regulation and ramp rate.

Fires occurred within the BESS enclosure on April 22, 2011, May 23, 2011, and again on August 1, 2012, the last of which destroyed the entire building housing the BESS and its contents. The Kahuku Wind farm has been offline since the August 1, 2012 fire. Hawaiian Electric and Kahuku Wind have been working collaboratively to rebuild interconnection facilities and bring the wind farm back to commercial operations.

Hawaiian Electric and Kahuku Wind are conducting an updated Interconnection Reliability Study (IRS) and negotiating a PPA amendment, both centered around Kahuku Wind's proposal to replace the BESS with a Dynamic Volt-Amp Reactive (DVAR) system. If the DVAR can sufficiently improve the facility's basic performance, then the total price will be decreased to reflect the substitution of a DVAR adder for the original BESS adder. Hawaiian Electric and Kahuku Wind anticipate that the Kahuku Wind farm will go back into commercial operations in 2013.

Honua Power

On January 19, 2011, the Commission approved Hawaiian Electric's power purchase contract with Honua Power, LLC (Honua Power) dated December 1, 2009, to purchase approximately 6.6 MW of as-available energy from a biomass gasification facility. A first amendment dated June 24, 2010, involving only technical revisions, was filed with the Commission on June 24, 2010. On February 27, 2013, in Decision and Order No. 31044, the Commission approved the second amendment to the power purchase contract dated January 24, 2013, subject to the condition that Honua Power provide evidence of financial closing by April 1, 2013, which subsequently was extended until June 1, 2013. Honua Power's letter dated and filed May 31, 2013 indicated that Honua Power did not reach initial financial closing, but that it will work with potential investors to develop a detailed financing plan and timeline. Honua Power's letter also requested that the Commission delay any action with regard to reconsidering its decision (regarding the second amendment) until the end of June 2013.

Ocean Thermal Energy Conversion (OTEC)

Sea Solar Power, International, LLC, now known as OTEC International LLC (OTI) proposed a 100 MW (average net to the utility) ocean thermal energy conversion (OTEC) facility to provide as-available energy to Hawaiian Electric in 2006. The proposed OTEC project was one of the projects grandfathered from the requirements of the Competitive Bidding Framework adopted in December 2006. On April 30, 2008, the Commission set a deadline of September 2, 2008 for Hawaiian Electric to reach agreement on term sheets with developers of projects exempt from competitive bidding. Hawaiian Electric and OTI signed a term sheet on September 2, 2008. Since then, OTI has designed its facility with sufficient details to allow completion of preliminary engineering studies. Hawaiian Electric and OTI are in active negotiations to conclude a PPA in 2013.

OTI's facility is planned to be located off the coast of Oahu directly in front of Hawaiian Electric's Kahe Power Plant. As there are no OTEC facilities in commercial operation, the term sheet provided for a two phased approach. During Phase 1, OTI will demonstrate the ability of the facility to meet performance criteria for reliability and power quality. Energy provided during this phase will be as-available energy. If OTI successfully passes the requirements for Phase 1, it will be allowed to provide scheduled energy under Phase 2 for the remainder of the term of the contract. Assuming that contract negotiations are completed on schedule, OTI's facility can be in service in 2019.

The OTEC technology uses heat from warm surface ocean water to evaporate a working fluid, which turns turbine-generators to produce electricity. Cold deep ocean water is then used to condense the vaporized working fluid to liquid, which can be used again in the process. Pumps are employed to obtain the warm surface and cold deep ocean water for evaporation and condensation.

The heat in the surface ocean water is a function of the water temperature. The surface water temperature changes seasonally, and to a much smaller degree on a daily basis. The temperature of the deep ocean water does not change seasonally. Thus the fuel source (heat) is predictable and steady, resulting in the electric output from the facility also being predictable and steady. Consequently, OTEC facilities can produce energy on a scheduled basis, similar to conventional fossil fuel power plants, unlike the intermittent nature of energy from other renewable energy sources. OTEC facilities can produce the greatest amount of energy during the summer months when Hawaiian Electric's system load is high, and will produce relatively smaller amounts of energy during the winter months when Hawaiian Electric's system load is low.

The term sheet provides for a maximum facility output of 119 MW net to Hawaiian Electric, and an engineering study has confirmed that Hawaiian Electric's system can accept the maximum output without any system modifications. According to OTI, the net output varies between an average of 90 MW during the "winter" months of December through May, and 110 MW during the "summer" months of June through November. Hawaiian Electric has agreed to accept up to 119 MW between the hours of 5:00 a.m. to midnight, but because of system load characteristics, can only currently accept 25 MW between the hours of midnight to 5:00 a.m.

In order to be able to deliver 90 MW during the winter months, OTI has engineered their facility such that it can provide more than 119 MW. Hawaiian Electric may agree to accept more than 119 MW between the hours of 5:00 a.m. and midnight, and more than 25 MW between the hours of midnight and 5:00 a.m. only after additional engineering studies confirm these operating scenarios.

OTEC facilities can serve to further diversify renewable energy resources beyond geothermal, biomass, wind, and solar. Finally, OTEC facilities are situated in the ocean, except for land-based interconnection equipment, thus greatly reducing the land necessary for the facility.

As there are no OTEC facilities in commercial operation, OTEC is considered a new technology. Thus, it is not formally part of the IRP Action Plan. Hawaiian Electric recognizes the potential attributes of an OTEC plant as stated above, and is pursuing a power purchase contract which will prove the technology and provide sufficient safeguards for Hawaiian Electric's system if the developer does not meet its contractual obligations.

Exempt Projects

H-POWER Expansion

On May 25, 2012 in Docket No. 2012-0129, Hawaiian Electric submitted an application for approval of an Amended and Restated PPA with the City & County of Honolulu to purchase up to an additional 27 MW of power from an expansion of the existing 46 MW waste-to-energy facility known as H-POWER. On November 15, 2012, Hawaiian Electric filed Amendment No.1 to the PPA. On January 17, 2013, in Decision and Order No. 30950, the Commission approved the PPA as amended. The expansion was placed in service on April 2, 2013.

Kalaeloa Partners, L.P.

Hawaiian Electric's existing PPA with Kalaeloa Partners, L.P. (KPLP) (as amended), pursuant to which it purchases firm capacity and energy from a 208 MW dual-train combined cycle facility fired on LSFO, expires on May 23, 2016. On November 10, 2011, Hawaiian Electric submitted to the Commission a Petition for Declaratory Order regarding the Exemption of Kalaeloa Partners, LP's project from the Framework for Competitive Bidding, or in the alternative, Approval of Application for Waiver from the Framework for Competitive Bidding.

In the petition, Hawaiian Electric stated that KPLP "committed in the [PPA renegotiations] for an Amended and Restated PPA to have the operational capability to burn up to 100% biofuels in its two (2) existing combustion turbines if such fuels meet KPLP's plant equipment specifications and are available at a cost deemed reasonable to Hawaiian Electric's customers." Hawaiian Electric also explained that to operate on up to 100% renewable biofuels, KPLP would be required to "upgrade" its facilities. Notwithstanding such capital investments, Hawaiian Electric nonetheless anticipates that the renegotiations for the Amended & Restated PPA will yield a cost structure for fixed costs that would be at or below the existing fixed cost structure set forth in the existing PPA.

On May 14, 2012, in Decision and Order No. 30380, the Commission declared that the proposed renegotiation of the Amended and Restated PPA is exempt from the competitive bidding process. The Commission clarified that Hawaiian Electric and KPLP should not limit their renegotiations for an Amended and Restated PPA to use of renewable biofuels to meet RPS requirements, but should also explore use of other carbon-reducing fuels, whether renewable or fossil based, that will provide ratepayers with cleaner, more cost-effective, or more efficient alternatives to KPLP's existing fuel resources. The Commission further ordered Hawaiian Electric to file as a non-docketed filing, an annual report which describes: (A) the status of its negotiations with KPLP; (B) the status of KPLP's ability to utilize and obtain other fuel sources, whether renewable or fossil fuel resources; and (C) any actions taken by Hawaiian Electric to conduct parallel planning as authorized under the Competitive Bidding Framework, including, but not necessarily limited to, actions to obtain additional generation resources, such as through the pending competitive bidding process in Docket No. 2011-0039.

On January 31, 2013, Hawaiian Electric filed its annual report describing the status of its negotiations with KPLP.

Hawaiian Electric is currently in discussions with KPLP to renegotiate the existing PPA so that the KPLP facility can continue to provide reliable firm capacity and heat rate efficient energy production through its existing facility.

AES

Hawaiian Electric's existing PPA with AES (as amended), pursuant to which it purchases firm capacity and energy from a 180 MW coal-fired facility, has a term that extends through September 1, 2022. In a letter to Hawaiian Electric dated April 20, 2012, AES indicated that "[it] has been operating with fixed energy pricing while having to buy coal in a highly volatile international market. The inability to procure coal under long term fixed price contracts as when the project was originally developed over 20 years ago has had negative impacts on the business."

On August 13, 2012, Hawaiian Electric filed a petition seeking a declaratory order regarding exemption from the Framework, or alternatively, an approval of application for waiver from the Framework regarding the Power Purchase Agreement with AES.[86]

On April 25, 2013, the Commission issued a decision granting Hawaiian Electric's request for an exemption from competitive bidding based on the facts presented and representations made by Hawaiian Electric in its petition. The Commission's decision and order states as follows:

- Hawaiian Electric and AES will begin renegotiations this year toward an amended and restated PPA
- Subject to Commission approval, Hawaiian Electric and AES will consider having any amended and restated PPA be effective prior to termination of the existing term (September 1, 2022), and the new term would extend past September 1, 2022
- Hawaiian Electric and AES will execute the amended PPA, if any, no later than six months after the filing of this Order, unless a longer period of time for executing the amended PPA is mutually agreed by Hawaiian Electric and AES, or the negotiation will be concluded without an amendment to the PPA. (The amended and restated PPA will be subject to Commission approval.)
- AES shall provide full access to Hawaiian Electric, the Commission, and the Consumer Advocate, to all current and projected financial information and all operational and maintenance documents related to the AES Facility, including, but not limited to financial statements to date, pro forma financial information projections, fuel supply agreements, fuel cost information, fuel procurement procedures, O&M costs, recommendations from experts on maintenance practices, and information on the condition of the AES Facility, subject to protective order where appropriate.
- AES will work with Hawaiian Electric to explore the use of other carbon reducing fuels, whether renewable or fossil based, that will provide ratepayers with cleaner, more cost-effective or more efficient alternatives to the existing fuel resources used by AES.

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[86] Docket No. 2012-0197.

- AES will give full cooperation and consideration to the need to show, on the whole, through the financial information described above and otherwise, (1) that an amended and restated PPA, including an extended term, is beneficial to Hawaiian Electric's customers in comparison to continuing its obligations under the existing PPA, (2) that its expected rate of return appropriately reflects the reduction in fuel pricing risks that is being sought by AES in an amended and restated PPA, and (3) what AES's actual costs are and will be, all with a view to demonstrating why the pricing in an amended and restated PPA is fair and in the interest of Hawaiian Electric's customers.

The Commission also required Hawaiian Electric to provide the Commission and Consumer Advocate with an annual report on the status of negotiations with AES, the status of AES's ability to utilize and obtain renewable fuel resources, and any actions Hawaiian Electric is taking to conduct parallel planning as allowed under the Competitive Bidding Framework, such as actions to obtain additional sources of generation through the competitive bidding process in Docket No. 2011-0039. The first annual report covering the 2013 calendar year is due on January 31, 2014.

Other Exempt Renewable Projects on Oahu (5 MW or Less)

Oahu generation projects that are sized at less than or equal to 5 MW are exempt from competitive bidding, and a number of such projects have been added or are under consideration.

A PPA for Kapolei Sustainable Energy Park, a 1 MW PV project located in Campbell Industrial Park, was filed and approved by the Commission in Docket No. 2011-0185 on November 18, 2011. The project went into commercial operation on December 30, 2011.

A PPA for Kalaeloa Renewable Energy Park, a 5 MW PV project located in Campbell Industrial Park, was filed and approved by the Commission in Docket No. 2011-0384 on October 22, 2012. The project is under construction and is expected to achieve commercial operations in 2013.

Another PPA for IC Sunshine LLC, a 5 MW PV project located in Campbell Industrial Park, was filed and approved by the Commission in Docket No. 2011-0015 on January 26, 2012. After the PPA was approved, the developer lost its land lease for the project. Hawaiian Electric and the developer mutually agreed to terminate the PPA on April 8, 2013.

In addition, Hawaiian Electric is engaged in ongoing PPA discussions with developers for eight 5 MW PV projects located in west and central Oahu.

Oahu Waivered Projects

Schofield Generating Station

On August 1, 2012, in Decision and Order No. 30552, the Commission granted, subject to conditions, Hawaiian Electric's request for a waiver from the Framework for Competitive Bidding for the proposed Schofield Generating Station (SGS) project.[87] The Commission identified a number of questions and concerns that will need to be addressed in an application requesting approval to commit funds for the project.

The SGS project will add approximately 50 MW of load following/peaking/cycling generation consisting of six 8.4 MW biofueled reciprocating engine-generator sets and associated equipment. The project also will provide fast start (8-minute) dispatchable capacity. The engines will be capable of being individually started and dispatched to provide incremental capacity as needed. The project consists of construction of new generation as well as electrical transmission interties.

The project will be located on 10.3 acres within property owned by the United States Army in Wahiawa, Oahu. This property is an undeveloped site with no established infrastructure. The SGS project will include a 2-mile aboveground 46kV transmission line connected to the existing Hawaiian Electric grid.

The project will provide grid-tied, firm, dispatchable, renewable generation to be installed on federal lands for the purpose of ensuring that the Army's critical national security and first responder missions can be carried on, particularly during events when the utility grid on Oahu has been compromised, whether through a natural or man-made disaster. The federal lands would be leased at nominal cost from the Army in exchange for the commitment by the utility to construct the facility and required infrastructure, and to operate, maintain, and support the facility.

The electrical output from the SGS generators will normally supply power to all Oahu customers through the Oahu electrical grid. However, during outages that meet the criteria specified in an operating agreement with the Army, SGS output will be "islanded" to serve only the Army facilities at Schofield Barracks, Wheeler Army Air Field, and Field Station Kunia.

The SGS project will use biofuel and include black start capability in the event of a grid outage, allowing the facility to start-up independently, as well as provide black start capability to support the Oahu grid when necessary.

Mililani Solar Energy Park

Castle & Cooke, Inc. (C&C) approached Hawaiian Electric with the concept of a solar energy park consisting of four 5 MW facilities developed on four adjacent sites. C&C proposed that each facility be independently owned and

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[87] Hawaiian Electric submitted its application for waiver on December 27, 2011, in Docket No. 2011-0386.

developed by a separate PV developer on approximately 30 acres of land leased by C&C to a developer for a term of not less than 20 years, with C&C or its affiliate to be included as one of the four PV developers. The intended impact of these projects was to leverage potential economies-of-scale that could result in lower-cost renewable energy to benefit of Hawaiian Electric's customers. To that end, the solar park project would ostensibly provide an aggregate 20 MW of solar energy, while achieving cost efficiencies from certain shared expense facilities and economies of scale, as well as other optimal characteristics of C&C's site such as an advantageous solar resource.

The Hawaiian Electric sought a declaratory ruling from the Commission, stating that the proposed Mililani solar energy park project was exempt from the Competitive Bidding Framework due to the fact that the proposed projects were separate and distinct 5 MW projects, which aggregated to 20 MW only to the extent that interconnection costs were shared, and that such an approach would result in lower priced energy savings for Hawaiian Electric's customers.

On December 23, 2010, the Commission issued its Decision and Order finding that the Mililani solar energy park project is not exempt from the Commission's Framework. The Commission, however, sua sponte, granted a waiver for the project subject to the terms and conditions set forth below:

A. Fully executed term sheets for each of the projects are filed within four months from the date of the Decision and Order, unless otherwise ordered by the Commission;

B. Documentation supporting the fairness of the price negotiated between Hawaiian Electric and the independent power producers are included in any application for approval of a PPA;

C. Each solar park participant engages and enters into separate contract negotiations with Hawaiian Electric;

D. There be no assumed priority, by way of being a participant in the solar park, over any other proposed project;

E. There be no assumed priority or preference in dispatch or curtailment for any or all of the participants in the solar park as compared to any other intermittent source of renewable energy; and

F. Any common costs be allocated appropriately to the solar park participants.

Hawaiian Electric executed term sheets with four developers on April 21, 2011. The original term sheets had energy pricing set, with an adder to account for high interconnection costs. Upon execution of the term sheets, the parties commenced the interconnection requirements study for the projects. Upon conclusion of the initial interconnection requirements study, the interconnection cost estimates came back higher than expected and Hawaiian Electric asked the developers to reexamine their base pricing because the adders pushed total pricing near FIT Tier 3 levels, thus negating the cost-savings basis for the Commission's waiver. The developers requested that Hawaiian Electric conduct a restudy on the interconnection requirements under different interconnection assumptions. On December 28, 2011, and October 12, 2012, the term sheets were extended to allow for more time for the interconnection requirements study to be completed, and certain provisions of the term sheets, such as pricing, were amended. The interconnection requirements study was completed on February 27, 2013. However, the report recommended that additional technical study work be conducted related to issues with the PSCAD inverter model. The PSCAD inverter work has now been completed and the parties are working to complete the power purchase agreement negotiations before the term sheets expire on August 1, 2013.

Invitation for Waivered Projects

On February 22, 2013, Hawaiian Electric issued an Invitation for Waivered Projects (Invitation) stating that it would consider requesting a waiver from the Competitive Bidding Framework for qualifying low cost renewable energy projects. The Invitation was part of Hawaiian Electric's efforts to lower customers' electric bills in the near-term by seeking qualified utility-scale renewable energy projects on Oahu that developers can quickly place into service at a low cost per kilowatt-hour.

It is possible that the complexity and significant timeline necessary to develop projects through an RFP process is deterring some renewable energy projects capable of much shorter development periods. In addition, some project developers and prospective bidders may have already expended substantial time and resources in preparing their proposals in anticipation of bidding in to one of Hawaiian Electric's proposed RFPs. As a result, it was hoped that by proceeding immediately, some projects would be able to realize significant savings and offer lower energy rates. For example, costs related to retaining land rights for a project site prior to commercial operations may increase the overall cost of energy when the project comes into service.

To take advantage of potential savings on behalf of its customers, Hawaiian Electric stated that it would consider requesting a waiver to proceed with one or more projects that met the following criteria:

1. Proposed projects must be on Oahu and have a nameplate capacity greater than five megawatts from a new renewable source that qualifies under the Hawaii RPS.
2. The energy payment per kilowatt-hour must provide an attractive reduction in cost for Hawaiian Electric customers. Energy rates must be calculated with and without the use of Hawaii State tax incentives.
3. The energy payment rate proposed shall assume a 20-year power purchase agreement (PPA) term. If a significant cost savings can be achieved by a PPA term of 25 years, a reduced energy payment rate reflecting the discount may also be included. If an energy payment rate for a 25-year PPA is included in a proposal, the pricing assumptions and project pro-forma should clearly identify any costs associated with extending the useful life of the project from 20 to 25 years.

4. Developers must have experience in the development and execution of at least one electricity generation project similar in size to the project being proposed. Hawaiian Electric will consider a developer to have reasonably met this criterion if the developer can provide sufficient information to demonstrate that members of the project team being identified to meet this criterion has a firm commitment to provide services to the proposed project.

5. Developers must be willing to provide Hawaiian Electric, the PUC and Consumer Advocate with complete access to all project financial information, including the project pro forma, prior to application for waiver.

6. Developers must provide proof of site control for the 20- to 25-year duration of a PPA, plus preliminary archeological and environmental assessments and an associated permitting plan.

7. Developers must submit evidence of plans for, or actual, community relations outreach in connection with the proposed project.

8. Developers must provide proof of control of fuel source for initial five years of a PPA, if applicable.

9. Proposed projects must demonstrate that they can reasonably attain a commercial operation date no later than the end of 2015. Hawaiian Electric will assess when and to what extent the proposed projects can reasonably be expected to attain commercial operation before the end of 2015, taking into account factors such as the Guaranteed Commercial Operations Date to which the project developer commits, project feasibility, and the likelihood of timely project completion.

10. Developers must accept all terms and conditions contained in the February 2013 Model Power Purchase Agreement for As-Available Energy included as Attachment 4 to this announcement without substantial modification. (For clarity, the terms contained in the Tiered Energy Pricing Alternative Term Sheet, included in the RFP as Appendix S, shall not be included in the PPA of projects selected for a waiver.)

11. Developers must factor into their proposed pricing their own assumptions of interconnection costs and must assume any risk for higher actual costs. To assist developers in pricing their interconnection costs, per unit cost figures are provided in Attachment 2 of this announcement to be used to provide an approximate estimated cost for interconnecting, including substation, communications, and transmission or distribution line cost to the existing Hawaiian Electric system.

12. Proposed projects must comply with performance requirements included in Attachment 1 to this announcement, with the possible exception of (1) Power Up and Down Ramp Rate Control and (2) Inertia Constant. If developer's proposed project is unable to meet the ramp rate control and/or the inertia constant performance requirements, the

developer should specify the most conforming performance characteristics with respect to ramp rate control and/or inertia constant their project is capable of providing.

13. Developers must be committed to meeting the scheduled milestones listed in Table 1 of this announcement.

Project developers submitting proposals for possible waiver projects were also required to agree to participate in "open book" negotiations with Hawaiian Electric, consistent with past PUC waiver approvals. Projects with neutral bill impacts, or that would increase customer bills, were not considered for a waiver request. As such, only projects with a levelized cost of energy below 17 cents/kilowatt-hour, without the use of Hawaii State tax incentives, were considered. Hawaiian Electric expected that any cost savings realized from Hawaii State tax incentives would further decrease the energy payment rate of any selected projects, and as a result, established mechanisms in the PPA to take advantage of this approach.

Hawaiian Electric received twenty-five proposals by the Invitation deadline of 4:00 p.m. on March 22, 2013.[88] Of these twenty-five proposals, fifteen were eliminated due to failure to meet one or more of the initial threshold criteria, including:

- Pricing at or above 17 cents/kWh.
- Inadequate proof of acceptable site control.
- Projects proposed on an island other than Oahu.

Between April 3, 2013, and April 15, 2013, Hawaiian Electric sought to confirm the tax pricing assumptions of the remaining ten developers. Hawaiian Electric offered these developers the opportunity to lower their pricing, indicating that Hawaiian Electric's final selection of projects would be made on the basis of the best and final offers provided in response to this request, assuming the use of the proposed Hawaii state tax credit originally set forth as Senate Bill 623 House Draft 3 of the 2012–2013 session of the Hawaii State Legislature (SB623). Based on the developers' responses to this inquiry, Hawaiian Electric eliminated four of the ten projects on the basis of price. The remaining six developers were notified that their projects were still under consideration, and were requested to provide confirmation of their pricing and agreement with the terms of the model PPA.

Subsequent to this notification, however, Hawaiian Electric became aware that the tax credit bill, SB 623, had failed to pass. As a result, Hawaiian Electric refocused its analysis of the projects on pricing, without the use of Hawaii state tax credits. Accordingly, the ten developers who met the initial threshold requirements were offered an opportunity to refresh their pricing proposals, without the use of Hawaii state tax credits. Hawaiian Electric's evaluation of the refreshed pricing for the ten proposals revealed a natural grouping of projects around the price-point of 16.25 cents per kWh and

[88] One proposal was rejected for failure to meet the 4:00 p.m. deadline.

below. Therefore, Hawaiian Electric selected the five projects with the lowest price per kWh, without the use of Hawaii state tax credits.

On June 18, 2013, Hawaiian Electric filed an Application in Docket No. 2013-0156 requesting waivers from the Framework for Competitive Bidding for the five selected projects (Application for Waivers). The Application for Waivers is currently pending before the Commission.

In addition, on June 17, 2013, Hawaiian Electric issued a pricing refresh opportunity to developers who submitted proposals in response to the Invitation but who were not selected for inclusion in the Application for Waivers. To be considered for further evaluation, the pricing refresh requires that refreshed proposals be below 16.25 cents per kilowatt-hour, levelized over a 20-year contract term, without the use of Hawaii state tax incentives. Pricing refresh proposals are due on July 1, 2013. If Hawaiian Electric receives refreshed proposals that meet the threshold criteria stated in the Invitation and the refreshed pricing criteria, Hawaiian Electric will further evaluate such proposals and may submit a supplemental waiver application for one or more additional projects.

Future Oahu Waiver Requests

Utility-Scale PV Systems

Hawaiian electric intends to request waivers for one or more self-build, fast track, low-cost non-firm PV installations under circumstances in which the Company is situated to offer its customers with a low cost alternative.

The first such project is a proposed Kahe Utility-Scale PV System (KPV), which will add up to 12 MW (AC) of renewable generation consisting of up to 15 MW (DC) of fixed-tilt ground-mounted PV panels. The project is anticipated to be located on the northern side of Hawaiian Electric's Kahe Generating Facility. This portion of the property is an undeveloped site with no established infrastructure. The electrical output from the KPV system will be interconnected to the existing 46kV bus at the Kahe switchyard to serve customers in west Oahu.

The Competitive Bidding Framework states that a waiver may be appropriate when more cost-effective or better performing generation resources are more likely to be acquired more efficiently through different procurement processes; (Section II.A.3.b.(iii)); and where the waiver will likely result in a lower cost supply of electricity to the utility's general body of ratepayers, increase the reliable supply of electricity to the utility's general body of ratepayers, or is otherwise in the public interest (Section II.A.3.d).

The Kahe Utility-Scale PV project satisfies the waiver requirements set forth above in that it is expected to reflect energy pricing that is significantly lower than any previously negotiated renewable energy price with Hawaiian Electric, and would cause an immediate reduction to the cost of energy to Hawaiian Electric's customers. In addition, the expected levelized price of this project without the use of Hawaii state tax incentives is significantly lower than levelized prices, with tax credits, for all other recent renewable energy projects on Oahu approved by the Commission. The KPV project is also an opportunity for the Company to set lower price thresholds in the renewable energy market, and establish a price ceiling for future renewable generation projects.

By proceeding with this low-cost project now, on an expedited basis, this project will be able to offer lower energy rates to Hawaiian Electric customers much quicker and more efficiently. The cost savings will not only start sooner, but may be higher overall if available tax credits are reduced or eliminated in the future.

Campbell Industrial Park Steam Turbine #1

The Campbell Industrial Park Steam Turbine #1 (CIP ST-1) project will add approximately 55 megawatts (MW) of firm capacity to the Oahu system. The project involves adding a Heat Recovery Steam Generator to the discharge of the existing 113 MW CIP CT-1 combustion turbine and using the produced steam to operate a new 55 MW steam turbine. This project will not only add 55MW of capacity to the system, but will effectively result in 168MW of "new" high-efficiency baseload/cycling capability. Conversely, there will be a reduction of 113MW of peaking capability.

The Competitive Bidding Framework states that a circumstance that could qualify for a waiver includes the expansion or repowering of existing utility generating units (Section II.A.3.c.(i)). Conversion of CT-1 to combined cycle operation by adding a Heat Recovery Steam Generator fits this circumstance.

The analyses in *Chapter 10: CIP CT-1 Generating Station Analysis* show that overall, over both the 20-year planning period and the 30-year study period, converting CIP CT-1 to combined cycle operation burning ULSD results in the lowest cost when compared to operating CIP CT-1 in simple cycle mode. Therefore, the quickest way for customers to realize the cost savings from converting CT-1 to combined cycle is to get a waiver from competitive bidding.

The CIP CT-1 combined cycle plant will have an air permit that allows it to use gas, ULSD, and biodiesel, thus allowing it to use the most cost-effective fuel available. It is anticipated that ultimately the combined cycle will use gas (via imported LNG) once it is available since it will likely be the least cost fuel. Prior to the availability of gas, it is expected that ULSD fuel will be the lowest cost fuel available.

Hawaiian Electric Requests for Proposals

June 2008 Renewable Energy RFP

As part of its efforts to accelerate the development of renewable energy projects in its service territory, Hawaiian Electric issued an RFP for Non-Firm Renewable Energy Projects, Island of Oahu, in June 2008 (the June 2008 RFP). Two conforming projects were selected, and are now in commercial operations on Oahu.

- The Kawailoa Wind, LLC (Kawailoa Wind) project is a 69 MW wind farm located on the North Shore of Oahu. The PPA dated September 21, 2011 was approved by the Commission in Docket No. 2011-0224 on December 12, 2011. The project was placed in service on November 2, 2012.
- Kalaeloa Solar 2 is a 5 MW PV project in Kalaeloa on Department of Hawaiian Home Lands (DHHL) property. The PPA dated February 18, 2011 was approved by the Commission in Docket No. 2011-0051 on September 22, 2011. The project commenced commercial operations on December 31, 2012.

West Wind

West Wind submitted a proposal in response to the June 2008 RFP for its 25 MW Na Pua Makani wind project located in Kahuku, Oahu. West Wind was not originally selected to the final award group, and took issue with its non-selection. In 2010, Hawaiian Electric and West Wind attempted to resolve the dispute through mediation, but were unable to reach an agreement. On April 5, 2012, West Wind filed its first Petition for Declaratory Order Or, In the Alternative, For Grant Of Waiver with the Public Utilities Commission in Docket No. 2012-0076 (First Petition), requesting a declaratory order that requires Hawaiian Electric to further consider West Wind's project as part of the 2008 RFP, or, in the alternative, for the Public Utilities Commission to grant a waiver that would permit Hawaiian Electric to negotiate and enter into an agreement with West Wind outside of the Framework for Competitive Bidding. On April 23, 2012, the Public Utilities Commission dismissed the First Petition without prejudice after finding that Hawaiian Electric was an "affected public utility" that may have an interest in the matter, but was not served with a copy of the First Petition. On April 27, 2012, West Wind filed its second Petition for Declaratory Order Or, In the Alternative, For Grant Of Waiver with the Public Utilities Commission in Docket No. 2012-0094 (Second Petition). On May 17, 2012, Hawaiian Electric filed a Motion to Intervene. On August 24, 2012, West Wind and Hawaiian Electric submitted a joint letter to the Commission requesting to suspend the procedural schedule for the proceeding to give the parties an opportunity to resume discussions regarding the Na Pua Makani wind project. In particular, the parties agreed to proceed with an Interconnection Requirements Study (IRS) to determine the requirements, including estimated costs, of interconnecting the Na Pua Makani project to the Hawaiian Electric system on a different circuit that may have sufficient capacity for the project. The parties further notified the Commission that, depending on the results of the IRS and any terms offered by West Wind, the parties may enter into negotiations for a power purchase agreement.

Lanai Wind Project

In 2011, Hawaiian Electric signed a term sheet with Castle & Cooke Resorts, LLC (C&CR) to provide renewable energy generation resources from a proposed 200 MW wind farm on Lanai to the Hawaiian Electric system (Lanai Wind Farm).

Hawaiian Electric received two non-conforming proposals, in response to the June 2008 RFP, for large wind farms (in the 350–400 MW range) on the islands of Lanai and Molokai, with the power to be transmitted via undersea cable to Oahu. These proposals for the proposed Lanai Wind Farm and a proposed Molokai wind farm are sometimes referred to as the "Big Wind Projects", or "Inter-island Wind Projects". As contemplated by the HCEI Agreement, Hawaiian Electric and the two developers of the proposed Big Wind Projects entered into a "Bifurcation Agreement" at the end of 2008, in which each developer agreed to develop an up to 200 MW wind farm on Lanai or Molokai, subject to Commission acceptance of the arrangement. Under the Bifurcation Agreement, if one of the developers failed, the other would get most of the total project.

The Commission ultimately granted a waiver from the Competitive Bidding Framework for the bifurcated proposals, finding that, in light of the public interest and in order to achieve a stated governmental objective, Hawaiian Electric was entitled to a waiver from the Competitive Bidding Framework, provided that (1) fully executed term sheets for each of the proposed Lanai Wind Farm and the proposed Molokai wind farm, were filed within four months from the date of the Decision and Order (by March 2011), unless otherwise ordered by the Commission, and (2) documentation supporting the fairness of the price negotiated between Hawaiian Electric and C&CR or the developer of the proposed Molokai wind farm, as applicable, was included in any application for approval of a PPA.

The term sheet between Hawaiian Electric and C&CR, the proposed Lanai Wind Farm developer, was filed on March 21, 2011 (Lanai Term Sheet). Hawaiian Electric was unable to complete a term sheet with the proposed developer of the proposed Molokai wind farm. The term sheet with C&CR provided that, because Hawaiian Electric was unable to timely execute a term sheet with the developer of the proposed Molokai wind farm, C&CR had the option to either develop an up to 400 MW wind farm on Lanai or to develop a 200 MW wind farm on Lanai and arrange for the development of an up to 200 MW wind farm on Molokai (with confirmation of control of the Molokai site) such that the capacities of the Proposed Lanai Wind Farm and any proposed Molokai wind farm total 400 MW. C&CR elected the second option.

In a July 14, 2011, Order issued in Docket No. 2009-0327, the Commission confirmed the waiver granted to Hawaiian Electric and C&CR to develop the 200 MW proposed Lanai Wind Farm, subject to the Commission's approval of a PPA, and other necessary permits and approvals. However, instead of accepting the option for another 200 MW in the term sheet with the proposed Lanai Wind Farm developer, the Commission directed Hawaiian Electric to submit a new RFP for a minimum of 200 MW of renewable energy for delivery to the Hawaiian Electric system on the island of Oahu according to the Competitive Bidding Framework. (The proposed Lanai Wind Farm and proposed Molokai wind farm were expected to produce an aggregate of approximately 1500 GWh of renewable electrical energy on an average annual basis. Hawaiian Electric is therefore seeking approximately 600-800 GWh of renewable electrical energy on an average annual basis in the Renewable Energy and Undersea Cable System Projects Delivered to the Island of Oahu RFP to replace the 200 MW of renewable energy that would have been generated by the proposed Molokai wind farm.)

The Lanai Term Sheet is confidential, but the pricing is not. The term sheet basically incorporates the pricing in the Letter Agreement between Castle & Cooke Resorts, LLC and Hawaiian Electric dated January 3, 2011 (Lanai letter agreement), which is included as Appendix 8 to the Navigant Report (Status and Perspective on the Big Wind/Cable Project, dated April 19, 2011, prepared for DBEDT by Navigant Consulting, Inc.).

Attachment A to the Letter Agreement provides that the total price of wind energy produced on Lanai and delivered to Oahu electric customers must be reasonable and clearly cost competitive with other renewable energy options in order for the Inter-island Wind project to be feasible. In furtherance of this, and in anticipation of costs of transmission that will be incurred on Oahu and for the undersea cable between Oahu and Lanai, the parties agreed that pricing for wind energy delivered to a point of interconnection at a converter station on the island of Lanai should be at or about $130/MWh on a levelized basis over the term of the PPA for a 200 MW wind farm (and $110/MWh for a 400 MW wind farm). The price does not have to be flat for the term, but can start a lower price and escalate to higher price. For example, an energy price of $120.71/MWh in the first year escalating to $145.83/MWh in the 20th year, which incorporates a 1% per year escalator, is equivalent to $130/MWh on a levelized basis for a 20-year term.

In Attachment A, the parties also acknowledged that certain key assumptions used by C&CR in developing its pricing in 2008 are undergoing further review to reflect current and future conditions prior to signing a term sheet. Key pricing factors include, but are not limited to: (1) wind production capacity factor, (2) availability of federal and state tax incentives, grants, and loan guarantees, (3) wind turbine capital costs, (4) financing costs, and (5) project costs including future cost of materials and site development and installation costs. Changes in these key pricing factors may justify higher or lower energy pricing.

Other attachments to the Letter Agreement included the community benefits committed to by C&CR, and Hawaiian Electric and MECO commitments to Lanai.

Some high-level economic analyses of connecting generation on other islands to the Oahu grid were conducted as part of the IRP process, and the results are summarized in *Chapter 11: Inter-Island and Inter-Utility Connection Analysis*. The cost of the cable system will be a fixed cost, regardless of the amount of energy transmitted using the cable system. The estimated capital cost of connecting the Oahu grid and a Lanai Wind Farm via a direct undersea cable link used in the analyses, at the high end of the range, was about $689 million, which translates to an annual cost of about $93,000,000 per year (including O&M). Assuming 774 GWh are produced and transmitted annually, the cable interconnection could add as much as 12 cents per KWh to the cost per KWh of the energy produced by a 200 MW wind farm on Lanai.

Previously, it was estimated that the cost of interconnecting a 200 MW wind farm on Lanai and a 200 MW wind farm on Molokai to the Oahu grid would be about 8 cents per KWh (that is, approximately $118,000,000 per year divided by the 1,480 GWh expected to be produced by the two wind farms). Assuming a cost of 13 cents per KWh for the wind farm energy, the all-in cost for the wind farm energy delivered to the Oahu grid was 21 cents per KWh. This is the estimated cost for the Lanai Wind Farm energy that was included in the IRP resource plan analyses for the various scenarios.

The separate, high-level analysis performed for Chapter 11 indicates that the cost per KWh for interconnecting a stand-alone 200 MW wind farm on Lanai to Oahu could be as high as 12 cents per KWh. However, the actual cost will depend on the design, installation cost and financing cost of a cable project acquired through a competitive procurement process. Costs common to both the cable and wind farm projects (such as the costs of improving the harbor and roads on Lanai) would likely be shared between the wind farm and cable projects. The cost of the wind farm itself could be reduced through negotiations to make the all-in cost for a combined cable and wind farm project competitive with other alternatives.

In summary: (1) Hawaiian Electric has a binding term sheet C&CR that governs components of a PPA that is still to be negotiated; (2) the Commission, in its "Big Wind Waiver Order", requires that for the waiver to apply, the Hawaiian Electric must provide the Commission with evidence in any application for approval of the PPA that the price paid is fair and in the best interest of the ratepayer, meaning that the PPA energy pricing needs to be a good deal for customers; and (3) the development of an undersea cable to support the Lanai Wind project is subject to selection of an undersea cable developer via a competitive process, or alternatively, another process approved by the Commission, in compliance with the Undersea Cable legislation.

Hawaiian Electric intends to continue to work with C&CR, or its assignee. Whether or not the Lanai Wind project goes forward is still subject to crossing many hurdles including execution of a PPA that is good for customers, selection and approval of a cable developer, and Commission approval of all agreements.

A Lanai Wind PPA based on the Lanai Term Sheet would be negotiated during the period allotted for conduct of the Commission-authorized RFP process, resulting in selection of (and filing of application for Commission approval of a proposed certified cable company, and proposed cable transmission tariff, so that the application for approval of the Lanai Wind PPA can be submitted on or about the same date as the Cable CPCN application.

A Lanai Wind PPA will have to include schedules and milestones, which must be synchronized with the schedule key development milestones for the Undersea Cable System and the Oahu Infrastructure. The schedule and milestones for the Undersea Cable System, which are expected to drive the development schedule and milestones for the other Inter-Island Wind Project Components, will be developed as part of the RFP process. The acceptance of the final Environmental Impact Statements (EIS), will be required, and the issuance of the Major Discretionary Permits for each "project" will have to be obtained before the developer of any Inter-Island Wind Project Component is required to proceed with commitments of expenditures for the acquisition and installation of the component equipment and facilities.

The certified cable company will be expected to assume financial responsibility for the Undersea Cable System until both the Undersea Cable System and the Lanai Wind Farm have achieved commercial operations. Similarly, C&CR will be expected to assume financial responsibility for the Inter-Island Wind Farms until both the Undersea Cable System and the Inter-Island Wind Farms have achieved commercial operations. In order to address project-on-project financing risk, C&CR may contract with developers of other Inter-Island Wind Project components, and may restructure the provisions regarding the rights to proceed, termination rights, step-in rights and other related rights and obligations.

Therefore, prior to execution of a PPA, the following must occur: (a) an IRS, taking into account the cable specifications and requirements in the Cable RFP, must be conducted; (b) a proposed Certified Cable Company must be selected pursuant to a Cable RFP; (c) a satisfactory cable transmission tariff must be accepted by the proposed Certified Cable Company; and (d) the proposed Certified Cable Company and C&CR must agree to a satisfactory allocation of project-on project financing risks, and satisfactory provisions in their PPAs and cable transmission tariff.

For a Lanai Wind PPA to be effective, the Commission will need to approve or certify each Inter-Island Wind Project Component, approve the community benefits and implementation steps for the community benefits that require Commission approval, and determine that the Inter-Island Wind Project (that is, the Undersea Cable System, Oahu Transmission Infrastructure and Lanai Wind PPA) would be a cost-effective means of helping the Hawaiian Electric Companies meet the RPS.

Renewable Energy and Undersea Cable System Oahu RFP

As a result of the July 14, 2011 Order issued in Docket No. 2009-0327, Hawaiian Electric submitted a request to the Commission to open a new docket for a Request for Proposals (RFP) for 200 MW or more of renewable energy to be delivered to the island of Oahu. On September 26, 2011, the Commission issued an order opening Docket No. 2011-0225 for this purpose.

In this docket, Hawaiian Electric filed a Draft Request for Proposals for Renewable Energy and Undersea Cable System Projects delivered to the Island of Oahu on October 14, 2011. (A revised draft was posted on September 28, 2012, and is referred to as the RFP, Oahu RFP or draft Oahu RFP.)

The competitive bidding process includes the following steps: (1) the utility designs a draft RFP, then files its draft RFP and supporting documentation with the Commission; (2) the utility holds a technical conference to discuss the draft RFP with interested parties; (3) the utility determines whether and how to incorporate recommendations from interested parties in the draft RFP; (4) the utility submits its final, proposed RFP to the Commission for its review and approval (and modification if necessary) according to the following procedure: (a) the Independent Observer (IO) selected by the Commission for the process (if any) submits its comments and recommendations to the Commission concerning the RFP and all attachments, simultaneously with the electric utility's proposed RFP; (b) the utility shall have the right to issue the RFP if the Commission does not direct the utility to do otherwise within 30 days after the Commission receives the proposed RFP and the IO's comments and recommendations.[89]

In an order issued October 14, 2011, the Commission identified Boston Pacific Company, Inc. as the IO for the RFP process. Hawaiian Electric held a technical conference in Honolulu on December 7, 2011, and accepted public comments on the Draft RFP through January 7, 2011. After receipt of comments on the Draft RFP from the IO and the general public, Hawaiian Electric participated in further review with the Commission, the Consumer Advocate and DBEDT in the months August and September 2011. Hawaiian Electric made additional revisions to the RFP documents and associated agreements and posted a Revised Draft RFP to the Hawaiian Electric's website (www.heco.com/renewableRFP) on September 28, 2011. The Proposed Final RFP has not yet been issued, and Hawaiian Electric expects to receive further guidance from the Commission before finalizing the RFP.

The competitive procurement process is intended to elicit bids that will enable Hawaiian Electric to obtain renewable energy generation at a competitive, reasonable cost with reliability, viability and operational characteristics consistent with Hawaiian Electric's long term energy planning and energy policy requirements and objectives as set forth in the RFP.

The RFP, as currently drafted, seeks proposals for the supply of qualified renewable energy to be delivered to the Hawaiian Electric System in accordance with the RFP. The proposed renewable energy generation resources must qualify under the RPS. The resources acquired through this Final RFP must have guaranteed commercial operations dates that are no later than December 31, 2023. Resources that can reasonably be expected to contribute to meeting the Hawaiian Electric Companies' RPS requirements in 2020 will be given additional credit.

[89] Framework, Part IV.B.6.e.

The RFP is for energy only, and no capacity payment will be paid for generation. The total amount of electric energy being solicited is approximately 600 to 800 gigawatt hours (GWh) annually, over a term of 20 years. On July 14, 2011 the Commission ordered Hawaiian Electric to issue an RFP requesting a minimum of 200 MW of renewable energy to replace 200 MW of the original 400 MW wind bid by the developer of the proposed Lanai Wind Farm (the Proposed Lanai Wind Farm). As the RFP is energy only, the 200 MW (minimum) needed to be converted to GWh for this RFP. The availability of wind and other intermittent renewable resources is highly variable. For simplicity, Hawaiian Electric has described the energy as 600 to 800 GWh per year, which equates to an availability of between 34% and 46%. As the Commission's request is for a minimum amount of energy, higher amounts of energy will also qualify.

If the proposed Lanai Wind Farm does not materialize for some other reason, then Hawaiian Electric may accept an additional 600–800 GWh (for a total of 1200–1600 GWhs) of qualified renewable energy to be delivered to the Hawaiian Electric System on Oahu. The amount of energy ultimately contracted for through the Final RFP will depend on factors such as (1) price, (2) system cost, (3) progress with other initiatives (such as projects under construction with approved PPAs, executed PPAs, PPAs in negotiations, and biofuels), (4) attributes of the energy projects and system impacts, and (5) net system loads on Oahu.

Hawaiian Electric will consider both On-Oahu and Off-Oahu renewable energy generation sources. Off-Oahu renewable generation must be delivered to the island of Oahu. In order that any such Off-Oahu renewable energy can be delivered to the Hawaiian Electric System, Hawaiian Electric also plans to solicit with the Final RFP proposals for a high-voltage inter-island transmission cable plus related converter stations, interconnection facilities and other infrastructure to connect such Off-Oahu renewable energy generation resource to the Hawaiian Electric System. Bidders may submit proposals for an Undersea Cable System that is independent of any Bid to deliver an Off-Oahu renewable energy generation facility, and may also propose an inter-island transmission cable as a combined resource with an Off-Oahu renewable energy generation facility.

The amount of undersea cable capacity required may vary based on the amounts and types of generation selected as a result of this Final RFP as well as the ability of the Hawaiian Electric System to absorb energy injected by the undersea cable.

The developer of the Undersea Cable System must become a Certified Cable Company by receiving a certification from the PUC as a public utility pursuant to HRS § 269-7.5. In reviewing and approving the Undersea Cable System Developer's application for a certificate of public convenience and necessity (CPCN), the Commission will take into consideration, among other factors, (1) the status of the PPAs pursuant to which renewable electrical energy will be generated on islands other than Oahu and transmitted to the Hawaiian Electric System via the Undersea Cable System, (2) the extent to which the Project-On-Project Financing Risk of the Undersea Cable System and the Off-Oahu Generator(s) is materially reduced through agreements between CCC and the owner or owners of the Off-Oahu Generator(s) holding the PPAs, or through common ownership arrangements, and (3) the extent to which CCC assumes financial responsibility for the Undersea Cable System until both the Undersea Cable System and the Off-Oahu Generator(s) have achieved Commercial Operations.

Prior to approving the application for a CPCN, the PUC is expected to hold a public hearing on each island that will be connected by the Undersea Cable System to obtain comments and input from the affected communities about the Undersea Cable System.

The resources Bid in response to the RFP could take any of the following forms:

- An "On-Oahu Generator Bid" is a Bid for a renewable energy generation resource located on the island of Oahu, or within three (3) nautical miles from the coast line (the line of ordinary low water) offshore of Oahu, that will connect directly to the Hawaiian Electric System.
- An "Off-Oahu Generator Bid" is a Bid for a renewable energy generation resource, not located on Oahu, that could reasonably reach the island of Oahu via an inter-island transmission cable. However, the inter-island transmission cable is not part of the Off-Oahu Generator Bid.
- An "Undersea Cable System Bid" is a Bid by an Undersea Cable System Developer to build a stand-alone inter-island transmission cable system to connect Off-Oahu Generator(s) to the Hawaiian Electric System.
- A "Combined Resource Bid" is a Bid for an Off-Oahu Generator combined with an inter-island transmission cable and associated facilities from the island on which such resource is located to the Hawaiian Electric System.

Hawaiian Electric will not consider Off-Oahu Generator Bids without a Bid for undersea cable capacity from the same island. As part of the evaluation process, Hawaiian Electric will pair Off-Oahu Generator Bids with Undersea Cable System Bids relying on locational, technical and economic Bid information, including the necessary transmission infrastructure improvements (both terrestrial and submarine) to deliver the energy produced to the Hawaiian Electric System, so that both generation and cable system proposals can be fairly evaluated on a competitive basis, including in comparison with Bids for On-Oahu Generators. The cost, timing and financial feasibility of the Undersea Cable System will be key factors in evaluating any Off-Oahu Generators.

Hawaiian Electric has signed a term sheet with Castle & Cooke Resorts, LLC (C&CR), as the result of its selection in Docket No. 2009-0327, to provide renewable energy generation resources from the proposed 200 MW Lanai Wind Farm to the Hawaiian Electric System, which will require an inter-island transmission cable to deliver the electric energy to the Hawaiian Electric System. One of the purposes of this Final RFP is to solicit such a cable connection from Cable Bidders and Combined Resource Bidders.

Some of the details with respect to the contemplated Undersea Cable System projects include:

1. An Undersea Cable System connecting the Maui and Oahu grids could be separate from a cable to Lanai to import energy from a Lanai Wind Farm to Oahu.
2. The Undersea Cable System developer will be fully responsible for the design, construction and cost of the Undersea Cable System project. The owner of the Undersea Cable System will have to be certified by the PUC as a certified cable company.
3. The Oahu Transmission Infrastructure to connect an Undersea Cable System connecting a generator to the Oahu grid or the Maui grid to the Oahu grid will be paid for, and constructed (with some exceptions), by the certified cable company, but would be designed by and transferred upon commercial operations to Hawaiian Electric. (In the case of an Undersea Cable System connecting the Maui grid to the Oahu grid, the Maui Transmission Infrastructure would be paid for, and constructed (with some exceptions), by the certified cable company, but would be designed by and transferred upon commercial operations to MECO.)
4. Following commercial operations, operational control of the Undersea Cable System will be transferred to Hawaiian Electric, but the certified cable company will continue to own, physically operate, maintain and repair the Undersea Cable System.
5. The certified cable company will be paid for providing cable capacity (and for providing and paying for the on-island transmission infrastructure) through a Cable Access Charge collected from Oahu ratepayers (in the case of an Undersea Cable System connecting a generator to the Oahu grid) or by Oahu and Maui ratepayers (in the case of an Undersea Cable System connecting the Maui grid to the Oahu grid).
6. The RFP provides that Hawaiian Electric would have the option to purchase an Undersea Cable System after 10 years.

These concepts are consistent with the provisions in Act 165 (Haw. Leg. 2012), which was passed by the 27th Hawaii Legislature on May 3, 2012, and was signed by the Governor on June 27, 2012. The effective date for the law is July 1, 2012. The purpose of the law is to establish the regulatory structure under which high-voltage electric transmission cable systems can be developed, financed, and constructed on commercially reasonable terms, such as those upon which successful cable projects have been undertaken in New York, California, and around the world.

Bids will be assessed to determine the likelihood of a project coming to fruition based on various factors critical to successful project development. The development plan and actions to date by the bidder, as well as the likelihood of timely project completion, will be evaluated through an evaluation of multiple factors that contribute to the success of project development feasibility. The objectives of the project development feasibility criteria are to provide an indication of the feasibility and viability of each project (or the generation and components of a Combined Resource) and the likelihood of meeting the preferred Commercial Operations Date. Hawaiian Electric prefers bids from bidders that can demonstrate, based on the current status of project development and past experience, that the project will likely be successfully developed as proposed.

For Off-Oahu Generator Bids or Undersea Cable System Bids, a detailed assessment of the issues associated with project-on-project financing risk and mitigation strategies proposed within each such bidder's project plan to address such risk, including any coordination agreements with other bidders or financial requirements from other bidders such as liquidated damage provisions or performance security provisions.

As set forth in the Competitive Bidding Framework, the process leading to the distribution of the RFP includes, (1) the filing of a Draft RFP with the Commission (which occurred on October 14, 2011), (2) a technical conference to discuss the Draft RFP with interested parties including potential bidders (which occurred on December 7, 2011), (3) the submission of comments on the Draft RFP to Hawaiian Electric and the Commission (which occurred through January 7, 2012), (4) the decision by Hawaiian Electric (in conjunction with the Independent Observer) on whether and how to include recommendations from interested parties, and (5) the submission of the Final RFP to the Commission for approval and potential modification. Hawaiian Electric received, considered, and incorporated a number of changes into the Draft RFP as a result of comments and questions from interested parties, and posted the revised Draft RFP on September 28, 2012, along with detailed responses to the comments and questions.

Hawaiian Electric's Firm Capacity Request for Proposals

The determination of Hawaiian Electric's adequacy of supply is made by applying its capacity planning criteria. Hawaiian Electric's capacity planning criteria are described in its annual Adequacy of Supply (AOS) letter. Hawaiian Electric's capacity planning criteria are provided in Appendix L of this IRP filing. When a determination is made that additional firm capacity will be needed to satisfy Hawaiian Electric's capacity planning criteria, such capacity must be acquired in accordance with the Commission's Framework for Competitive Bidding.

As described in Hawaiian Electric's most recent AOS letter, submitted to the Commission on March 28, 2013, the need for additional firm capacity is function of a number of key inputs, such as:

- Forecast of peak demand, including the peak reduction benefits of load control programs;
- Equivalent Forced Outage Rate Demand (EFORd) on the generating units;
- Planned maintenance schedules for the generating units on the system;
- Additions of firm generating capacity; and
- Reductions of firm generating capacity.

Among the potential additions of firm capacity are the Schofield Generating Station and the addition of a steam turbine to CIP CT-1 to form a single train combined cycle unit. These two items are discussed further below.

On August 1, 2012, in D&O No. 30552, the Commission granted, subject to conditions, Hawaiian Electric's request for a waiver from the Framework for Competitive Bidding for the proposed Schofield Generating Station project.[90] The project would add approximately 50 MW-net of firm generating capacity. The PUC identified a number of questions and concerns that will need to be addressed in an upcoming application to the Commission requesting approval to commit funds for the project. It is anticipated that, subject to the Commission's approval of Hawaiian Electric's application for approval to expend funds for the project, construction may occur in the 3rd quarter of 2016, with a forecasted in-service date of the third quarter of 2017.

The IRP analysis pertaining to one of the Commission's principal issues regarding the highest and best use of CIP CT-1 indicates that it would be beneficial to ratepayers if a heat recovery steam generator and a steam turbine are added to CIP CT-1 to form a single train combined cycle unit. The Campbell Industrial Park Steam Turbine #1 (CIP ST-1) project could add approximately 55 MW-net of firm capacity to the Oahu energy system. This project will not only add 55 MW-net of capacity to the system, but will effectively result in 168MW of "new" high-efficiency baseload/cycling capability. Conversely, there will be a reduction of 113MW of peaking capability. Hawaiian Electric plans to seek a waiver from competitive bidding pursuant to Section II.A.3.c.(i) (the expansion or repowering of existing utility generating units) for this project. The Commission may waive the competitive bidding framework or any part thereof upon showing that the waiver will likely result in a lower cost supply of electricity to the utility's general body of ratepayers, increase the reliable supply of electricity to the utility's general body of ratepayers, or is otherwise in the public interest. Depending on the Commission's approval of Hawaiian Electric's request for waiver from the competitive bidding framework as well as on the Commission's approval of Hawaiian Electric's request to expend funds for the project, construction could begin in early 2017, with an anticipated in-service date of late 2018.

In addition, Hawaiian Electric will determine the extent to which as-available wind generating from Kahuku and Kawailoa can provide equivalent firm capacity value to the system.

Among the potential reduction in firm generating capacity are the deactivation of the Honolulu Power Plant (HPP) and Waiau Units 3 and 4 and the potential termination of the Hawaiian Electric-Kalaeloa Partners, L.P. (KPLP) power purchase agreement (PPA) in May 2016.

The extent to which Hawaiian Electric will need additional firm capacity will depend on the particular combination of capacity additions and capacity reductions. The Schofield Generating Station could add 50 MW-net and the

[90] Hawaiian Electric submitted its application for waiver on December 27, 2011, in Docket No. 2011-0386.

CIP ST-1 project could add another 55 MW-net. Deactivation of HPP would reduce the amount of firm capacity on the system by 107 MW-net. Deactivation of Waiau Units 3 and 4 would further reduce firm capacity by 93 MW-net. The KPLP PPA provides 208 MW-net to the system.

Based on deactivating/decommissioning HPP and Waiau units in 2014 and 2017, respectively, in which 200 MW-net would be lost from the system, Hawaiian Electric will need replacement capacity in 2018. Hawaiian Electric plans to be able to reactivate the units if the system experiences unanticipated changes in peak demands or unit availability.

If Honolulu units 8 and 9 are deactivated in 2014 and reactivated in 2017, and Waiau units 3 and 4 are deactivated in 2017, CT-1 converted to combined cycle in 2017, Schofield added in 2017, Honolulu decommissioned or retired in 2018, and no other decommissioning of the remaining firm capacity resources, the IRP scenario analysis indicates that there is a possibility of very limited new capacity need after that.

Hawaiian Electric will be willing to acquire additional more efficient and more flexible, replacement generation for economic reasons (that is, to reduce the cost of generating electricity from dispatchable generation on Oahu) and deactivating more Hawaiian Electric units. That is more likely to be the case if LNG is available, which is estimated to be in 2020.

Hawaiian Electric currently is negotiating with KPLP, whose PPA extends to May 2016, under an exemption from competitive bidding.

Based on the foregoing, Hawaiian Electric plans to issue an RFP for up to 200 MW of firm, dispatchable generation in 2015–2016 allowing time to post the draft, hold a technical conference and issue the proposed final RFP. The amount of capacity that may actually be acquired via the RFP will depend on the cost of the new generation, fuel (if LNG is available), need for additional firm capacity (depending on what happens with Schofield, CIP ST-1 and KPLP), system demand and ancillary services requirements to further integrate as-available variable generation resources. The RFP would specify that new generation have multi-fuel capability for biodiesel, diesel, and LNG. The new firm capacity would need to be in service by the 2020 time frame, assuming that KPLP is no longer providing capacity and energy to Hawaiian Electric, HPP and Waiau Units 3 and 4 have been reactivated, and Schofield Generating Station and CIP ST-1 are in service by 2018. Once the new firm capacity is in service, consideration can be given to deactivating HPP and Waiau Units 3 and 4.

Hawaiian Electric plans to further evaluate its need for firm capacity and the timing and size of an RFP for firm capacity in its next Adequacy of Supply filing.

The attributes of the generation would include attributes such as, but not limited to:

- The capacity to be provided may come from multiple generating units;
- Each generating resource must provide firm capacity;

- Each generating resource must be dispatchable between its minimum and maximum range by Hawaiian Electric;
- The size, in MW, of anyone generating resource shall not exceed 150 MW;
- The input energy (such as the fuel supply) to the generating units must be renewable and sustainable under the RPS;
- Each Generator able to operate on multiple fuel types to switch when the lowest priced fuel type changes;
- Each generating resource must be quick-starting, that is, the time between the start signal and synchronizing the generator to the system, closing the breaker and reaching minimum load shall be 10 minutes or fewer; quick-start units, after having attained minimum load, must be immediately available to be ramped up to full load operation and meet all environmental requirements for operation up to full load.
- Each generating resource must be able to cycle on and off multiple times per day;
- Each generating resource must be able to help regulate voltage;
- Each Generator must be able to help regulate and stabilize (via droop) the system frequency. The unit should be capable of setting and operating with a 4% droop characteristic;
- Each generating resource must be able to increase or decrease their power output at a rate equal to or greater than 5 MW per minute;
- Each generating resource must use commercially available and proven technology;
- Each generating resource site must have black-start capability (that is, capable of starting up on a completely de-energized utility grid).

Changes in Acquisition Methods

One of the most substantial methods to reduce customer bills is to change the way energy is procured. When considering cost-effective energy options for customers in Hawaii, the following needs to be discussed and considered:

- Provide a competitive procurement option for renewable energy projects designed to lower costs to consumers, create a competitive renewable energy market in Hawaii, and provide better value to customers.
- Evaluate competing renewable energy projects on the basis of overall value including favorable characteristics allowing displacement of conventional fossil plants, or negative impacts requiring additional support services from the power system. (that is, dispatchable, firm capacity, frequency responsive vs. non-dispatchable, variable, causes imbalance).
- Develop a flexible procurement mechanism to identify the competitive market price for renewable energy in Hawaii and to take advantage of market opportunities as they arise.
- Provide a regularly scheduled and timely process for bidders to compete to sell renewable power in Hawaii and to provide opportunities for project developers to continue to develop their projects through proper market signals.
- Assist Hawaiian Electric, MECO and HELCO to meet RPS targets in a systematic and orderly manner in conformance with electric system expansion requirements.
- Develop a process designed to reduce transaction costs for developers and the utility.
- Consider the unique constraints of Hawaii in the development of procurement mechanisms, which are the result of the State's isolation, such as:
  - Limited market
  - No ability to import/export energy
  - Existing levels of variable/renewable energy

The renewable energy environment has evolved since the Energy Agreement was signed back in 2008. In this new environment where circuit and system capacity is increasingly constrained, and costs to customers are increasingly of concern, the Companies' procurement mechanisms must comprehensively work to most efficiently and cost effectively fulfill the utilities' renewable energy needs wherever possible. This would include procuring those resources which provide the best fit at the least cost whenever possible.

Procurement mechanisms in other states have resulted in cost effective renewable savings for the customers. For example:

- In California, the utilities participate in the Renewable Auction Mechanism (RAM) solicitation program mandated by the California Public Utilities Commission (CPUC). The program has resulted in selection of variable renewable generation projects (2-20MW in size) that resulted in PPAs at $0.089 per KWh. The success in the program's ability to achieve cost effective energy for their customers can be attributed to the following:
    - Shorter solicitation process (approximately 6 months)
    - Standard PPA contract
    - 30 day regulatory approval for the PPA
- In Arizona, Arizona Public Service (APS) conducts periodic Small Generation RFPs for variable renewable generation project (2-15MW in size). APS' solicitation resulted in PPAs with pricing well below $0.13 per KWh. The success in APS' program's ability to achieve cost effective energy for their customers can be attributed to the following:
    - Shorter solicitation process (approximately 6 months)
    - Maximum Bid Price requirement that was set at $0.13 per KWh
    - Minimal regulatory oversight for the PPA

Hawaiian Electric has recently taken steps towards a more flexible and adaptive procurement environment, including the recent Reexamination Report of Tiers 1 and 2 of the FIT Program (Docket 2008-0273) filed in March 2013 and the Invitation for Low Cost Renewable Energy Projects on Oahu through Request for Waiver from Competitive Bidding.

In the FIT Reexamination Report, the Companies are proposing that a form of competitive bidding could be made a part of the FIT program so that ratepayers have some assurance that they are not overpaying for FIT capacity. The future FIT program would establish a price adjustment mechanism based on actual market conditions, similar to the Renewable Market Adjusting Tariff (Re-MAT) process being undertaken in California for its FIT program.

As described above, in February 2013, Hawaiian Electric issued a call for low-cost renewable energy projects on Oahu that could qualify for a waiver from competitive bidding. Hawaiian Electric narrowed the responses to five projects based on prices and other criteria such as site control and development experience. Combined, the projects will sell electricity to Hawaiian Electric at an average price of 15.9 cents per kilowatt-hour. This is about one-third less than prices paid to existing solar and wind energy projects on Oahu.

HELCO Acquisition of Generation Resources

Exempt Projects

PGV Expansion

HELCO modified its PPA with PGV in February 2011, in order to acquire an additional 8 MW of firm, dispatchable, geothermal energy generation. During negotiations, HELCO insisted that the additional 8 MW have the same characteristics as HELCO's own steam generating plants, so that the addition would provide the same grid management capability as HELCO's units.

HELCO modified its PPA (the Existing PPA) with PGV to (1) allow PGV to expand the capacity of its geothermal facility by 8 MW,[91] (2) to allow PGV to firm up its ability to provide the energy and capacity committed under its Existing PPA, (3) to incorporate important new operation and performance requirements, and (4) to reduce and fix the energy rates for some of the energy supplied by PGV under the PPA, as amended (the Modified PPA).

This was accomplished through two agreements, including a fifth amendment to the Existing PPA, and a new 8 MW Expansion PPA. The Commission approved the two agreements in December 2011. Under the two agreement structure, PGV is making the improvements and modifications (the Expansion Project or Expansion Facility) necessary to expand its facility to provide 38 MW of energy and firm capacity, and to meet certain operational, performance and dispatch requirements that were not required under the Existing PPA. In return for allowing PGV to supplement the Existing Facility, PGV agreed to delink the energy price paid for certain amounts of energy under the existing PPA from oil prices. The renegotiated pricing for the 25–30 MW on-peak, 22–27 MW off-peak block is $118/MWh, as well as a $504,750 capacity payment. The 8 MW expansion is priced at $90/MWh for the first 30,000 MWh in a year, and $60 for every MWh HELCO might purchase thereafter, as well as a capacity payment of $2,000,000. The term of the 8 MW expansion is set to run through 2027, along with the original PPA. The PUC approved the application on December 30, 2011 in Decision & Order 30088. The expansion was completed and placed in service on March 19, 2012.

One of the significant benefits of the Modified PPA is that PGV agreed to provide important ancillary dispatch services not found in other types of renewable energy projects, such as remote dispatch control in the range of 22 to 38 MW, voltage regulation at the point of interconnection, under-voltage

[91] Under this expansion, PGV added 11 MW of capacity via new wells and generators, but HELCO was only obligated to take 8 MW; the other 3 MW could go towards supplementing existing contracted energy and capacity.

and over-voltage ride through capability, under-frequency and over-frequency ride through capability, automatic reduction of power during high-frequency conditions, and 3MW of quick load pick up under specified conditions.

HELCO Waivered Projects

Hu Honua

HELCO has entered in a PPA (subject to PUC approval) with Hu Honua to acquire 21.5 MW of firm, dispatchable, biomass energy generation.

HELCO and Hu Honua entered into a Power Purchase Agreement for Renewable Dispatchable Firm Energy and Capacity, dated May 3, 2012, (Hu Honua PPA) that provides HELCO with a 20-year firm, dispatchable, renewable energy generating resource. Hu Honua will refurbish an existing sugar plantation boiler with steam turbine and generator, retrofit with modern emissions control equipment, and it will be fired primarily with biomass fuel (wood chips) and supplementally fired with biodiesel fuel. The Hu Honua facility will have a dispatchable load range from 7 MW to its Available Capacity (which could be greater than or less than its Committed Capacity of 21.5 MW) and will operate continuously when available for utility dispatch.

The Hu Honua facility will provide performance and operational features beneficial to system reliability, similar to the capabilities of the existing steam generation, including (1) provision of firm dispatchable energy, (2) inertial and primary frequency response, (3) regulation and load following under HELCO's control, (4) voltage regulation, and (5) ability to ride through frequency and voltage disturbances. In general, the Hu Honua facility will behave like a utility steam generating unit with the benefit of being renewable dispatchable firm capacity for the HELCO grid. The dispatch of the Hu Honua facility will generally be determined through economic dispatch, based upon the energy pricing; as influenced by system constraints, demand, relative cost to other generation options, and frequency regulation requirements.

If the PPA is approved, HELCO expects that the facility can begin commercial operations in 2014.

HELCO Requests for Proposals

HELCO Geothermal RFP

HELCO has initiated a Geothermal RFP process to acquire additional firm, dispatchable, geothermal energy generation.

On June 22, 2011, HELCO issued a Geothermal Request for Information for Geothermal Power Development Island of Hawaii (Geothermal RFI). One of the key outcomes of the Geothermal RFI was that geothermal developers advocated pursuing an expedited competitive bidding docket schedule in the 2012–2014 time frame.

On May 1, 2012, at HELCO's request, the PUC opened Docket No. 2012-0092 for the purpose of receiving filings, reviewing approval requests, and resolving disputes, if necessary, related to HELCO's plan to proceed with a competitive bidding process to acquire approximately 50 MW of dispatchable renewable geothermal firm capacity generation on the Island of Hawaii (the Geothermal RFP). The Geothermal Firm RFP is being conducted pursuant to the Framework for Competitive Bidding.

The goals of the Geothermal RFP are to (1) encourage the exploration, identification, evaluation of geothermal resources on the Island of Hawaii and to develop such resources in a way that assists the Island of Hawaii in reducing its reliance on fossil fuels while allowing for the integration and management of intermittent renewable resources (such as wind and solar power) and maintaining system reliability, and (2) successfully obtain geothermal firm capacity generation (with a commercial operation target date in the 2018 to 2023 time frame) with operating performance characteristics (including controlled dispatch, voltage regulation, frequency regulation, and redundancy to maintain system reliability) similar to HELCO's oil-fired generation plants at a lower overall system-wide operation cost to HELCO's customers.

The Final Geothermal RFP was issued on February 28, 2013, and six bids were received on April 30, 2013. The evaluation process described in the Geothermal RFP is in progress, with oversight of the Independent Observer hired by the PUC. Upon completion, HELCO will rank the bids and select one or more bids in the Final Award Group that will proceed with the Interconnection Requirements Study (IRS) and PPA negotiations.

Negotiation of Fixed Price Contracts

The energy prices in new PPAs, like the energy pricing in the Hu Honua PPA, is not and will not be linked to fossil fuel prices. HELCO is trying to renegotiate the energy pricing in existing PPAs with NUGs to de-link the energy pricing in those PPAs from fossil fuel prices.

Under the federal Public Utility Regulatory Policies Act of 1978 (PURPA), and the regulations implementing PURPA, electric utilities like HELCO were required to offer to purchase power from "qualifying facilities" at "avoided costs". As a result, the PPAs incorporate energy payment rates based on HELCO's filed short-run avoided energy cost rates, which are determined in accordance with a methodology approved by the Commission.

In December 2004, however, MECO successfully negotiated a PPA with Kaheawa Wind Power, LLC (KWP), in which 70% of the payments for energy that MECO made to KWP were based on a fixed payment rate. Then, in 2006 (pursuant to Act 162), the Hawaii Legislature recognized the benefits of this type of pricing arrangement and amended Section 269-27.2 of the Hawaii Revised Statutes to require the Commission to establish a methodology to remove or significantly reduce any linkage between the price of fossil fuels and the rate paid for the non-fossil fuel generated electricity. Since that time, negotiated PPAs for renewable energy from wind and solar PV facilities have reflected a 100% delinking of the energy payment rates from oil prices.

The Hawaiian Electric Companies asked all of their IPPs with energy payment rates based on filed short-run avoided energy cost rates to renegotiate their energy payment rates. KWP agreed to fix the payment rates for the remaining 30% of the payments for energy that MECO makes to KWP, and the Commission approved the amendment reflecting that agreement in April 2012. In addition, when PGV entered into an agreement to add 8 MW of new capacity, it also agreed to fix the payment rates for some of the energy supplied under its 30 MW PPA (although much of the energy is still paid for based on filed short-run avoided energy cost rates).

In the Commission's Decision and Order (D&O) approving the PGV expansion, the PUC encouraged HELCO and PGV to amend the original PPA to change the pricing for the first 25 MWs on-peak, first 22 MW off-peak from one based on filed avoided energy costs to a fixed price. (The annual capacity payment of $4,000,000 for this block would not necessarily change.) The original PPA runs through 2027. HELCO and PGV have been in negotiations since the PUC's D&O was issued.

HELCO initiated follow up discussions with PGV with the goal of converting the energy payment rates for energy in PGV's first "tier," up to 25MW on-peak and up to 22MW off-peak, from filed short-run on-peak and off-peak avoided energy cost rates to a fixed rate. HELCO also sent request letters on July 20, 2012 (building on the earlier requests) seeking to renegotiate and fix the energy payment rates in their PPAs to:

- Wailuku River Hydroelectric LP: a 12.1 MW run-of-the-river hydroelectric facility with a PPA effective March 6, 1991 with a contract term of 30 years.
- Hawi Renewable Development, LLC: a 10.56 MW wind facility with a PPA effective May 19, 2006 with a contract term of 15 years.
- Tawhiri Power, LLC: a 20.5 MW wind farm with a restated and amended contract effective April 3, 2007 with a contract term of 20 years.

Discussions are on-going.

MECO Acquisition of Generation Resources

MECO Grandfathered Projects

MECO has three PPAs with wind farms on Maui, including Kaheawa Wind Power (KWP): 30 MW,[92] Kaheawa Wind Power II (KWP II): 21 MW,[93] and Auwahi Wind Energy (Auwahi): 21 MW.[94] The KWP II and Auwahi wind farms were grandfathered projects.

MECO's system cannot currently accommodate all of the power generated by KWP II, and it was known as a result of the very detailed KWP2 Wind Integration Study (WIS) conducted by General Electric Company, Inc. (GE) that there would be substantial curtailment with three large wind farms added to the Maui system, even with the introduction of new and innovative mitigation measures analyzed in the WIS. MECO has taken significant steps (above and beyond normal PPA requirements) to take more energy from intermittent resources, and is committed to taking more steps based on newer studies (in some cases, after further analyses recommended by the studies).

Maui Wind Integration Study

The G.E. KWP2 Wind Integration Study (WIS) was a joint effort by MECO and First Wind Hawaii (FWH), developer of the KWP II project, and was completed as of June 2010.[95]

The WIS used existing operating data from the MECO system, as well as modeled wind power data, to examine the probable effects during the 2011 model year of accepting energy from different combinations of (i) KWP I (30 MW), (ii) the Auwahu Wind Farm at Ulupalakua Ranch and/or (iii) KWP II. The WIS estimated that the MECO system could accept less than one-third

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[92] Pursuant to the Power Purchase Contract For As-Available Energy dated December 3, 2004, between MECO and Kaheawa Wind Power, LLC (KWP), as amended by Amendment No. 1, dated August 8, 2011, as amended by the First Amendment dated August 8, 2011, MECO purchases energy from a 30 MW wind farm located at Kaheawa Pastures, Ukumehame, Maui, on State conservation land. KWP began delivering energy to MECO on June 9, 2006.

[93] Pursuant to the Power Purchase Agreement For As-Available Renewable Energy dated September 20, 2010, between MECO and Kaheawa Wind Power II, LLC (KWP II), as amended by the First Amendment dated October 4, 2010, MECO purchases energy from a 21 MW wind farm facility located on a portion of the Government (Crown) Land of Ukumehame, Lahaina, and Wailuku, on the Island of Maui. The KWP II wind farm was placed into commercial operation on July 2, 2012.

[94] Pursuant to the Power Purchase Agreement For As-Available Renewable Energy dated January 25, 2011, between MECO and Auwahi Wind Energy LLC (Auwahi), MECO purchases energy from a 21 MW wind farm located almost entirely on Ulupalakua Ranch, in the Hana, Kula and Kihei Districts, on the Island of Maui. The Auwahi Wind Energy LLC wind farm was placed into commercial operation on December 28, 2012.

[95] The WIS is described in Exhibit 12 to the KWP II PPA approval application filed October 4, 2010 (and re-submitted October 22, 2010) in Docket No. 2010-0279.

of the total GWh that was expected to be made available from KWP II.[96] Based on these results, MECO and FWH sought to determine what, if any, infrastructure and operational modifications could be implemented to increase the amount of energy that the MECO system could potentially accept from the KWP II Wind Farm within acceptable levels of reliability. The additional infrastructure and operational modifications were called the "mitigation measures" or Maui Operational Measures (MOMS).

The purpose of the MOMS is to increase the penetration of wind energy on MECO's system to the benefit of both the KWP II Wind Farm (as the WIS estimated that implementation of the mitigation measures should increase the energy that could be accepted from KWP II's Wind Farm in 2011 to 42 GWh) and the two other wind farms interconnected to or to be interconnected to MECO's system with curtailment priority superior to the KWP II Wind Farm. Given the results of the WIS, however, it was clearly understood by all that there would be substantial curtailment of KWP II even with implementation of the MOMS.[97]

From a planning perspective, it did not make sense to add another 21 MW wind farm to a system with the KWP I and Auwahi Wind Farms. From a risk transfer perspective, it would not have been prudent for MECO, on behalf of Maui customers, to accept the obligation to pay for curtailed energy from the KWP II facility. However, the final negotiated arrangement, under which KWP II accepted responsibility for providing certain ancillary services using a Battery Energy Storage System (BESS) sized for that purpose, agreed to be curtailed during excess energy situations, and accepted the risk that the electricity "market" on Maui may not grow as much as expected or may even decline, does make sense for Maui customers. Moreover, the tiered pricing structure in the KWP II PPA creates the possibility of a win-win situation in the future if the Maui system can accommodate more of the KWP II output in the future than was estimated.

It also was understood that the level of curtailment would be higher if system sales decreased instead of increased. With implementation of the MOMS, the PPA assumption is that MECO would be able to purchase 42 GWh (that is, less than one half) of the total GWh assumed to be made available by KWP II, assuming a net to system energy amount of 1,215 GWh for the year. The assumed purchase amount is reduced if the net to system

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[96] The estimates underlying the WIS were understood to be highly dependent on the underlying forecasts and assumptions for the model year, a number of which are subject to significant variability. For this reason, the PPA explicitly recognizes that "a number of factors may impact how much energy Company will be able to accept from the Facility in a Calendar Year, such as (but not limited to) the Net System Energy, the satisfaction of the BESS Condition Precedent so the Company is able to rely the BESS to meet Up Reserve and Down Reserve requirements, Company's implementation of the MOMS or MOMS Alternatives, the amount of energy delivered to Company's System from wind farms with higher curtailment priority than (that is chronological seniority to) the Facility, and the amount of energy made available to Company by Seller (that is, the Qualifying Possible Energy)." See §29(b)(1) of the PPA.

[97] PPA §8(i) explicitly states: "If Seller's Facility is in the Third Curtailment Position [that is, if the Auwahi Wind Farm goes into service as planned], the Parties understand and expect that the Facility's output will be curtailed due to Excess Energy conditions.

energy amount is less, since the ability of the system to accept the energy would be reduced.[98]

Maui Operational Measures

As a result of the study, and the concurrent PPA negotiations, the KWP II PPA incorporated specific Maui Operational Measures (MOMS),[99] described in Exhibit 11 to the KWP II PPA approval application. The five MOMS include (1) reduction of MECO System Must-Run Rules for Kahului Generating Station Unit 1 (K1) and Unit 2 (K2), (2) limiting system up reserves, (3) allocation of a portion (up to 10 MW) of the up reserve to the BESS, (4) allocation of a portion (up to 3 MW) of the down reserve to the BESS, and (5) AGC modifications to integrate the BESS for frequency execution and contribution to Up Reserve and Down Reserve.[100]

The MOMS that were agreed to required significant reconfiguration of MECO's Automatic Generator Control (AGC) to incorporate the KWP II Battery Energy Storage System (BESS) in providing certain ancillary services, a here-to-date unprecedented step. See Appendix W to KWP II PPA.[101] In recognition of that fact, the PPA provided up to a year to implement certain measures. See Appendix Z to KWP II PPA.

MECO was obligated to implement the K1/K2 MOM on the KWP II Commercial Operations Date, but implemented this step much earlier. The remaining MOMS were implemented sequentially as provided for in the PPA,[102] after demonstration (through testing) that the BESS was integrated into the operations of the KWP II Wind Farm and was able to provide the required Up Reserve, Down Reserve, frequency regulation and respond to AGC signals, and successful testing and demonstration of the AGC functionality. This has essentially all been accomplished within the one-year period provided in the PPA.

MECO has taken significant steps (above and beyond normal PPA requirements) to take more energy from intermittent resources. These include the Maui Operational Measures (MOMS), measures taken earlier after the KWP wind farm went into commercial operation in 2006, and measures implemented since then that go beyond the MOMS.

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[98] WP II PPA, Table D-2. In 2012, the actual net to system energy amount was 1154 GWh (due to the exponential growth in PV installations and other factors affecting sales on Maui). The Adjusted Energy Target would have been 29.8 GWh for 2012.

[99] The results accepted by MECO and FWH are incorporated into the PPA as the BESS Performance Standards (in Section 1.a(5) of Appendix X) and the Maui Operational Measures (MOMS) (in Section 2.a of Appendix X to the KWP II PPA).

[100] The five MOMS are set forth in Section 2.a of Appendix X of the PPA.

[101] The modifications included (1) configuring the AGC (a) so that it will adjust the minimum power settings of MECO's combustion turbines to account for the BESS' ability to meet MECO's Down Reserve requirement, based on a signal provided from the KWPII Wind Farm BESS, and (b) to control the KWPII Wind Farm and the BESS as separate units, (2) configuring the economic dispatch function in the AGC to meet the revised Up Reserve requirement, and (3) implementing in the AGC an automatic curtailment protocol among multiple generating system assets.

[102] Appendix Z (Test Verification for MOMS' Implementation).

MECO is committed to taking more steps based on newer studies (in some cases, after further analyses recommended by the studies). These studies have been conducted with the active participation and support of MECO and Hawaiian Electric. Some of the key studies include:

- The KWPII Wind Integration Study (WIS), prepared by General Electric and dated June 2010 (which is discussed above).
- The Operational Flexibility Study for the Integration of Renewable Energy, Phases 1 and 2 (Stanley Studies), prepared by Stanley Consultants, Inc. The final Stanley Phase 1 Study was dated February 2011 and the final Stanley Phase 2 Study was dated December 12, 2012.
- The Maui Energy Storage Study (Sandia Study), prepared by Sandia National Laboratories and dated November 2012.
- The Hawaii Solar Integration Study (HSIS), prepared by GE Consulting for the National Renewable Energy Laboratory, the Hawaii Natural Energy Institute, Hawaiian Electric and MECO, and dated March 25, 2013.
- The Generation Reserves/Cycling Study (Cycling Study), prepared by Electric Power Systems, Inc. (EPS)/Intertek /Aptech and dated May 30, 2013 in its current iteration.
- The Kahului Power Plant Reduced Operation: Transmission System Impact and Requirements (KPP Transmission Study), prepared by Hawaiian Electric's Transmission Planning Division and dated March 7, 2013.

The studies have looked at possible steps to see if operating practices (such as the amount of up reserve required) can be modified (while maintaining system stability and security) or mitigated (for example, using forecasts of wind energy), and whether generating units can be modified to reduce the amount of must run units on the system during minimum load periods or to increase the operating reserve capabilities of the units (so that fewer units are needed on line). For example, the Cycling Study focused on identifying the minimum generation configurations to meet the system requirements for (1) stability, (2) loadshed events, (3) rate-of-change-of-frequency, (4) regulation capacity, (5) generation ramping, and (6) voltage/transmission constraints.[103] Regulation capacity is the amount of unloaded generation available to ramp to meet the requirements of the system. If the minimum loads on the units that are run to provide these ancillary services can be reduced, then there will be more head room for intermittent renewables during minimum load periods (because the loading of must run units can be reduced), and there will be more head room for intermittent renewables during other periods (because fewer units need to be on line to provide up reserves).

[103] As is indicated in the Cycling Study, MECO's existing thermal (that is, firm) generating units provide the bulk of the regulation, spin, and dynamic response for the Maui system, especially during transient events. The displacement of these functions by other generation must be evaluated to ensure system stability, reliability, and customer service are not adversely impacted or, if there are adverse impacts, possible mitigating measures need to be identified.

System Improvement and Curtailment Reduction Plan

In its final decision in the 2012 test year rate case for MECO, Decision and Order No. 31288 (D&O No. 31288 or D&O) filed May 31, 2013, the Commission required that MECO provide, within 90 days of the date of the D&O, "a detailed strategy and action plan to: (1) improve operational efficiency, and (2) reduce curtailment of renewable energy ('System Improvement and Curtailment Reduction Plan')."

The tiered pricing structure in the KWP II PPA (and the Auwahi PPA) provides an opportunity to reduce energy costs for Maui customers if cost-effective changes can be made in the Maui system to permit the acceptance of more wind energy. It cannot be assumed, however, that changes will be cost-effective. In its plan, MECO will compare the key potential options taking into account the most recent changes in Maui's generating system, updated forecasts of energy and load, updated information on the status of HC&S, and the plan to retire the Kahului Power Plant at the end of 2018.

MECO Waivered Projects

Mahinahina Waiver

On May 10, 2013, MECO filed an Application in Docket No. 2013-0114 for approval of a waiver from the Competitive Bidding Framework to conduct negotiations towards a power purchase agreement between Anaergia Services and MECO for 4.5 to 6.0 MW of firm, dispatchable, biogas energy generation. The Mahinahina Energy Park, LLC project (the Mahinahina Project) will produce energy using biogas derived from Sorghum crops irrigated with recycled wastewater from the County of Maui's Lahaina Wastewater Reclamation Facility (LWRF). The Mahinahina Project is an agricultural energy project proposed to be located adjacent to the LWRF on agricultural zoned parcels owned by Maui Land & Pineapple Company and the Department of Hawaiian Home Lands.

The County of Maui (the County) supports the Mahinahina Project and has identified it as a possible means to address the County's need to dispose of reclaimed water in an environmentally safe and sustainable manner. In addition, the project affects the resolution of a lawsuit related to the County's current method of disposal of treated water from the LWRF, which was brought against it by Earthjustice.

MECO's Application seeks a waiver under Part II.A.3.c.(iii) of the Competitive Bidding Framework on the basis that the proposed project will meet the County's governmental objective of environmental compliance and minimizing litigation expenses for the County. In addition, the Mahinahina Project would benefit MECO's customers in that it is intended to increase the utility's reliable supply of clean, renewable energy. MECO's Application is currently pending before the Commission.

Future MECO Waiver Requests

Hawaiian Commercial & Sugar Company (HC&S) currently operates under the following conditions:

Capacity:
8 MW Off-Peak
12 MW On-Peak
4 MW interruptible load

- Payments of $1,790,880 annually (no escalation)

Energy: On and Off Peak energy pricing based on MECO monthly avoided cost filing (Docket 7310).

Under an agreement between MECO and HC&S, either party must provide a minimum of 18 months' notice to terminate the PPA. MECO and HC&S have agreed not to provide a notice of termination of the PPA such that the PPA could end no sooner than December 31, 2014. The PPA could continue on a year to year basis if neither party terminates the PPA. For planning purposes, MECO is assuming that HC&S will cease to provide capacity and energy to MECO after December 31, 2014.

MECO and HC&S have been in discussion to possibly modify the PPA and/or extend the term of the PPA. Any agreement of this nature would need to be favorable for the MECO customers and be in accordance with the Competitive Bidding Framework, which exempts qualified facilities and non-fossil fuel producers with respect to (among others):

- PPA extensions for three years or less on substantially the same terms and conditions as the existing PPAs and/or on more favorable terms and conditions.
- PPA 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 modification.
- Renegotiations of PPAs in anticipation of their expiration, approved by the PUC.

Maui Firm Capacity RFP

The determination of MECO's adequacy of supply is made by applying its capacity planning criteria. In essence, MECO must have a sufficient amount of firm capacity to serve expected peak demand, even with units unavailable due to planned maintenance and with an unexpected outage of the largest generating unit.[104] MECO also gives consideration to maintaining a reserve margin of 20% or greater. MECO's planning criteria are explained more fully in its January 2013 AOS letter. The key inputs to the capacity planning criteria are the expected peak demand, amount of firm capacity on the system, the amount of firm capacity not available due to planned maintenance, and the firm capacity rating of the largest unit on the system.

[104] This criterion is generally referred to as Rule 1.

MECO's most recent Adequacy of Supply letter was filed with the Commission on January 30, 2013 (January 2013 AOS letter). Based on its June 2012 peak forecast[105], its total firm capacity of 262.3 MW-net, and a reduction in firm capacity by 16 MW at the end of 2014 assuming HC&S no longer provides capacity and energy to MECO, MECO concluded that it expects to have an adequate amount of firm capacity for Maui to meet all reasonably expected demands for service and provide reasonable reserves for emergencies for the period 2012 to 2018. MECO also anticipated needing additional firm capacity in the 2019 time frame.

Kahului units K1 and K2 provide a total of 11.4 MW-net of firm capacity. If these units are deactivated or decommissioned in 2013 or 2014 and their capacity is not counted in determining MECO's adequacy of supply, then MECO may have a shortfall of reserve capacity beginning in 2015 if HC&S ceases to provide 16 MW of firm capacity at the end of 2014. If HC&S and K1 and K2 are all unavailable in 2015, MECO estimates it will have a reserve capacity shortfall of about 9 MW based on the assumptions used in its January 2013 AOS letter. The extent to which the capacity from K1 and K2 would be needed will depend on more current projections of peak demand and the amount of capacity that can be contributed by other measures, such as implementing demand response, adding a battery energy storage system and assigning some amount of capacity value to the wind farms, as discussed in the RFP section of this action plan.

MECO is committed to retiring all of the generating units at Kahului Power Plant (KPP) as expeditiously as possible. Retiring the generating units would allow MECO to integrate more renewable energy and reduce consumption of fossil fuel, potentially avoid the cost to address increasingly stricter environmental regulations, and mitigate the risk of having Company-owned generation in a tsunami inundation zone. KPP provides voltage support for the Kahului area. Before KPP can be retired, an alternative means for providing voltage support must be provided. MECO plans to upgrade the Waiinu-Kanaha transmission line to provide that alternative means for voltage support.

In planning and implementing the retirement of KPP, MECO will have to address (in addition to providing an alternative means for providing voltage support in the Kahului area) the adequacy of supply issues resulting from the loss of 36 MW of firm capacity. In its planning for the retirement of KPP, MECO is considering several alternatives, including demand response, energy storage, assigning capacity value to intermittent renewable resources, and/or replacement of old, less efficient generation units with new, quick-starting units.

MECO and HC&S have been in discussion to possibly modify the existing PPA and/or extend the term of the PPA. Any agreement of this nature would need to be favorable for the MECO customers and be in accordance with the CB Framework.

[105] MECO's June 2012 peak forecast projected gradually increasing peak demand ranging from 192.3 MW-net in 2013 to 204.9 MW-net in 2019.

On May 10, 2013, MECO filed an Application in Docket No. 2013-0114 with the PUC for approval of a waiver from the CB Framework, to negotiate with Anaergia Services for 4.5 to 6.0 MW of firm, dispatchable, biogas energy generation.

In addition, MECO will determine the extent to which as-available wind generation can provide equivalent firm capacity to the system. MECO also plans to pursue demand response programs to help offset some of the need for additional firm capacity.

MECO will be willing to acquire additional more efficient and more flexible, replacement generation for economic reasons (that is, to reduce the cost of generating electricity from dispatchable generation on Maui) and deactivating more MECO units. That is more likely to be the case If LNG is available, which is estimated to be in 2020.

Based on the foregoing, MECO plans to issue an RFP for up to 50 MW of firm, dispatchable generation in 2014 allowing time to post the draft, hold a technical conference and issue the proposed final RFP. The firm capacity to be acquired under the RFP will need to be in service before KPP can be deactivated or decommissioned. The amount of capacity that may actually be acquired via the RFP will depend on the cost of the new generation, fuel (if LNG is available), need for additional firm capacity (depending on HC&S availability, KPP deactivation, and Anaergia Services in-service date), system load demand and ancillary services requirements to further integrate as-available variable generation resources. The RFP would specify that new generation have multi-fuel capability for biodiesel, diesel, and LNG.

MECO plans to further evaluate its need for firm capacity and the timing and size of an RFP for firm capacity in its next Adequacy of Supply filing.

The attributes of the generation would include attributes such as, but not limited to:

- Each Generator must be fully dispatchable between its minimum and maximum range by MECO;
- Each Generator must be able to cycle on and off multiple times per day;
- The size of any one Generator shall not exceed 15 MW at unity power factor;
- Each Generator must be able to help regulate (via Automatic Generator Control) and stabilize (via droop) the system frequency. The unit should be capable of setting and operating with a 4% droop characteristic;
- Each Generator must be able to help regulate voltage;
- Each Generator must be able to deliver reactive power at output levels within, and up to the limit of the reactive capability curves of each generator while delivering rated (MW) output. The generator capability (MVA rating) should range from 0.85 lagging to 0.90 leading power factor;

- Each Generator must be able to increase or decrease its power output at a rate equal to or greater than 5 MW per minute;
- The input energy (such as the fuel supply) to the Generator must be renewable and sustainable under the RPS;
- Each Generator able to operate on multiple fuel types to switch when the lowest priced fuel type changes.
- Each Generator must use commercially available and proven technology;
- Generators with black start capability must have the capability to operate in either isochronous or governor droop modes with the ability to transition from one mode to the other on the fly;
- New capacity shall be able to start up and run up to full load within 30 minutes or less from the time a start-up signal is received. In addition, 10 MW of the first 30 MW block will be reserved for 5-minute quick-starting capacity. This 10 MW of new capacity is the output that can be provided within 5 minutes (that is, the time between the start signal and synchronizing the generator to the system, closing the breaker and reaching 10 MW load shall be 5 minutes or less). Quick-start units, after having attained minimum load, must be immediately available to be ramped up to full load operation and meet all environmental requirements for operation up to full load. For any generation resource(s) less than 10 MW (at unity power factor), the new capacity will be required to provide full output within 5 minutes. For resources greater than 10 MW (at unity power factor), the new capacity will be required to provide 10 MW within 5 minutes from the time the start-up signal is received, with the remaining capacity beyond 10 MW to be provided within 30 minutes or less from the time a start-up signal is received;
- The capacity to be provided may come from multiple Generators; and
- Facility scheduled maintenance outage to result in no more than 15 MW of unavailable capacity.

Future RFPs

Connecting the Grids

Implementation Studies

The HCEI Agreement contemplated that implementation studies will be conducted order to systematically assess links between all the islands served by the Hawaiian Electric Companies and to analyze the impacts of the Big Wind Projects and other renewable energy resources on individual island systems affected by them. The studies (Big Wind Implementation Studies) were divided into three stages.

- *Stage 1:* Linking all aspects of the Hawaiian Electric System with only the proposed Molokai wind farm and the Proposed Lanai Wind Farm via an undersea cable system.
- *Stage 2:* Linking the Maui electrical infrastructure to the Hawaiian Electric System to assess the ability of the inter-tied island grids to incorporate and reliably manage additional amounts of diverse renewable generation across the islands and operate the combined generation fleet more efficiently.
- *Stage 3:* Linking all aspects of the Hawaii Island (the Big Island) electrical infrastructure to the inter-tied Oahu/Maui configuration as described in Stage 2 to assess the ability of the inter-tied island grids to incorporate and reliably manage additional amounts of diverse renewable generation across the islands in the Hawaiian Electric Companies' service territories and operate the combined generation fleet more efficiently.

The Stage 1 studies,[106] which were completed in 2011, were structured to facilitate the implementation of the Big Wind Projects, and were intended to identify Big Wind Project integration and performance requirements, undersea cable system requirements, and Hawaiian Electric System modifications, infrastructure additions and operating solutions.

An Oahu Solar Integration Study (OSIS)[107] was initiated in March 2011 and analyzed the system level impacts of high penetrations of central station PV and distributed PV. The OSIS report was completed in April 2013.

The study confirmed that the generation modifications recommended in the Stage 1 studies would also be applicable to high penetration PV scenarios, and with these modifications, the system would be able to accommodate the high penetration scenarios that were studied. It also showed that large Central station PV systems would require significantly more operating

[106] See Chapter 8.

[107] See Chapter 8.

reserves than would large wind plants that could supply the same amount of energy. Gaining frequency responsive PV and wind generation as well as load was also noted as being important to the integration of large scale wind and solar resources.

The Stage 2 study[108] was initiated in March of 2012. The Stage 2 study report was completed in May 2013. The primary objectives of the scenario modeling analyses included in the study were to assess the feasibility and quantify the *value proposition* of interconnecting: (1) MECO's Maui, Lanai and Molokai grids and operating them as one combined system, and (2) the Oahu, Maui, Lanai and Molokai grids and operating them as one combined system — taking into account several possible future scenarios consisting of different mixes of renewable generation and inter-tie configurations. The intent was to have the value of the interconnection benefits identified and rely on the bids in the 200 MW RFP discussed above to provide the cost against which the value could be compared. The study, however, did incorporate available interconnection cost estimates to provide an indication of the cost benefit trade-offs for the different scenarios that were analyzed.

The Stage 2 study results confirmed that the recommendations made in the Stage 1 studies and the OSIS would also be applicable in the interconnection scenarios that were studied. In addition, the study also showed that:

- Interconnection can offer a variety of benefits. It enables sharing of reserves and more efficient operation of the existing thermal fleets. In addition, it positions the system to accept more renewable generation and access to better sites for wind and geothermal generation.
- Scenarios with three AC cables and two DC cables are less economically favorable than the scenarios with single cables due to the increased capital costs associated with the additional cables and the increased level of curtailment.
- Undersea DC cables should be a system asset, not tied to any single renewable asset. This improves overall grid efficiency and available capacity on the cables can be used for additional future renewable energy sources. The nominal 200 MW rating of the cables was not found to be limiting in most cases, even with additional renewable sources.

The question of whether interconnecting the grids on different islands would be cost-effective depends on a number of variables, with the largest variable being the cost of the cable system and the on-island infrastructure. There are also a technical feasibility issues with respect with respect to an undersea cable system extending to the Big Island.

Some high-level economic analyses of connecting generation on other islands to the Oahu grid, and connecting the Oahu and Maui grids were conducted as part of the IRP process, and the results are summarized in Chapter 11. The cost of the cable system will be a fixed cost, regardless of the amount of

[108] See *Chapter 8: Resource Planning and Analysis.*

energy transmitted using the cable system. The estimated capital cost of connecting the Oahu and Maui grids via a direct undersea cable link used in the analyses was about $765 million, which translates to an annual cost of about $99,000,000 per year (including O&M).

The IRP analysis found that only in certain cases would the interconnection between Oahu and Maui result in lower total resource costs. In Case 1, with LNG available on Oahu, there is a small net transfer of energy from Maui to Oahu that is not able to overcome the cost of the interconnection but results in a lower total resource cost. Because of the way the interconnection was modeled, the capital cost of the cable is not captured in the total resource cost directly. Instead the cost of interconnection was modeled as an interconnection charge that was assessed when energy is transferred. In Case 2, with Hawaiian Electric units switched to low sulfur diesel fuel (LSDF) in 2022 to comply with NAAQS regulations, Kahe 1-4 set to cycle, the 208 MW retired with appropriate replacement generation added for reliability, and further wind resources developed in the same year as the cable installation, a large transfer of energy from Maui to Oahu overcomes the cost of interconnection and lowers the total resource costs of the plan. This is true with and without Lanai Wind in service.

The high-level economic analyses summarized in Chapter 11 also looked at the potential economics of connecting the Oahu and Hawaii grids, assuming the technical feasibility of such an undersea cable project. The estimated capital cost of connecting the Oahu and Hawaii grids via a direct undersea cable link used in the high-level analyses was about $2.004 billion, which translates to an annual cost of about $263,000,000 per year (including O&M).

The IRP analysis found that because of the cable costs, only under certain cases would interconnection result in lower total resource costs. If the Hawaiian Electric units were switched to low sulfur diesel fuel in 2022 to comply with NAAQS regulations, Kahe 1 through 4 were cycled, the 208 MW of capacity was retired, and all HELCO units (except for Keahole Combined Cycle) were deactivated and replaced with geothermal resources, then over the study period, the present value of the total resource cost of generation with the interconnection would be lower by about 5%.

Grid Connection RFP

An Undersea Cable System connecting the Oahu and Maui grids could be acquired as a result of the pending RFP for Renewable Energy and Undersea Cable Projects Delivered to the Island of Oahu, discussed above, or as a result of a separate RFP.

The evaluation of Undersea Cable System Bids and Combined Resource Bids submitted in response to the pending RFP will take into account, to the extent practical, the benefits of interconnecting the Oahu and Maui or Maui County grids. In order to facilitate consideration, Undersea Cable System bidders are requested to provide information regarding the incorporation of their proposed Undersea Cable System projects into a cable system connecting the Oahu, Maui, and Hawaii County grids.

It is possible that Undersea Cable System bidders will be requested to supplement their bids to include options that account for various scenarios of additional inter-island connections depending on location of Off-Oahu projects that are proposed.

From a commercial standpoint, there are provisions in the proposed agreements with a cable project developer pursuant to which (1) the initial Undersea Cable System installed pursuant to this RFP may be (a) extended to other islands, or (b) integrated into a network connecting all or some of the grids served by the Hawaiian Electric Companies, (2) the capacity of the initial Undersea Cable System installed pursuant to this RFP may be expanded, and (3) certain technical specifications or performance standards applicable to the Undersea Cable System may be revised. These provisions can be utilized if the result is commercially reasonable from the standpoint of the cable owner and its financing parties.

Given the potential benefits of connecting the Oahu, Maui, and Hawaii County grids, and to adequately address the scope of work that is beyond the realm of the pending RFP, Hawaiian Electric, Hawaii Electric Light Company, and Maui Electric may issue a subsequent RFP. The issuance of such an RFP, and the timing and scope of such an RFP, are subject to approval of the PUC, and would depend on supportive information arising from additional technical, regulatory, and economic analyses.

Small Generation and Customer-Sited Generation Programs

Net Energy Metering

Hawaii's net energy metering (NEM) law requires that electric utilities offer net energy metering to eligible customer generators (that is, a customer generator may be a net user or supplier of energy and will make payment to or receive credit from the electric utility accordingly). The Companies' NEM programs are implemented pursuant to HRS §§269-101-111, Commission orders issued in Docket Nos. 05-0037 (Consolidated) and 2006-0084, and Rule 18 in each Company's respective Commission-approved tariff.

As originally enacted in 2001, the NEM law set limits on the size of NEM systems, and potential limits on the penetration of NEM systems. The law was amended in 2005 and 2008 to authorize the Commission, by rule or order, to increase the maximum size of the eligible net metered systems, to increase the total rated generating capacity available for net energy metering, and to evaluate on an island-by-island basis whether to exempt an island or utility grid system from the total rated generating capacity limits available for net energy metering.

NEM provides for full retail credit for an enrolled customer's excess energy exported to the grid; it is not a power purchase agreement mechanism. This credit is used to offset the customer's electric usage. For billing purposes, a 3-

register net meter is installed at a residential NEM customer's premises to record electric energy delivered from the utility to the premises, energy received from premises, and net energy (the difference between delivered and received energy). Excess net energy recorded during a billing period can be carried over to the next month to further offset usage within that subsequent month. On the anniversary of the customer's start date, a 12-month reconciliation is performed. At the time of reconciliation, if unused credits are available, the lesser of the remaining unused credits or the remaining energy charges eligible for refund will be applied as a refund to the customer's account. However, any remaining unused credits after this reconciliation are forfeited.

NEM has become a very popular program for customers, driven by the full retail credit mechanism, generous state and federal tax credits, declining system costs and a competitive market for rooftop solar photovoltaic (PV) system sales. As a result, growth in NEM customer enrollment has more than doubled year over year for the past 3 years. For Hawaiian Electric, typical PV system size is currently around 6 kilowatts.

As of March 31, 2013, there were 105 MW, 24 MW, and 27 MW of installed NEM capacity from renewable energy technologies (mainly PV) at Hawaiian Electric, HELCO and MECO, respectively. The amount of NEM capacity installed in the first quarter of 2013 was more than twice the amount installed in the same quarter of 2012.

Feed-In Tariff

A Feed-In Tariff (FIT) program encourages the development of renewable energy projects by establishing standard rates and contract terms for selling renewable energy to the utility. Pre-approved contracts and published energy payment rates simplify the contracting process and provide developers with greater certainty to secure financing. Implementing a FIT program was one of the goals of the Hawaii Clean Energy Initiative. In the HCEI Agreement, the Hawaiian Electric Companies committed "to implement feed-in tariffs to dramatically accelerate the addition of renewable energy from new sources" and "to encourage increased development of alternative energy projects."

The Commission initiated an investigation on October 24, 2008 in Docket No. 2008-0273 to examine the implementation of FITs in the Hawaiian Electric Companies' service territories. In a Decision and Order issued on September 25, 2009, the Commission set forth general principles for the implementation of FITs in the Companies' service territories. For the initial FIT, the Commission determined that there would be rates for PV, concentrated solar power (CSP), onshore wind, and in-line hydropower projects up to 5 MW depending on technology and location, as well as a "baseline" FIT rate to encourage other renewable energy technologies. The FIT rates, which were set later in the docket, would be based on the project cost and reasonable profit of a typical project, would be differentiated by technology or resource, size, and interconnection costs; and would be levelized. The Commission also determined that the FIT program will be reexamined two years after it first becomes effective and every three years thereafter. The Commission directed that the "periodic reexamination may focus on updating tariff pricing, applicable technologies, project sizes, and any other matters relevant to the FIT, including queuing and interconnection procedures, curtailment compensation, and non-rate terms and conditions."

Hawaiian Electric launched its FIT program on November 17, 2010 when the Tiers 1 and 2 queues opened for Hawaiian Electric. A week later on November 24, 2010 MECO and HELCO began accepting applications for Tiers 1 and 2.[109] On December 30, 2011 Tier 3 was implemented for all three companies.[110]

The Hawaiian Electric FIT program encompasses four renewable technologies: photovoltaic (PV), concentrated solar power (CSP), onshore wind and in-line hydro. Other RPS-eligible technologies (except biofuel and hybrid projects) are eligible to receive the "baseline" FIT rate.

FIT energy payment rates are differentiated by the type of technology and the size of the project. Tier 1 includes projects up to and including 20 kW. Tier 2 project are larger than 20 kW up to 500 kW depending on technology and location. Tier 3 projects are greater than Tier 2 up to 5 MW, again depending on technology and location. The table below summarizes the tier sizes for each technology and island.

Table 18-1. FIT Tier Sizes and Technologies

Tier	PV	CSP	Wind	Hydro
1	0–20 kW on all islands			
2	500 kW on Oahu 250 kW Maui, Hawaii 100 kW Lanai, Molokai	500 kW on Oahu, Maui, Hawaii 100 kW Lanai, Molokai	100 kW on all islands	
3	5 MW on Oahu 1.9 MW Maui, Hawaii	5 MW on Oahu 1.9 MW Maui, Hawaii	5 MW on Oahu Not available on Maui, Hawaii	Not available
Other RPS-eligible technologies (except biofuel and hybrid projects) can receive the "baseline" FIT rate.				

FIT rates are based on the project cost and reasonable profit of a typical project.[111] Tax credits affect the project development costs, accordingly the solar technologies (PV and CSP) have rates based on the tax credit selected.

[109] On October 13, 2010, the PUC issued its Order Approving FIT Tiers 1 and 2 Tariffs, Standard Agreement, and Queuing and Interconnection Procedures. On November 22, 2011 the Commission issued its Order Approving, with Modifications, HECO Companies' FIT Tier 3 Tariff, Standard Agreement and Queuing and Interconnection Procedures.

[110] On December 29, 2011, the Commission issued Order No. 30074 Approving FIT Program Tariffs, Agreement, Queuing and Interconnection Procedures, filed on December 6, 2011.

[111] Docket 2008-0273, September 25, 2009 D&O on General Principles, page 2.

Table 18-2. FIT Energy Payment Rates (Dollars per Megawatt Hour)

	Tier 1 35%	Tier 1 24.5%*	Tier 2 35%	Tier 2 24.5%*	Tier 3 35%	Tier 3 24.5%*
PV	218	274	189	238	197	236
CSP	269	331	254	275	315	335
Wind	161	n/a	138	n/a	120	n/a
Hydro	213	n/a	189	n/a	–	–
Baseline	120					

* Hawaii Revised Statutes Section 235-12.5 provides the Hawaii state renewable energy technologies income tax credit of 35%. Under HRS Section 235-12.5(g), the Seller may elect a reduced refundable tax credit (effective rate 24.5%) for solar technologies.

The FIT program is capped at 60 MW for Hawaiian Electric, 10 MW for HELCO and 10 MW for MECO. The caps are based on the nameplate capacity equal to 5% of 2008 peak demand for each company.[112] Five percent of the FIT cap is reserved for projects under 20 kW (Tier 1).

At this time Tiers 2 and 3 are oversubscribed for all of the Hawaiian Electric Companies with capacity available only in Tier 1. New FIT applications in Tiers 2 and 3 are placed in a reserve queue. As of May 31, 2013 there are 101 FIT projects totaling 12 MW that have been placed in service. There are 138 applications in the active queue representing an additional 61 MW under development.

Hawaiian Electric filed its reexamination report of Tiers 1 and 2 of the FIT program on March 4, 2013. The report provides the Companies' observations regarding Tiers 1 and 2, general proposals for constructive modifications to the program based on lessons learned, and recommendations for a process to address these proposals.[113]

At this time, the Hawaiian Electric Companies are awaiting further guidance from the Commission on how to proceed with the two-year update.

Rule 14H

Standard interconnection agreements for non-exporting, customer-sited, distributed generators are implemented pursuant to the Tariff Rule No. 14H, approved in Docket Nos. 02-0051, 2006-0497 and 2010-0015. Standard Interconnection Agreements (SIA) are available and required for both renewable and non-renewable systems. The agreement allows a customer to reduce the amount of energy it requires from the utility by energy produced from its own system.

[112] *Ibid.*, page 57.

[113] Docket 2008-0273, Reexamination Report filed March 4, 2013, page 2.

As of May 31, 2013, 76 SIA projects have been executed on Oahu totaling 21.2 MW, 20 SIA projects have been executed on the island of Hawaii, totaling 4.1MW, and 17 SIA projects have been executed on Maui, totaling 4.4 MW.

Schedule Q

The Public Utilities Regulatory Policies Act of 1978, as amended (PURPA the Federal Energy Regulatory Commission (FERC) rules implementing PURPA, and the PUC rules based on the FERC rules (see HAR § 6-74-22(b)), and the PUC-approved tariffs of the Hawaiian Electric Companies, all require that the utilities offer Schedule Q contracts with standard rates to Qualifying Facilities that are small enough (that is, 100 KW or less) to qualify for Schedule Q.

HELCO has four Schedule Q projects totaling 172 kW of capacity. The energy payment rates under Schedule Q, by rule and implementing tariff, are based on the avoided energy cost rates that are currently filed on a quarterly basis under Hawaii Administrative Rules (HAR) § 6-74-17. The filed avoided energy cost rates vary monthly with changes in the cost of fuel oil, since the energy avoided by the facilities that are paid for on the basis of filed avoided energy cost rates is primarily produced from oil-fired generating units.

On April 18, 2008 the Commission opened docket No. 2008-0069 to investigate the appropriate methodology for calculating Schedule Q payment rates. The Hawaiian Electric Companies' position is that the methodology used to set the rates for Schedule Q should be based on (or at least be consistent with) short-run avoided energy costs to meet the requirements of PURPA, but should be fixed and "de-linked" from oil prices to be consistent with HRS § 269-27.2(c). The Commission has granted the parties an extension of time to July 19, 2013 for the parties to file Stipulations.

Ownership of Generation

For the purposes of integrated resource planning, the supply-side resources were evaluated without regard to ownership. The Hawaiian Electric Companies evaluated supply-side technologies that could be implemented by either the utility or independent power producers (IPPs). The resource plans, while characterized using the utility's cost estimates and financing structures, identifies the size and timing of resources without distinction as to the ownership or the resources. IPPs are able to submit proposals to Hawaiian Electric for evaluation to implement, replace, or defer the resource options included in Hawaiian Electric's IRP.

The Commission has previously stated "The IRP framework does not specifically address the role of IPPs in the development or acquisition of the resources deemed appropriate in the IRP. However, the framework, at Section IV.D.2 provides that the utility, in the development of its integrated resource plan, shall consider supply-side and demand-side resource options that 'are or may be supplied by persons other than the utility.' This provision was deliberately intended to leave to the implementation phase the determination of who should build and operate the resource included in the

IRP. IPP-supplied resources should be in conformance with the utility's IRP."[114]

The actual ownership of a resource would be determined later, during the project development phase, if the candidate resource is selected for implementation.

The Competitive Bidding Framework recognizes the importance of utility-owned options, given the utility's obligation to serve. Where the electric utility is addressing a need for firm capacity in order to address system reliability issues or concerns, the Framework requires that:[115]

- In general, the utility shall develop a project proposal that is responsive to the resource need identified in the RFP. The proposal shall represent the utility's best ("self-build" or "utility-owned") response to that need in terms of foreseeable costs and other project characteristics.
- If the utility opts not to advance its own project (that is, over those of other developers), the utility shall request and obtain the Commission's approval.

If the RFP process results in the selection of non-utility (or third-party) projects to meet a system reliability need or statutory requirement, the utility is required to develop and periodically update a Contingency Plan[116] and, if necessary, a Parallel Plan[117] to address the risk that the third-party projects may be delayed or not completed. The utility also may require bidders (subject to the PUC's approval with other elements of a proposed RFP) to offer the utility the option to purchase the project under certain conditions or in the event of default by the seller (that is, the bidder), subject to commercially reasonable payment terms.[118]

Where the RFP process has as its focus something other than a reliability-based need, the utility may choose (or decline) to advance its own project proposal either in the form of a self-build or utility-owned project.[119]

The California PUC (CPUC) also has recognized the importance of utility-owned options where the focus of a procurement process is something other than a reliability-based need. The CPUC does not require investor owned utilities (IOUs) to build RPS resources in order to meet RPS Program goals, but does expect IOUs to consider the option. In Decision 08-02-008 (opinion

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[114] Regarding Integrated Resource Planning, Hawaii Public Utilities Commission, Docket No. 7257, Decision and Order No. 13839, filed March 31, 1995, p. 15.

[115] Framework, Part V.A.

[116] "Contingency Plan" means an electric utility's plan to provide either temporary or permanent generation or load reduction programs to address a near-term need for capacity as a result of an actual or expected failure of an RFP process to produce a viable project proposal, or of a project selected in an RFP. The utility's Contingency Plan may be different from the utility's Parallel Plan and the utility's bid. See Framework, Definitions; Framework, Part II.D.4.

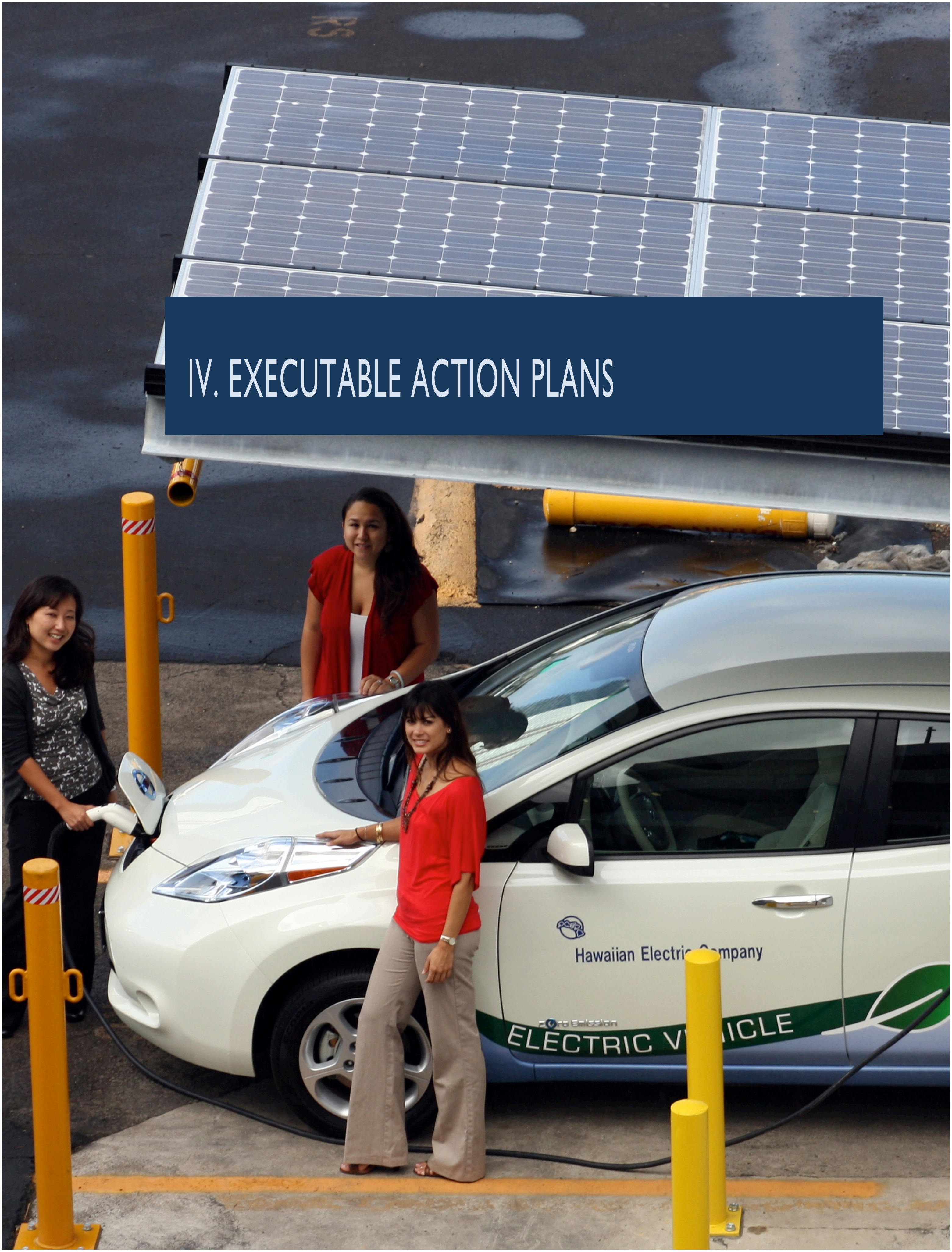
[117] "Parallel Plan" means the generating unit plan (comprised of one or multiple generation resources) that is pursued by the electric utility in parallel with a third-party project selected in an RFP until there is reasonable assurance that the third-party project will reach commercial operation, or until such action can no longer be justified to be reasonable. See Framework, Definitions; Framework, Part II.D.2.

[118] Framework, Part II.D.3.

[119] Framework, Part V.B.

conditionally accepting procurement plans for 2008 RPS solicitations) (D08-02-008), issued February 14, 2008 in Rulemaking 06-05-027, the CPUC noted that "there may be a unique and important role for utility-owned RPS generation. Utility-owned generation from renewable energy resources, for example, can put downward pressure on what are otherwise increasing renewable energy prices. This satisfies an important policy objective that justifies strong consideration of utility ownership." D08-02-008, pages 33–34.

IV. EXECUTABLE ACTION PLANS



Chapter 19: Action Plans

The Companies have created an Action Plan for each utility — Hawaiian Electric Company, Maui Electric Company (with specific actions for Maui, Lanai, and Molokai as appropriate), and Hawaii Electric Light Company — each of which is well-founded and ready to be implemented.

Our Action Plans contain specific actions, resource options, and programs coupled with implementation plans that covers the first five years of our twenty year study period.

Introduction

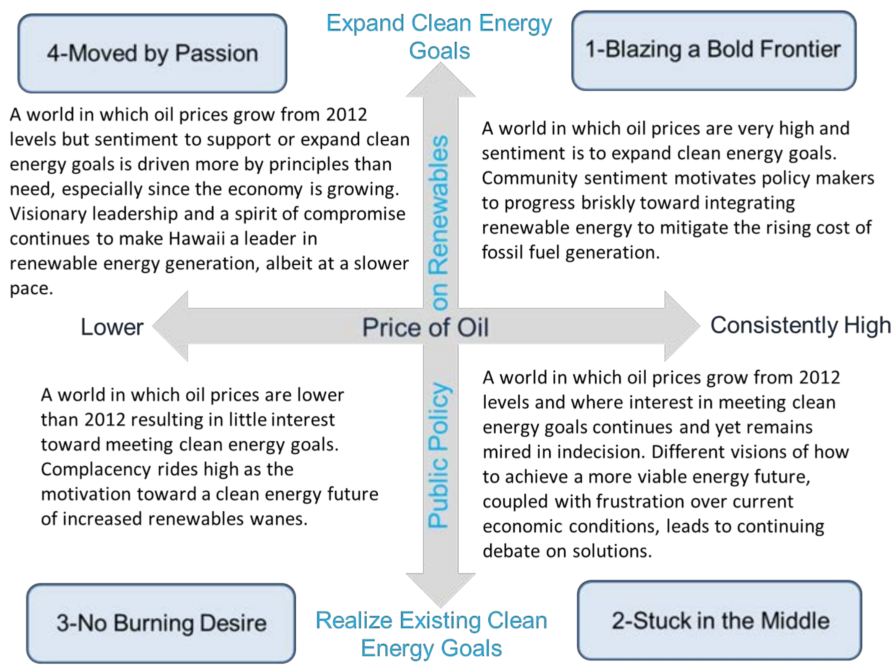
The Companies are committed to meeting our customers' energy needs consistent with State policies and goals. Toward that end, the Companies are aggressively pursuing technologies and policies that responds to customers preferences, increases the use of renewable energy, enhances the efficiency and flexibility of its firm generation, and modernizes the transmission and distribution (T&D) system. This is to be accomplished without compromising service reliability and with a commitment to lower the cost of electricity.

The Companies have created three detailed Action Plans, one for each utility. Each Action Plan represents a reasonable course of action that:

- Meets State energy policies and goals,
- Meets the IRP planning objectives.
- Serves the current and future energy needs of our customers.
- Increases generation from renewable energy sources.
- Provides the greatest value with reasonable costs.
- Is dynamic while remaining flexible enough to adapt to changes in planning assumptions, forecasts, and circumstances.
- Increases safety and reliability.

The Companies have created four scenarios that describe four different possible future outcomes. Our analysis, conducted against these four scenarios, provided the Companies with a wide array of options, and enabled the Companies to better identify and clarify executable actions to meet our current and future energy needs. Basing our analysis on these scenarios has also enabled our Action Plans to remain flexible regarding the dynamic and robust future in which the energy industry operates.

Figure 19-1. Scenario Matrix



Resource Plans and Action Plans

The Companies have developed Action Plans from the substantial amount of information that resulted from the Resource Plans analyzed for the four Scenarios. The Companies examined the numerous analyses to determine what actions demonstrated robust value to balance costs and risks, and provided the most flexibility across the Scenarios and Resource Plans. As stated in the IRP Framework, "The proposed Action Plan may not be the least expensive plan and may include resource options and contingency measures to reasonably address the uncertain future circumstances identified in the various planning Scenarios."[120]

After assessing the various Scenarios and Resource Plans, for each company, the four specific Resource Plans which formed the basis of the Action Plans were defined and labeled as follows:

- Preferred
- Parallel
- Contingency
- Secondary

It should be noted, however, that the "Preferred" Resource Plan in this IRP should not be interpreted in the same way as "Preferred" Resource Plans were interpreted in prior IRPs produced by the Companies. In the previous IRPs, the Action Plan was specifically designed to execute the Preferred

[120] IRP Framework, Section V.C.10.c, page 21.

Resource Plan. In this IRP, the Action Plan is specifically designed to execute actions that would support a range of circumstances that may be defined by the combination of the four Resource Plans.

The IRP analyses addressed two periods:

Planning Period: The 20-year period of 2014–2033 where all feasible combinations of resources were analyzed.

Study Period: The 50-year study period covering the planning period and a 30-year end effects period to analyze the differences between alternatives beyond the planning period's horizon.

Considerations for the Hawaiian Electric Resource and Action Plans

Based on the analysis described in previous chapters and related studies, a review of the resource plans defined actions that demonstrated value and provided flexibility across the evaluated Scenarios. The Action Plan was not developed by solely selecting the "least cost" resource plan produced by the model since each Scenario produced a different "least cost" plan. Instead, the Action Plan contains many of the elements of the resource plans from all the Scenarios that were found to balance costs and risks, and provide other benefits. Relevant considerations are discussed in more detail in the following subsections of this report.

Demand Response

As discussed in *Chapter 8: Resource Planning and Analysis*, implementing the expanded Demand Response (DR) programs provided more capacity deferral benefits than continuing with the existing Demand Response programs, especially in futures where load increases. Including the expanded DR programs in the Action Plan also increases the regulating capability of the system to respond to the increasing amount of variable renewable resources being added each year in any scenario. Properly implemented DR programs also could provide ancillary service benefits by contributing to the regulating reserve that is required to be carried on the system. Conversely, effective use of DR for system operation would result in less use of quick-starting generating resources, with corresponding fuel cost savings.

Decommissioning Units

Based on the modeling analysis discussed in Chapter 8, loss of capacity by the decommissioning of units can trigger the need for additional generation depends upon the future peak load. Review of the firm timing plans reveals that replacement generation from the loss of approximately 100 MW (either from the deactivation of Waiau 3 and 4 or Honolulu 8 and 9) does not trigger the need for new generation to be added except when high load growth is forecasted (No Burning Desire).

Given these circumstances, Hawaiian Electric is committed to accelerating deactivation of existing generation as a means of reducing utility costs. There is transmission and distribution work required before Waiau 3 and 4 can be deactivated. The work is already scheduled and the earliest completion would allow Waiau 3 and 4 to be deactivated by the end of 2017. Similarly, deactivation of Honolulu 8 and 9 in 2014, five years earlier than planned, appears feasible and should be included in all of Hawaiian Electric's Resource Plans and Action Plan. Before the deactivation can occur, however, the underground 46 kV cables in the vicinity of the Honolulu Power Plant need to be upgraded. This work is scheduled to be completed in 2014.

Under a future where peak loads decrease (Blazing a Bold Frontier), this action would not trigger the need for new generation and would result in lower long-range costs. Plans P1_2A1NRETIRE-1R2 TIMING EXPDR and P1_2A1XRETIRE-1R6TEXP show that the total resource costs in the planning and study periods are lower when Honolulu 8 and 9 are deactivated in 2014 versus 2019. In a slightly increasing load future such as in the Stuck in the Middle scenario, the total resource cost trends are not the same because the cumulative impact of earlier loss of capacity leads to and earlier need for new generation. This is seen by comparing the P2_2a1NRetire-1r1 and P2_2A1NRETIRE-1R3 TIMING plans. Despite this long term cost result, deactivation of Honolulu in 2014 does reduce O&M costs which can be used to offset other costs.

CIP CT-1 Best Use

As discussed in Chapter 10, the ability to switch CIP CT-1's fuel from biodiesel to LNG and Ultra Low Sulfur Diesel was evaluated for both simple cycle and conversion to combined cycle operation by the addition of a heat recovery steam generator and steam turbine. Based on the analysis, if biodiesel prices are high in the future, a fuel switch to a lower price fuel, such as ULSD or LNG, would be more cost effective. Under a future with lower cost biodiesel, keeping CIP CT-1 on biodiesel is the best option. Converting CIP CT-1 to combined cycle operation results in lower overall plan costs whether using biodiesel, ULSD, or LNG compared to operating in simple cycle mode with the same fuel. Therefore, converting CIP CT-1 to combined cycle provides more efficient use of fuel, whether it's biodiesel, ULSD, or LNG in the future. Accordingly, the Action Plan includes activities to convert the unit to combined cycle, and to modify the combustion equipment and air permit to allow operation on whatever fuel is lowest cost, biodiesel, ULSD, or LNG, with approval of the Commission.

Many of the resource plans in all of the scenarios included the addition of 51 MW biofuel-fired Internal Combustion Engine (ICE) plant in 2017. This resource would be a quick-starting, agile, fuel-efficient, renewable fueled, dispatchable generator located on federal lands at Schofield Barracks (Schofield Generating Station). This type of generator could provide the ancillary services that enables increased deployment of intermittent renewable resources on Oahu. It would also provide energy security for Schofield Barracks and the only black-start capability on Oahu that is not located in a tsunami inundation zone. The Commission granted a waiver from the Framework for Competitive Bidding for this project, subject to certain conditions, in Docket No. 2011-0386. The Company's Action Plan includes activities to support this project.

With the conversion of CIP CT-1 to combined cycle and adding the capability to burn ULSD and/or LNG with approval of the Commission, the biodiesel that would have been consumed at CIP CT-1 could then be used at this Schofield Generating Station. The Schofield Generating Station is designed to operate at a heat rate (that is, fuel efficiency) approximately equivalent to that for CIP CT-1 in a combined cycle mode, and approximately twice as efficient as CIP CT-1 in a simple cycle mode. If the biodiesel originally intended for CIP CT-1 were to be deployed at Schofield Generating Station it would contribute to the Companies' attainment of RPS.

Environmental Compliance

As discussed in *Chapter 9: Environmental Regulation Compliance*, fuel switching strategies result in lower costs than the installation of Air Quality Control equipment on existing generating units to comply with environmental regulations. The availability and cost of the fuel, however, determines what fuel will be used in lieu of LSFO. For compliance with the MATS regulations, 0.5% sulfur diesel is assumed in the resource plans as known compliance fuel available for use in 2016. Compliance with the NAAQS regulations could be accommodated by switching to diesel fuels with less than 0.05% sulfur, biofuels, or LNG by 2022.

If there is a future where technology breakthroughs or market forces such as envisioned in Blazing a Bold Frontier occur, low biofuel costs could result in the lowest rate impact compared to alternatives. If LNG proves to be available in the future, it has the potential to provide the lowest rates compared to the other fuel options as shown in the other three scenarios when used to replace oil in existing units.

If and when the availability of LNG is assured, further evaluation of decommissioning the existing generation and replacing them with new gas-fired combined cycle units would be evaluated through a competitive bidding process to assess whether the cost for new generation could be offset by the improved system efficiency and lower fuel costs. Therefore, the final four Resource Plans and Action Plan contain fuel switching activities for environmental compliance, working towards obtaining LNG in Hawaii, and periodically testing the biofuels market.

Biofuels

Biofuels is an integral part of Hawaiian Electric's renewable energy strategy to actively seek and incorporate a diverse portfolio of new renewable resources. Biofuels, produced from local energy crops, have the following benefits: creates new jobs in Hawaii, retains the billions of dollars that are spent on imported oil in the State, increases Hawaii's energy security, invigorates Hawaii's agriculture industry, supports the State's goal of diversifying Hawaii's economy by encouraging the development of local agriculture, reduces greenhouse gas emissions, and provides a local fuel alternative for marine, land, and aviation transportation. Another important consideration is that biofuels can be used to generate renewable energy for existing conventional generating units which provide essential grid services, including load following, frequency response, voltage control, and on-line operating and spinning reserves. Hawaiian Electric has submitted an application for the approval of a biofuel supply contract with Hawai`i BioEnergy, LLC (HBE) in Docket No. 2011-0369.

The Kahe Power Plant (KPP) provides baseload generation and essential grid management services by maintaining generation in Kapolei, Hawaii. In all the Hawaiian Electric action plans KPP will consume approximately 10 million of gallons of biofuel provided by Hawaii BioEnergy, LLC starting in the 2016–2018 time frame.

Wind and Photovoltaics

Utility-scale wind and PV resources were found to be the most cost competitive resources (when including tax credits) in all four scenarios. This is shown in the resource plans (*Appendix O: Resource Plan Sheets*) where wind and PV resources are found in almost all of the plans when they were allowed to be selected by the model. Wind and PV were cost competitive against other resource options and the cost of operating the existing system based on the assumptions of the various scenarios. The scenario analysis did not account for technical issues associated with the interconnection of additional variable renewable energy, including PV and wind, which may have negative impacts to reliability and circuit penetration. It should also be noted that the IRP analysis did not include detailed grid stability analysis or intra-hour analysis, as these types of studies are for shorter time frames (that is, hours, months, one year) whereas the IRP is conducted over a 20-year time frame. Any technical issues associated with interconnection of additional variable renewable energy will be addressed as discussed in *Chapter 16: Integrating High Penetration of Variable Distributed Generation*.

To determine the true costs of renewable resources included in the Action Plan is conducting a fair and competitive RFP for renewable resources.

The Action Plan will include an RFP that will target adding approximately 700 GWh of variable renewable energy by 2020. These resources are represented by PV and Wind resources in the Preferred Resource Plan but any renewable resource could participate in the competitive bidding processes. Moreover, the RFP would consider on-island and inter-island resources.

Because PV and Wind were found to be cost competitive in the near term, the Company is also including adding by the end of 2015 up to approximately 137 GWH of renewable energy from fast-track low cost PV and Wind projects. These projects will require a waiver from the Hawaii Public Utility Commission Competitive Bidding Framework. The Company will also be developing self-build options renewable energy projects under this same context.

Kalaeloa Power Purchase Agreement

Continuation of the Kalaeloa Power Purchase Agreement (PPA) was assumed in many of the resource plans (shown in *Appendix O: Resource Plan Sheets*). Alternatively, the termination of the PPA was studied in several of the resource plans, and in future scenarios where the load grows it triggers the need for new capacity. Even with the reactivation of Honolulu 8 and 9 and delay of deactivation of Waiau 3 and 4, replacement capacity would need to be installed as early as 2017 in the Stuck in the Middle scenario (see Plans P2_2a1NRetire-1r4, P2_2a1NRetire-1r6, P2_2a1NRetire-1r8, P2_2a1NRetire-1r10, P2_2a1NRetire-1r13, and P2B2b1NRetire-1r14) or not required at all if the Blazing a Bold Frontier future unfolds (see plan P1_2A1XRETIRE-1R7 T4exp).

However, plans with the Kalaeloa PPA ending in 2016 are generally more costly than plans with Kalaeloa continuing because of the need to add the new capacity. However, a major uncertainty is what will be the cost of the PPA to continue operation of the Kalaeloa plant. Thus, the Action Plan includes activities to renegotiate a new PPA with terms that are in the best interest of our customers.

New Capacity

The scenario analysis confirmed the uncertainty the Company faces with respect to the need to plan for and add new capacity in meeting the planning criteria. The analysis shows that the need to add new capacity is influenced by these factors:

- Peak load and its driving factors which are illustrated by the scenarios. The differences in timing between the plans P1_2a1X-1r2, P2_2a1NRetire-1r12, P3_2a1N-1r0, and P4_2a1X-1r0.
- Whether power purchase contracts end or can be extended. See Kalaeloa discussion above.
- Deactivation and decommissioning of existing resources (Honolulu 8 & 9 and Waiau 3 &4). See difference between P1B2a1xRetire-2r3 and P1B2a1xRetire-2r4; P2_2a1NRetire-1r3 and P2B2b1NRetire-4Er0 timing; P3_2a1NRetire-1r0 and P3B2b1NRetire-4Er0; P4_2a1NRetire-1r1 and P4B2b1NRetire-4Er1.
- Deactivation and decommissioning of additional generation such as Waiaus 5 & 6 and/or Kahe 1 & 2.
- Addition of new capacity from conversion of CIP to combined cycle and the Schofield Generating Station.

Therefore, any RFP for new capacity will need to take into account the influence of these factors to determine the timing and size of needed capacity.

Baseload Generation

Based on the analysis discussed in *Chapter 8: Resource Planning and Analysis*, increasing the operational flexibility of baseloaded generation by lowering their minimum load capability (that is, increasing "turndown") and/or converting from baseload operation to cycling operation has system benefits. Therefore, the Action Plan includes activities to increase operational flexibility of existing baseload generating units.

Energy Storage

As discussed in Chapter 8, energy storage can reduce curtailment of renewable energy. Currently HELCO is engaged in various collaborative projects for energy storage. HELCO is working with Hawaii Natural Energy Institute to evaluate a 1MW/250kWh fast-response lithium titanate BESS to smooth the output of the Hawi wind farm. Also, HELCO is evaluating two 100kW/248 kWh lithium ion BESS installed at two customer-owned PV projects in July 2012.

Lanai Wind Project

Energy from the 200 MW Lanai Wind project was analyzed in all of the scenarios. As discussed in *Chapter 11: Inter-Island and Inter-Utility Connection Analysis*, the uncertainty with the interisland cable cost assumptions is a major factor in whether this project is cost competitive and will materialize.

There are also qualitative factors that must also be considered such as:

- Visual Impact: obstruction of view planes and aesthetics,
- Hazards to birds and wildlife.
- Whale habitat: dangers posed by cable laying ships and submerged cable.
- Reef Impact: damage from cable laying and directional drilling.
- EMF impacts on sea life.
- Onshore termination: land impacts, land use, visual impacts for onshore conversion stations.
- Turbine location known to contain culturally sensitive areas.

The Companies recognize that there are many uncertainties that question the viability of completion of this project due to community opposition. However, the Companies have a legally-binding Term Sheet for this project and will continue to consider negotiation of a PPA for this project in the Action Plan.

Hawaiian Electric Resource Plans

As required by the Framework, the Company has developed alternative Resource Plans based on review of the analysis and resource plans (shown in *Appendix O: Resource Plan Sheets*). The four Resource Plans are designated as the Preferred Resource Plan, Contingency Resource Plan, Parallel Resource Plan, and Secondary Resource Plan (see Table 19- and Table 19-3). These plans identify resources and describe generally what the 20-year plans would look like if the future were to unfold as described by the particular scenario. The Company chose to describe the four plans in two Scenarios: Blazing a Bold Frontier and Stuck in the Middle (the “Reference Case”) which represent two divergent futures that could occur. In contrast to prior IRPs produced by the Companies, the Action Plan supports implementation of all four of these plans. In prior IRPs, the Action Plan was specifically correlated to the Preferred Plan.

Quantitative metrics for the four plans are provided in Appendix P for the two scenarios. Qualitative metrics applicable to the resources shown on the plan are described in *Chapter 17: Advisory Group Qualitative Metric Considerations*.

These plans support protection of Hawaii's environment by reducing greenhouse gases, sulfur oxide emissions, oxides of nitrogen, and particulate matter emissions. They reduce the dependency on imported fossil fuels by dramatically increasing the percent of energy generated by renewable resources. The diversity of the portfolio of resources increases which strengthens Hawaii's energy independence by the reduction in dependency on any single type of resource. Operating flexibility of the system improves with increases in system regulating capability.

The plans also identify challenges that lie ahead including operating the system as the variable energy resource penetration on the grid increases to unprecedented levels and the opportunity to improve operating flexibility to mitigate system constraints to decrease or eliminate curtailed renewable energy. The intent is also to minimize the amount of intermittent renewable energy that is otherwise curtailed.

Table 19-1. HECO Preferred and Contingency Resource Plans: Blazing a Bold Frontier

Blazing a Bold Frontier			**Preferred Resource Plan** **LNG Existing Generation**	**Contingency Plan** **No LNG**
Name	**Self Generation**		**P1B2a1NRetire-2r11**	**P1B2a1NRetire-2r12**
Plan	Annual	Cumulative	LNG; KPLP continue; Cycle Kahe 1–4	ULSD; KPLP continue; Cycle Kahe 1–4
Notes			Deactivate Honolulu 8/9 at end of 2014, cycle Kahe 1–4 in 2018	Deactivate Honolulu 8/9 at end of 2014, cycle Kahe 1–4 in 2018
Resources Available			ICE (17 MW)-Biodiesel (PS01): Fixed Convert CT-1 to CC 57MW (STC1): Fixed Battery (15 MWh): Fixed 30 MW Onshore Wind C3 (PW01): 2020 5 MW of 1 MW Track PV (PP03): 2020 200 MW Lanai Wind: n/a	ICE (17 MW)-Biodiesel (PS01): Fixed Convert CT-1 to CC 57MW (STC1): Fixed Battery (15 MWh): Fixed 30 MW Onshore Wind C3 (PW01): 2020 5 MW of 1 MW Track PV (PP03): 2020 200 MW Lanai Wind: n/a
2014	64MW	137MW	Expanded CIDLC, CIDP, RDLCWH, RDLCAC	Expanded CIDLC, CIDP, RDLCWH, RDLCAC
			75%+25%+10% PBFA DSM	75%+25%+10% PBFA DSM
			Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW)	Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW)
2015	66MW	203MW	Add 20 MW wind (PWWRx2)	Add 20 MW wind (PWWRx2)
			Add 40 MW PV (PPWRx8)	Add 40 MW PV (PPWRx8)
2016	79MW	281MW	Fuel switch to diesel (Waiau 5–8/Kahe 1–6)	Fuel switch to diesel (Waiau 5–8/Kahe 1–6)
			Fuel switch to ULSD (CIP-1)	Fuel switch to ULSD (CIP-1)
			Add 20 MW wind (PWWRx2)	Add 20 MW wind (PWWRx2)
			Add 80 MW PV (PPWRx16)	Add 80 MW PV (PPWRx16)
2017	65MW	347MW	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)
			Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)
			Add 51 MW ICE (PS01x3); biofuel	Add 51 MW ICE (PS01x3); biofuel
			Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW)	Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW)
2018	65MW	412MW	Convert CT-1 to CC +57MW (STC1); ULSD	Convert CT-1 to CC +57MW (STC1); ULSD
			Add 15 MWh battery (PB01x1)	Add 15 MWh battery (PB01x1)
			Cycle Kahe 1–4	Cycle Kahe 1–4
			Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)
			Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)
2019	65MW	477MW		Add 60 MW wind (PW01x2)
			Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)
2020	65MW	541MW	Fuel switch to LNG (Waiau 5–8, Kahe 1–6,CIP CC-1, Kalaeloa)	
				Add 60 MW wind (PW01x2)
2021	65MW	606MW		Add 60 MW wind (PW01x2)

Blazing a Bold Frontier			Preferred Resource Plan LNG Existing Generation	Contingency Plan No LNG
Name	**Self Generation**		**P1B2a1NRetire-2r11**	**P1B2a1NRetire-2r12**
2022	60MW	666MW		Fuel switch to ULSD (Waiau 5–10/Kahe 1–6)
2023	51MW	718MW		
2024	45MW	763MW		
2025	39MW	802MW		Add 60 MW wind (PW01x2)
2026	34MW	835MW		Add 60 MW wind (PW01x2)
2027	30MW	865MW		Add 60 MW wind (PW01x2) Add 20 MW PV (PP03x4)
2028	27MW	892MW		Add 60 MW wind (PW01x2) Add 20 MW PV (PP03x4)
2029	25MW	917MW		Add 60 MW wind (PW01x2) Add 20 MW PV (PP03x4)
2030	24MW	941MW		Add 60 MW wind (PW01x2) Add 20 MW PV (PP03x4)
2031	23MW	963MW		Add 60 MW wind (PW01x2) Add 20 MW PV (PP03x4)
2032	22MW	985MW		Add 60 MW wind (PW01x2) Add 20 MW PV (PP03x4)
2033	21MW	1007MW		Add 60 MW wind (PW01x2) Add 20 MW PV (PP03x4)
Strategist Planning Period Total Cost			25,845,808	28,466,722
Strategist Study Period Total Cost			33,343,386	36,562,072
Planning Period Total Cost			27,394,017	29,767,842
Study Period Total Cost			34,891,595	39,538,600
Planning Rank			1	2
Study Rank			1	2

Table 19-2. HECO Parallel and Secondary Resource Plans: Blazing a Bold Frontier

Blazing a Bold Frontier			Parallel Plan With Lanai Wind	Secondary Plan No Kalaeloa with New LNG Generation
Name	**Self Generation**		**P1B2a1NRetire-2r13**	**P1B2a1NRetire-2r14**
Plan	Annual	Cumulative	LNG; KPLP continue; Cycle Kahe 1–4; Lanai Wind	LNG; KPLP continue; Cycle Kahe 1–4; Lanai Wind
Notes			Deactivate Honolulu 8/9 at end of 2014, cycle Kahe 1–4 in 2018	Deactivate Honolulu 8/9 at end of 2014, cycle Kahe 1–4 in 2018
Resources Available			ICE (17 MW)-Biodiesel (PS01): Fixed Convert CT-1 to CC 57MW (STC1): Fixed Battery (15 MWh): Fixed 30 MW Onshore Wind C3 (PW01): 2020 5 MW of 1 MW Track PV (PP03): 2020 200 MW Lanai Wind: n/a	ICE (17 MW)-Biodiesel (PS01): Fixed Convert CT-1 to CC 57MW (STC1): Fixed Battery (15 MWh): Fixed 30 MW Onshore Wind C3 (PW01): 2020 5 MW of 1 MW Track PV (PP03): 2020 200 MW Lanai Wind: n/a
2014	64MW	137MW	Expanded CIDLC, CIDP, RDLCWH, RDLCAC	Expanded CIDLC, CIDP, RDLCWH, RDLCAC
			75%+25%+10% PBFA DSM	75%+25%+10% PBFA DSM
			Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW)	Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW)
2015	66MW	203MW	Add 20 MW wind (PWWRx2)	Add 20 MW wind (PWWRx2)
			Add 40 MW PV (PPWRx8)	Add 40 MW PV (PPWRx8)
2016	79MW	281MW	Fuel switch to diesel (Waiau 5–8/Kahe 1–6)	Fuel switch to diesel (Waiau 5–8/Kahe 1–6)
			Fuel switch to ULSD (CIP-1)	Fuel switch to ULSD (CIP-1)
			Add 20 MW wind (PWWRx2)	Add 20 MW wind (PWWRx2)
			Add 80 MW PV (PPWRx16)	Add 80 MW PV (PPWRx16)
2017	65MW	347MW	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)
			Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)
			Add 51 MW ICE (PS01x3); biofuel	Add 51 MW ICE (PS01x3); biofuel
			Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW)	KPLP contract ends (–208MW)
2018	65MW	412MW	Convert CT-1 to CC +57MW (STC1); ULSD	Convert CT-1 to CC +57MW (STC1); ULSD
			Add 15 MWh battery (PB01x1)	Add 15 MWh battery (PB01x1)
				Fuel switch to Kahe 3 to biocrude blend
			Cycle Kahe 1–4	Cycle Kahe 1–4
			Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)
			Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)
2019	65MW	477MW		Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW)
			Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)
			Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)

Blazing a Bold Frontier			**Parallel Plan With Lanai Wind**	**Secondary Plan No Kalaeloa with New LNG Generation**
Name	**Self Generation**		**P1B2a1NRetire-2r13**	**P1B2a1NRetire-2r14**
2020	65MW	541MW	Fuel switch to LNG (Waiau 5–8, Kahe 1–6,CIP CC-1, Kalaeloa)	Add 285MW SCCT (PS08x3); LNG
				Add 42MW SCCT (PS10x1); LNG
			Add 200MW Lanai Wind	Retire W5 (–55MW) Retire W6 (–56MW) Retire W7 (–88MW) Retire W8 (–88MW) Retire K1 (–88MW) Retire K2 (–86MW) Retire K3 (–88MW) Retire K4 (–89MW)
				Add 60 MW wind (PW01x2)
				Add 20 MW PV (PP03x4)
2021	65MW	606MW		Add 177MW CC (PS12x3); LNG
				Retire K5 (–135MW)
				Add 60 MW wind (PW01x2)
				Add 20 MW PV (PP03x4)
2022	60MW	666MW		Add 95MW SCCT (PS08x1); LNG
				Retire KAHE 6 (–134MW)
				Add 60 MW wind (PW01x2)
				Add 20 MW PV (PP03x4)
2023	51MW	718MW		Add 60 MW wind (PW01x2)
				Add 59MW CC (PS12x1); LNG
2024	45MW	763MW		Add 60 MW wind (PW01x2)
2025	39MW	802MW		Add 60 MW wind (PW01x2)
2026	34MW	835MW		Add 60 MW wind (PW01x2)
2027	30MW	865MW		
2028	27MW	892MW		
2029	25MW	917MW		
2030	24MW	941MW		Add 60 MW wind (PW01x2)
2031	23MW	963MW		Add 60 MW wind (PW01x2)
2032	22MW	985MW		Add 60 MW wind (PW01x2)
2033	21MW	1007MW		Add 60 MW wind (PW01x2)
Strategist Planning Period Total Cost			26,278,714	26,082,882
Strategist Study Period Total Cost			34,077,944	32,193,226
Planning Period Total Cost			27,826,921	25,291,589

Blazing a Bold Frontier			**Parallel Plan** **With Lanai Wind**	**Secondary Plan No Kalaeloa with New LNG Generation**
Name	**Self Generation**		**P1B2a1NRetire-2r13**	**P1B2a1NRetire-2r14**
Study Period Total Cost			35,626,153	33,238,826
Planning Rank			2	1
Study Rank			2	1

Table 19-3. HECO Preferred and Contingency Resource Plans: Stuck in the Middle

Stuck in the Middle			**Preferred Resource Plan LNG Existing Generation**	**Contingency Plan No LNG**
Name	**Self Generation**		**P2B2a1NRetire-2r15**	**P2B2a1NRetire-2r16**
Plan			LNG, 30 MW Wind, 5 MW PV, Cycle Kahe 1–4, Waiver Projects	No LNG, 30 MW Wind, 5 MW PV, Cycle Kahe 1–4, Waiver Projects
Notes			CT-1 Conversion to CC 2018	CT-1 Conversion to CC 2018
Resources Available	Annual	Cumulative	17 MW ICE; Biodiesel (PS01): Fixed 25MW Banagrass Combustion (PA01): 2022 30 MW Onshore Wind Cl 3 (PW01): 2016 Lanai Wind: 2020A 10 MW Onshore Wind Cl 7 (PW04): n/a 100 MW Offshore Wind (PW05): n/a 5 MW of 1 MW Tracking PV (PP03): 2015 50 MW Parbolic Trough PV (PP04): n/a 9.6 MW OTEC (POT1): n/a 15 MW Ocean Wave (PV02): n/a	17 MW ICE; Biodiesel (PS01): Fixed 25MW Banagrass Combustion (PA01): 2022 30 MW Onshore Wind Cl 3 (PW01): 2016 Lanai Wind: 2020A 10 MW Onshore Wind Cl 7 (PW04): n/a 100 MW Offshore Wind (PW05): n/a 5 MW of 1 MW Tracking PV (PP03): 2015 50 MW Parbolic Trough PV (PP04): n/a 9.6 MW OTEC (POT1): n/a 15 MW Ocean Wave (PV02): n/a
2014	35MW	75MW	Expanded CIDLC, CIDP, RDLCWH, RDLCAC	Expanded CIDLC, CIDP, RDLCWH, RDLCAC
			75% PBFA DSM	75% PBFA DSM
			Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW)	Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW)
2015	36MW	111MW	Add 20 MW wind (PWWRx2)	Add 20 MW wind (PWWRx2)
			Add 40 MW PV (PPWRx8)	Add 40 MW PV (PPWRx8)
2016	43MW	154MW	Fuel switch to ULSD (CIP-1)	Fuel switch to ULSD (CIP-1)
			Add 20 MW wind (PWWRx2)	Add 20 MW wind (PWWRx2)
			Add 80 MW PV (PPWRx16)	Add 80 MW PV (PPWRx16)
			Fuel switch to diesel (Waiau 5–8, Kahe 1–6)	Fuel switch to diesel (Waiau 5–8, Kahe 1–6)
2017	36MW	189MW	Add 51MW ICE (PS01x3); biofuel	Add 51MW ICE (PS01x3); biofuel
			Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)
			Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)
			Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW)	Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW)
2018	36MW	225MW	Convert CT-1 to CC +57MW (STC1); ULSD	Convert CT-1 to CC +57MW (STC1); ULSD
			Cycle Kahe 1–4	Cycle Kahe 1–4
			Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)
			Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)
			Add 15 MWh battery (PB01x1)	Add 15 MWh battery (PB01x1)
2019	35MW	260MW	Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)
			Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)
2020	35MW	295MW	Fuel switch to LNG (Waiau 5–8, Kahe 1–6, CIP CC-1, Kalaeloa)	Add 60 MW wind (PW01x2)

Stuck in the Middle			Preferred Resource Plan LNG Existing Generation	Contingency Plan No LNG
Name	**Self Generation**		**P2B2a1NRetire-2r15**	**P2B2a1NRetire-2r16**
2021	35MW	331MW		Add 60 MW wind (PW01x2)
2022	28MW	363MW		Add 60 MW wind (PW01x2) Fuel switch to ULSD (Waiau 5–8, Kahe 1–6)
2023	28MW	391MW		Add 60 MW wind (PW01x2)
2024	25MW	416MW		Add 60 MW wind (PW01x2)
2025	21MW	437MW		Add 60 MW wind (PW01x2)
2026	18MW	456MW	Add 60 MW wind (PW01x2)	
2027	16MW	472MW	Add 60 MW wind (PW01x2)	
2028	15MW	486MW	Add 60 MW wind (PW01x2)	
2029	14MW	500MW	Add 60 MW wind (PW01x2)	
2030	13MW	513MW	Add 60 MW wind (PW01x2)	
2031	12MW	525MW		Add 60 MW wind (PW01x2)
2032	12MW	538MW		Add 60 MW wind (PW01x2)
2033	12MW	549MW		
Planning Period Total Cost			18,729,652	21,314,870
Study Period Total Cost			25,817,764	31,084,122
Planning Period Total Cost			21,709,780	24,295,002
Study Period Total Cost			28,797,892	34,064,250
Planning Rank			1	2
Study Rank			1	2

Table 19-4. HECO Parallel and Secondary Resource Plans: Stuck in the Middle

Stuck in the Middle			**Parallel Plan With Lanai Wind**	**Secondary Plan No Kalaeloa with New LNG Generation**
Name	**Self Generation**		**P2B2a1NRetire-2r17**	**P2B2a1NRetire-2r18**
Plan	Annual	Cumulative	LNG, 30 MW Wind, 5 MW PV, Lanai Wind in 2020 Cycle Kahe 1–4, Waiver Projects	LNG, 30 MW Wind, 5 MW PV, No Kalaeloa Cycle Kahe 1–4, Waiver Projects
Notes			CT-1 Conversion to CC 2018	CT-1 Conversion to CC 2018
Resources Available			17 MW ICE; Biodiesel (PS01): Fixed 25MW Banagrass Combustion (PA01): 2022 30 MW Onshore Wind Cl 3 (PW01): 2016 Lanai Wind: 2020 10 MW Onshore Wind Cl 7 (PW04): n/a 100 MW Offshore Wind (PW05): n/a 5 MW of 1 MW Tracking PV (PP03): 2015 50 MW Parbolic Trough PV (PP04): n/a 9.6 MW OTEC (POT1): n/a 15 MW Ocean Wave (PV02): n/a	17 MW ICE; Biodiesel (PS01): Fixed 25MW Banagrass Combustion (PA01): n/a 30 MW Onshore Wind Cl 3 (PW01): 2016 Lanai Wind: 2020 10 MW Onshore Wind Cl 7 (PW04): n/a 100 MW Offshore Wind (PW05): n/a 5 MW of 1 MW Tracking PV (PP03): 2015 50 MW Parbolic Trough PV (PP04): n/a 9.6 MW OTEC (POT1): n/a 15 MW Ocean Wave (PV02): n/a
2014	35MW	75MW	Expanded CIDLC, CIDP, RDLCWH, RDLCAC	Expanded CIDLC, CIDP, RDLCWH, RDLCAC
			75% PBFA DSM	75% PBFA DSM
			Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW)	Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW)
2015	36MW	111MW	Add 20 MW wind (PWWRx2)	Add 20 MW wind (PWWRx2)
			Add 40 MW PV (PPWRx8)	Add 40 MW PV (PPWRx8)
2016	43MW	154MW	Fuel switch to ULSD (CIP-1)	Fuel switch to ULSD (CIP-1)
			Add 20 MW wind (PWWRx2)	Add 20 MW wind (PWWRx2)
			Add 80 MW PV (PPWRx16)	Add 80 MW PV (PPWRx16)
			Fuel switch to diesel (Waiau 5–8, Kahe 1–6)	Fuel switch to diesel (Waiau 5–8, Kahe 1–6)
2017	36MW	189MW		Activate H8 (+53MW) Activate H9 (+54MW)
				Convert CT-1 to CC +57MW (STC1); ULSD
			Add 51MW ICE (PS01x3); biofuel	Add 51MW ICE (PS01x3); biofuel
			Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)
			Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)
				KPLP contract ends (–208MW)
			Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW)	
2018	36MW	225MW	Convert CT-1 to CC +57MW (STC1); ULSD	Fuel switch to Kahe 3 to biofuel blend
			Cycle Kahe 1–4	Cycle Kahe 1–4
			Add 60 MW wind (PW01x2)	Add 60 MW wind (PW01x2)
			Add 20 MW PV (PP03x4)	Add 20 MW PV (PP03x4)
			Add 15 MWh battery (PB01x1)	Add 15 MWh battery (PB01x1)

Stuck in the Middle			Parallel Plan With Lanai Wind	Secondary Plan No Kalaeloa with New LNG Generation
Name	**Self Generation**		**P2B2a1NRetire-2r17**	**P2B2a1NRetire-2r18**
2019	35MW	260MW		Add 95MW SCCT (PS08x1); biodiesel/LNG
				Add 60 MW wind (PW01x2)
			Add 60 MW wind (PW01x2)	Add 20 MW PV (PP03x4)
			Add 20 MW PV (PP03x4)	Deactivate Waiau 3 (–46 MW) Deactivate Waiau 4 (–46 MW)
				Deactivate Honolulu 8 (–53 MW) Deactivate Honolulu 9 (–54 MW)
2020	35MW	295MW	Fuel switch to LNG (Waiau 5–8, Kahe 1–6, CIP CC-1, Kalaeloa)	Add 285MW SCCT (PS08x3); LNG
				Add 177MW CC (PS12x3); LNG
			Add 200 MW Lanai Wind	Retire W5 (–55MW) Retire W6 (–56MW) Retire W7 (–88MW) Retire W8 (–88MW) Retire K1 (–88MW) Retire K2 (–86MW) Retire K3 (–88MW) Retire K4 (–89MW)
2021	35MW	331MW		Add 177MW CC (PS12x3); LNG
				Retire K5 (–135MW)
2022	28MW	363MW		Add 190MW SCCT (PS08x2); LNG
				Retire KAHE 6 (–134MW)
2023	28MW	391MW		Add 95MW SCCT (PS08x1); LNG
2024	25MW	416MW		
2025	21MW	437MW		
2026	18MW	456MW		
2027	16MW	472MW		
2028	15MW	486MW		
2029	14MW	500MW		Add 60 MW wind (PW01x2)
2030	13MW	513MW	Add 30 MW wind (PW01x1)	Add 60 MW wind (PW01x2)
2031	12MW	525MW		
2032	12MW	538MW		Add 30 MW wind (PW01x1)
2033	12MW	549MW		
Planning Period Total Cost			18,874,302	20,821,548
Study Period Total Cost			25,714,928	28,555,732
Planning Period Total Cost			21,854,431	23,395,202

Stuck in the Middle			**Parallel Plan With Lanai Wind**	**Secondary Plan No Kalaeloa with New LNG Generation**
Name	**Self Generation**		**P2B2a1NRetire-2r17**	**P2B2a1NRetire-2r18**
Study Period Total Cost			28,695,056	31,129,385
Planning Rank			1	2
Study Rank			1	2

Considerations for the HELCO Resource and Action Plans

Similar to Hawaiian Electric above, the Company developed HELCO's Action Plan from a review of the resource plans developed and identified actions that demonstrated value that balanced risk and cost and provided flexibility across the evaluated scenarios. The Action Plan was not developed by solely selecting the "least cost" resource plan produced by the model since each scenario produced a different "least cost" plan. Instead, the Action Plan contains many of the elements of the resource plans from all the scenarios that were found to balance costs and risks, and provide other benefits. Relevant considerations are discussed in more detail in the following subsections of this report.

Demand Response

As discussed in *Chapter 8: Resource Planning and Analysis*, implementation of the Demand Response (DR) programs, in futures where load increases, provided capacity deferral benefits that exceeded the costs of the program. In futures with flat or decreasing loads, the DR programs did not provide capacity deferral benefits but did provide value by increasing the regulating capability of the system, which would allow for improved response to the increasing amount of variable renewable resources being added each year in any scenario. Properly implemented DR programs also could provide ancillary service benefits by contributing to the regulating reserve that is required to be carried on the system. Conversely, effective use of DR for system operation would result in less use of quick-starting generating resources.

Hu Honua

Hu Honua was assumed to be in service in 2014 in many of the plans. The inclusion of Hu Honua is supported by the analysis performed in HELCO's Application in Docket No. 2012-0212 (Exhibit 6, page 10), where the conclusion was the economic benefits over the 20-year term of the PPA are greater than the costs of the PPA. This conclusion is supported by the IRP analysis in all four scenarios, when comparing plans without Hu Honua and plans with Hu Honua and the associated Shipman decommissioning. (See *Appendix O: Resource Plan Sheets* for resource plans and costs. For Blazing a Bold Frontier, see plans H1_2B_X-1r0 and H1_2A_X-1r0. For Stuck in the Middle, see plans H2B2b_N-9r3 and H2B2a_N-9r7. For No Burning Desire, see plans H3_2B_X-1r0 and H3_2A_X-1r0. For Moved by Passion, see plans H4_2B_N-1R0 and H4_2A_N-1r0.

The Hu Honua project is consistent with State of Hawaii energy policy, which encourages the use and development of renewable energy. The Hu Honua project will help HELCO reduce its reliance on fossil fuels by displacing use of a significant amount of fossil fuel per year contribute to the Companies' Renewable Portfolio Standards. The Hu Honua facility will provide performance and operational features beneficial to system reliability, and similar to the capabilities of existing HELCO steam generation, including the provision of firm, dispatchable energy, inertial and primary frequency response, regulation and load following under HELCO's control, voltage regulation, and ability to ride through frequency and voltage disturbances.

The price of energy from Hu Honua will be delinked from the price of fossil fuels. Additionally, as it is located at the site of the former Hilo Coast Power Co. generator, not far from the Hilo load center, it is able to utilize existing transmission line infrastructure. Per the Qualitative Metrics Matrix (Chapter 17), biomass also preserves open space and is a productive and sustainable use of agricultural lands. However, the matrix lists concerns about biomass such as water requirements and contamination from pesticides.

Shipman 3 and 4

Shipman units 3 and 4 are currently on dry layup. The current plan is to decommission Shipman 3 and 4 after Hu Honua has been in service for a year while having shown reliable performance. If Hu Honua does not go into service, HELCO will still decommission Shipman 3 and 4 provided that there is sufficient generating capacity on the system to meet the expected future load growth.

Geothermal

In Order No. 31015 of Docket No. 2012-0092, the Commission approved the issuance of HELCO's Proposed Final Request for Proposals for Renewable Geothermal Dispatchable Energy and Firm Capacity Resources Island of Hawaii (Geothermal RFP) document. Through this RFP, HELCO is seeking up to 50 megawatts of qualified renewable geothermal dispatchable energy and firm capacity with a target date for commercial operation between 2018 and 2023, or earlier. In the action plan runs for Blazing a Bold Frontier and Stuck in the Middle, we assumed a geothermal resource was installed in 2018. For all four scenarios, the geothermal resource was determined to be a low cost resource, even with the addition of Hu Honua. Even for scenarios where capacity was not needed, a geothermal unit was added to reduce total resource cost in the study period. (See plans H1_2A_X-1br0, H2_2A_X-1Br0, H3_2A_N-1r0, and H4_2A_X-1Br0 in Appendix O.) In three out of the four resource plans, at least two 25 MW geothermal units were added in the planning period. The only exception was for Scenario 3, with lower oil prices, the 17 MW internal combustion engine was slightly less expensive so it was added after the first 25 MW geothermal unit.

The Geothermal resource reduces the consumption of fossil fuels and contributes to the renewable energy percentage. However, the Qualitative Metrics Matrix lists concerns with geothermal such as potential proximity to culturally sensitive areas, noise and health concerns in near proximity, and not showing respect to Pele. These concerns will be considered in the RFP process.

Environmental Compliance

As discussed in *Chapter 9: Environmental Regulation Compliance*, fuel switching strategies result in lower costs than the installation of Air Quality Control equipment. The availability and cost of the fuel, however, determines what fuel will be used in lieu of MSFO. Compliance with the NAAQS regulations could be accommodated by switching to industrial fuel oil with less than 0.75% sulfur (LSIFO), biofuels, or LNG by 2022. If LNG proves to be available in the future, it has the potential to provide the lowest rates compared to the other fuel options as shown in the environmental compliance analysis in Chapter 9. The HELCO action plan runs also show the potential of LNG to reduce costs (H1B1A_N-9R1 and H2B1a_N-9r4)

Biofuels

Biofuels are an integral part of HELCO's renewable energy strategy to actively seek and incorporate a diverse portfolio of new renewable resources. Biofuels, produced from local energy crops, have the following benefits: creates new jobs in Hawaii, retains the billions of dollars that are spent on imported oil in the State, increases Hawaii's energy security, invigorates Hawaii's agriculture industry, supports the State's goal of diversifying Hawaii's economy by encouraging the development of local agriculture, reduces greenhouse gas emissions, and provides a local fuel alternative for marine, land, and aviation transportation. Another important consideration is that biofuels can be used to generate renewable energy for existing conventional generating units which provide essential grid services, including load following, frequency response, voltage control, and on-line operating and spinning reserves. HELCO has submitted an application for the approval of a biodiesel supply contract with Aina Koa Pono-Kau LLC in Docket No. 2012-0185.

The Keahole combined cycle unit provides baseload generation and essential grid management services by maintaining generation in West Hawaii. In the HELCO action plan analysis for Blazing a Bold Frontier and Stuck in the Middle, the Keahole combined cycle unit are assumed to begin burning biofuels in 2018 in several select runs. For Stuck in the Middle which assumes high biofuel prices and reference oil prices, the results from the action plan runs indicate that burning biofuels in the Keahole combined cycle unit is higher cost when compared to burning diesel. (See plans H2B2a_N-9r1 and H2B2a_N-9r7.) However, for Blazing a Bold Frontier, which assumes low biofuel prices and high oil prices, burning biofuels in the Keahole combined cycle unit is cost effective. (See plans H1B2A_N-9R1 and H1B2A_N-9R3.)[121]

[121] It should be noted that the model used the forecasted market biofuel prices in the analysis and not the specific pricing from the AKP contract which is confidential so the scenario analysis should not be construed as applicable to the specifics detailed in the AKP contract, Docket No. 2012-0085.

Therefore, the final Resource Plans and Action Plan contain fuel switching activities for environmental compliance, working towards obtaining LNG in Hawaii, and periodically testing the biofuels market.

Puna Biomass Conversion

The conversion of the Puna steam unit from burning oil to wood biomass was evaluated in Blazing a Bold Frontier and Stuck in the Middle. (See plans H1B2A_N-9R1/H1B2A_N-9R2 for Blazing a Bold Frontier and H2B2a_N-9r7/H2B2a_N-9r8 for Stuck in the Middle.) Although the Puna biomass conversion was marginally more expensive than not doing the conversion under assumptions used in the analysis, the project does have positive impacts such as reducing emissions and fossil fuel consumption while contributing to the renewable energy percentage. Another consideration is that the actual cost of converting the Puna steam unit to biomass may be less than the cost assumption used in the IRP analysis which warrants further investigation.

Wind and Photovoltaics

As in the analysis for Hawaiian Electric, wind and PV resources were found to be the most cost competitive resources in all four scenarios. This is shown in the resource plans in Appendix O, where wind and PV resources are found in almost all of the plans when they were allowed to be selected by the model. Wind and PV were cost competitive against other resource options and the cost of operating the existing system based on the assumptions of the various scenarios. It means that at this time, given the cost assumptions used in the analysis, PV and wind were selected by the model as more cost competitive than other resources under the given scenarios evaluated. The scenario analysis does not account for technical issues associated with the interconnection of additional variable renewable energy, including PV and wind, which may have negative impacts to reliability and circuit penetration. It should be noted that the IRP analysis did not include detailed grid stability analysis or intra-hour analysis, as these types of studies are for shorter time frames (that is, hours, months, one year) whereas the IRP is conducted over a 20-year time frame. Any technical issues associated with interconnection of additional variable renewable energy will be addressed as discussed in *Chapter 16: Integrating High Penetration of Variable Distributed Generation*.

New Capacity

The scenario analysis confirmed the uncertainty the Company faces with respect to the need to plan for and add new capacity to meet the planning criteria. The analysis shows that the need to add new capacity is influenced by these factors:

- Peak load and its driving factors which are illustrated by the scenarios. The differences in timing between the plans H1_2A_N-1r0, H2_2A_N-1r0, H3_2A_N-1r0, and H4_2A_N-1r0.

- Whether low cost renewable energy can replace older existing fossil generation.
- Whether purchase power generation is placed into service. See previous Hu Honua and Geothermal RFP discussion above.
- Deactivation and decommissioning of existing resources. In the Environmental Compliance section, see the capacity timing differences between plans H1B2A_X-2Ar1 and H1B2a_X-4Ar3B; H2B2a_X-2Ar1 and H2B2a_X-4Ar3b; H3B2A_N-2r2 and H3B2A_N-4r3b; H4B2A_X-2Ar3 and H4B2A_X-4Ar3b.

Therefore, any RFP for new capacity will need to take into account the influence of these factors to determine the timing and size of needed capacity.

Energy Storage

As discussed in *Chapter 8: Resource Planning and Analysis*, energy storage can reduce curtailment of renewable energy. Given this and other operational benefits being evaluated as part of ongoing investigations and demonstration projects, an energy storage project is included in the Company's Action Plan. Currently HELCO is engaged in various collaborative projects for energy storage. HELCO is working with Hawaii Natural Energy Institute to evaluate a 1MW/250kWh fast-response lithium titanate BESS to smooth the output of the Hawi wind farm. Also, HELCO is evaluating two 100kW/248 kWh lithium ion BESS installed at two customer-owned PV projects in July 2012.

Qualitative Metrics

From a qualitative perspective (Qualitative Metrics Matrix in Chapter 17), utility scale battery storage can creates jobs, may be a robust way to enable demand response resource, and provides ancillary services for the utility. However, these benefits are offset in part by issues such as large land use footprint, potential chemical contamination, and potential fire hazard.

Hawaii Electric Light Company Resource Plans

As required by the Framework, the Company has developed alternative Resource Plans based on review of the analysis and resource plans (shown in Appendix O). The four Resource Plans are designated as the Preferred Resource Plan, Contingency Resource Plan, Parallel Resource Plan, and Secondary Resource Plan (see Table 19-5 and Table 19-7). These plans identify resources and describe generally what the 20 year plans may look like if the future were to unfold as described by the particular scenario. The Company chose to describe the four plans in two Scenarios: Blazing a Bold Frontier and Stuck in the Middle (the "Reference Case") which represent two divergent futures that could occur. In contrast to prior IRPs produced by the Companies, the Action Plan supports implementation of all four of these plans. In prior IRPs, the Action Plan was specifically correlated to the Preferred Plan.

Quantitative metrics for the four plans are provided in Appendix P for the two scenarios. Qualitative metrics applicable to the resources shown on the plan are described in Chapter 17. These plans support protection of Hawaii's environment by reducing greenhouse gases, sulfur based emissions, nitrous oxides, and particulate emissions. They reduce the dependency on imported fossil fuels by dramatically increasing the percent of energy generated by renewable resources. The portfolio of resources increases diversity which strengthens Hawaii's energy independence by the reduction in dependency on any single type of resource. Operating flexibility of the system improves with increases in system regulating capability. The plans also identify challenges that lie ahead including operating the system as the variable energy resource penetration on the grid increases to unprecedented levels and the opportunity to improve operating flexibility to mitigate system constraints to decrease or eliminate curtailed renewable energy. The intent is also to minimize the amount of intermittent renewable energy that is otherwise curtailed.

Table 19-5. HELCO Preferred and Contingency Resource Plans: Blazing a Bold Frontier

Blazing a Bold Frontier			Preferred Resource Plan Fuel Switch to LSIFO	Contingency Plan Fuel Switch to LNG
Name	**Self Generation**		**H1B2A_N-9R3**	**H1B1A_N-9R1**
Plan	Annual	Cumulative	Year 2022 Fuel Switch to LSIFO No LNG	Year 2022 Fuel Switch to LNG
Notes			Fuel Switch to LSIFO for Hill 5, Hill 6, Puna; Cycle Hill 5–6, Puna Steam; New CIDLC, Fast DR, RDLCWH, RDLCAC; 75%+25%+10% PBFA DSM	Fuel Switch to LNG for Hill 5, Hill 6, Puna, Keahole; Cycle Hill 5–6, Puna Steam; New CIDLC, Fast DR, RDLCWH, RDLCAC; 75%+25%+10% PBFA DSM
Reference			10 MW Wind (HW04): 2020 5 MW PV (HP03): 2020 25 MW Geothermal (HG02): 2022	10 MW Wind (HW04): 2020 5 MW PV (HP03): 2020 25 MW Geothermal (HG02): 2022
2014	4MW	14MW	Hu Honua (21.5MW)	Hu Honua (21.5MW)
2015	4MW	18MW	Decommission Shipman 3 (–6.8 MW)	Decommission Shipman 3 (–6.8 MW)
			Decommission Shipman 4 (–6.7 MW)	Decommission Shipman 4 (–6.7 MW)
2016	4MW	22MW		
2017	4MW	25MW		
2018	3MW	28MW	Add 25MW geothermal (HG01x1)	Add 25MW geothermal (HG01x1)
2019	3MW	32MW		
2020	3MW	35MW	Add 5MW PV (HP03x5)	Add 5MW PV (HP03x5)
			Add 10MW wind (HW04x1)	Add 10MW wind (HW04x1)
2021	3MW	38MW	Add 10MW wind (HW04x1)	Add 10MW wind (HW04x1)
2022	3MW	41MW	Fuel switch to LSIFO (Hill 5/6, Puna Steam)	Fuel switch to LNG (Hill 5/6, Puna Steam, Keahole CC)
			Add 5MW PV (HP03x5)	
2023	3MW	43MW		
2024	3MW	46MW		
2025	3MW	49MW		
2026	3MW	52MW		
2027	3MW	55MW		
2028	3MW	59MW		
2029	3MW	61MW		
2030	3MW	64MW	Add 10MW wind (HW04x1)	Add 10MW wind (HW04x1)
2031	3MW	67MW	Add 10MW wind (HW04x1)	Add 10MW wind (HW04x1)
2032	3MW	71MW		
2033	3MW	73MW		
Strategist Planning Period Total Cost			4,242,743	4,129,452
Strategist Study Period Total Cost			5,752,597	5,522,871

Blazing a Bold Frontier			**Preferred Resource Plan Fuel Switch to LSIFO**	**Contingency Plan Fuel Switch to LNG**
Name	**Self Generation**		**H1B2A_N-9R3**	**H1B1A_N-9R1**
Planning Period Total Cost			4,888,918	4,781,942
Study Period Total Cost			6,398,772	6,175,361
Planning Rank			2	1
Study Rank			2	1

Table 19-6. HELCO Parallel and Secondary Resource Plans: Blazing a Bold Frontier

Blazing a Bold Frontier			**Parallel Plan With Biodiesel**	**Secondary Plan Puna Biomass**
Name	**Self Generation**		**H1B1A_N-9R2**	**H1B2B_N-9R1**
Plan	Annual	Cumulative	Year 2022 Fuel Switch to LNG	Year 2022 Fuel Switch to LSIFO No Hu Honua, No Biofuels Convert Puna to Biomass
Notes			Fuel Switch to LNG for Hill 5, Hill 6, Puna; Cycle Hill 5–6, Puna Steam; New CIDLC, Fast DR, RDLCWH, RDLCAC; 75%+25%+10% PBFA DSM	Fuel Switch to LSIFO for Hill 5 & 6; Puna biomass; Cycle Hill 5–6, Puna Steam; New CIDLC, Fast DR, RDLCWH, RDLCAC; 75%+25%+10% PBFA DSM
Reference			10 MW Wind (HW04): 2020 5 MW PV (HP03): 2020 25 MW Geothermal (HG02): 2022	10 MW Wind (HW04): 2020 5 MW PV (HP03): 2020 25 MW Geothermal (HG02): 2022
2014	4MW	14MW	Hu Honua (21.5MW)	Baseload Hill 6
2015	4MW	18MW	Decommission Shipman 3 (–6.8 MW)	Decommission Shipman 3 (–6.8 MW)
			Decommission Shipman 4 (–6.7 MW)	Decommission Shipman 4 (–6.7 MW)
2016	4MW	22MW		
2017	4MW	25MW		Convert Puna to biomass (HRP1)
2018	3MW	28MW	Add 25MW geothermal (HG01x1)	Add 25MW geothermal (HG01x1)
			Biofuel conversion of Keahole CC	
2019	3MW	32MW		
2020	3MW	35MW		Add 5MW PV (HP03x5)
			Add 10MW wind (HW04x1)	Add 10MW wind (HW04x1)
2021	3MW	38MW	Add 10MW wind (HW04x1)	Add 10MW wind (HW04x1)
2022	3MW	41MW	Fuel switch to LNG (Hill 5/6, Puna Steam)	Fuel switch to LSIFO (Hill 5/6)
				Add 5MW PV (HP03x5)
2023	3MW	43MW		Add 5MW PV (HP03x5)
2024	3MW	46MW		
2025	3MW	49MW		
2026	3MW	52MW		
2027	3MW	55MW		
2028	3MW	59MW		
2029	3MW	61MW		
2030	3MW	64MW		Add 10MW wind (HW04x1)
2031	3MW	67MW		Add 10MW wind (HW04x1)
2032	3MW	71MW		
2033	3MW	73MW	Add 10MW wind (HW04x1)	
Strategist Planning Period Total Cost			3,947,167	4,466,290
Strategist Study Period Total Cost			5,192,676	5,986,669

Blazing a Bold Frontier			**Parallel Plan With Biodiesel**	**Secondary Plan Puna Biomass**
Name	**Self Generation**		**H1B1A_N-9R2**	**H1B2B_N-9R1**
Planning Period Total Cost			4,599,657	5,112,465
Study Period Total Cost			5,845,166	6,632,844
Planning Rank			1	2
Study Rank			1	2

Table 19-7. HELCO Preferred and Contingency Resource Plans: Stuck in the Middle

Stuck in the Middle			**Preferred Resource Plan Fuel Switch to LSIFO**	**Contingency Plan Fuel Switch to LNG**
Name	**Self Generation**		**H2B2a_N-9r7**	**H2B1a_N-9r4**
Plan	Annual	Cumulative	Year 2022 Fuel Switch to LSIFO No LNG	Year 2022 Fuel Switch to LNG
Notes			Fuel Switch to LSIFO for Hill 5, Hill 6, Puna Cycle Hill 5–6, Puna Steam New CIDLC, Fast DR, RDLCWH, RDLCAC 75% PBFA DSM	Fuel Switch to LNG for Hill 5, Hill 6, Puna, Keahole Cycle Hill 5–6, Puna Steam New CIDLC, Fast DR, RDLCWH, RDLCAC 75% PBFA DSM
Resources Available			10 MW Wind (HW04): 2020 5 MW PV (HP03): 2020 25 MW Geothermal (HG02): 2020	10 MW Wind (HW04): 2020 5 MW PV (HP03): 2015 25 MW Geothermal (HG02): 2020
2014	2MW	8MW	Hu Honua (21.5MW)	Hu Honua (21.5MW)
2015	2MW	10MW	Decommission Shipman 3 (–6.8 MW)	Decommission Shipman 3 (–6.8 MW)
			Decommission Shipman 4 (–6.7 MW)	Decommission Shipman 4 (–6.7 MW)
2016	2MW	12MW		
2017	2MW	14MW		
2018	2MW	15MW	Add 25MW geothermal (HG01x1)	Add 25MW geothermal (HG01x1)
2019	2MW	17MW		
2020	2MW	19MW	Add 10MW wind (HW04x1)	Add 10MW wind (HW04x1)
2021	2MW	21MW	Add 5MW PV(HP03x5)	
			Add 10MW wind (HW04x1)	Add 10MW wind (HW04x1)
2022	2MW	22MW	Fuel switch to LSIFO (Hill 5/6, Puna Steam)	Fuel switch to LNG (Hill 5/6, Puna Steam, Keahole CC)
			Add 5MW PV(HP03x5)	Add 5MW PV(HP03x5)
2023	1MW	24MW	Add 5MW PV(HP03x5)	Add 5MW PV(HP03x5)
2024	2MW	25MW	Add 5MW PV(HP03x5)	Add 5MW PV(HP03x5)
2025	2MW	27MW		Add 5MW PV(HP03x5)
2026	2MW	29MW		
2027	2MW	30MW		
2028	2MW	32MW	Add 5MW PV(HP03x5)	Add 5MW PV(HP03x5)
2029	2MW	33MW	Add 5MW PV(HP03x5)	Add 5MW PV(HP03x5)
2030	2MW	35MW	Add 10MW wind (HW04x1)	Add 10MW wind (HW04x1)
2031	2MW	37MW	Add 10MW wind (HW04x1)	Add 10MW wind (HW04x1)
2032	2MW	38MW		
2033	1MW	40MW	Add 25MW geothermal (HG02x1)	Add 25MW geothermal (HG02x1)
			Add 5MW PV(HP03x5)	Add 5MW PV(HP03x5)
Strategist Planning Period Total Cost			4,010,886	3,974,155

Stuck in the Middle			**Preferred Resource Plan** **Fuel Switch to LSIFO**	**Contingency Plan Fuel Switch to LNG**
Name	**Self Generation**		**H2B2a_N-9r7**	**H2B1a_N-9r4**
Strategist Study Period Total Cost			5,975,412	5,899,553
Planning Period Total Cost			4,657,060	4,626,644
Study Period Total Cost			6,621,586	6,552,043
Planning Rank			2	1
Study Rank			2	1

Table 19-8. HELCO Parallel and Secondary Resource Plans: Stuck in the Middle

Stuck in the Middle			**Parallel Plan With Biodiesel**	**Secondary Plan Puna Biomass**
Name	**Self Generation**		**H2B1a_N-9r5**	**H2B2b_N-9r14**
Plan	Annual	Cumulative	Year 2022 Fuel Switch to LNG	Year 2022 Fuel Switch to LSIFO No Hu Honua, No Biofuels Convert Puna to Biomass
Notes			Fuel Switch to LNG for Hill 5, Hill 6, Puna Cycle Hill 5–6, Puna Steam New CIDLC, Fast DR, RDLCWH, RDLCAC 75% PBFA DSM	Fuel Switch to LSIFO for Hill 5, Hill 6 Cycle Hill 5–6, Puna Steam New CIDLC, Fast DR, RDLCWH, RDLCAC 75% PBFA DSM
Resources Available			10 MW Wind (HW04): 2020 5 MW PV (HP03): 2015 25 MW Geothermal (HG02): 2020	10 MW Wind (HW04): 2020 5 MW PV (HP03): 2015 25 MW Geothermal (HG02): 2020
2014	2MW	8MW	Hu Honua (21.5MW)	Baseload Hill 6
2015	2MW	10MW	Decommission Shipman 3 (–6.8 MW)	
			Decommission Shipman 4 (–6.7 MW)	
2016	2MW	12MW		
2017	2MW	14MW		Convert Puna to biomass (HRP1)
2018	2MW	15MW	Add 25MW geothermal (HG01x1)	Add 25MW geothermal (HG01x1)
			Biofuel conversion of Keahole CC	Decommission Shipman 3 (–6.8 MW)
				Decommission Shipman 4 (–6.7 MW)
2019	2MW	17MW		
2020	2MW	19MW	Add 10MW wind (HW04x1)	Add 10MW wind (HW04x1)
2021	2MW	21MW	Add 10MW wind (HW04x1)	Add 10MW wind (HW04x1)
2022	2MW	22MW	Fuel switch to LNG (Hill 5/6, Puna Steam)	Fuel switch to LSIFO (Hill 5/6)
			Add 5MW PV(HP03x5)	
2023	1MW	24MW	Add 5MW PV(HP03x5)	Add 5MW PV(HP03x5)
2024	2MW	25MW	Add 5MW PV(HP03x5)	
2025	2MW	27MW	Add 5MW PV(HP03x5)	Add 5MW PV(HP03x5)
2026	2MW	29MW		Add 5MW PV(HP03x5)
2027	2MW	30MW		Add 5MW PV(HP03x5)
2028	2MW	32MW	Add 5MW PV(HP03x5)	Add 5MW PV(HP03x5)
2029	2MW	33MW	Add 5MW PV(HP03x5)	
2030	2MW	35MW	Add 10MW wind (HW04x1)	Add 10MW wind (HW04x1)
2031	2MW	37MW	Add 10MW wind (HW04x1)	Add 10MW wind (HW04x1)
2032	2MW	38MW		Add 5MW PV(HP03x5)
2033	1MW	40MW	Add 25MW geothermal (HG02x1)	Add 25MW geothermal (HG02x1)
			Add 5MW PV(HP03x5)	Add 5MW PV(HP03x5)
Strategist Planning Period Total Cost			4,370,517	4,051,957

Stuck in the Middle			**Parallel Plan With Biodiesel**	**Secondary Plan Puna Biomass**
Name	**Self Generation**		**H2B1a_N-9r5**	**H2B2b_N-9r14**
Strategist Study Period Total Cost			6,309,314	6,046,157
Planning Period Total Cost			5,023,007	4,698,132
Study Period Total Cost			6,961,805	6,692,331
Planning Rank			2	1
Study Rank			2	1

Considerations for the MECO Resource and Action Plans

The Company reviewed the resource plans and identified actions that demonstrated value and provided flexibility across the evaluated scenarios. The Action Plan was not formed by simply selecting a least cost resource plan because such a plan would not be robust across all the scenarios. Instead, the Action Plan is composed of a variety of elements from the full set of resource plans from all the scenarios that were found to balance costs and risks, and provide other system benefits.

Demand Response

Expanding the Demand Response (DR) programs, beyond the current Fast DR program, provides capacity deferral benefits particularly in scenarios where there is load growth. Expanded DR programs increase the regulating capability of the system and provide ancillary benefits by providing a lower cost contribution to regulating reserve that will allow the system to better respond to the increasing amount of variable renewable resources being added. Conversely, effective use of DR for system operation would result in less use of quick-starting generating resources.

Decommissioning and Deactivating Units

In Blazing a Bold Frontier, where the load is steadily decreasing, Kahului 1 through 4 can be deactivated without any future capacity additions needed. In Stuck in the Middle where there is modest load growth, the deactivation of Kahului 1 through 4 prompts an additional capacity need in the same year to replace decommissioned units. (See runs M1_2a_N-1r4 and M2_2__N-1r6 that illustrate this difference between the scenarios.) Maalaea 4-9 were also considered to be deactivated in addition to Kahului 1-4. See runs M1B1A_N-4CR15-2 and M2B1A_N-4CR15 to see the difference in firm capacity requirements between the resource plans with Maalaea and Kahului deactivations.

HC&S

The HC&S contract was modeled to end in 2014 for most resource plans, since the current power purchase agreement with HC&S is in effect through this year. As a sensitivity, the HC&S contract was extended indefinitely through the study period in some resource plans (see plan M2_2b_N-1r0). With HC&S extended indefinitely and no deactivations of existing unit, MECO is able to defer future capacity need out to 2029 under the Stuck in the Middle scenario. MECO and HC&S are currently in discussion of HC&S continuing through the end of 2017. Although HC&S would not be defering capacity if the contract ends in 2017, it still provides renewable energy contributing to the RPS while in service.

Environmental Compliance

Fuel switching strategies result in lower costs compared to the installation of Air Quality Control equipment. The availability and cost of the fuel however, will ultimately determine what fuel will be used. Future compliance with NAAQS can be met by switching to diesel fuels with less than 0.05% sulfur, biofuels, or LNG by 2022. If LNG proves to be available in the future, it has the potential to provide the lowest customer rates compared to all other fuel options. For the Maui system, the dual train combined cycle units at Maalaea would be converted to LNG as shown in the preferred resource plan (see M2B1A_N-4CR12).

Wind and Photovoltaics

Wind and PV resources were found to be the most cost competitive resources in all four scenarios. This is shown in the resource plans in Appendix O, where wind and PV resources are found in almost all of the plans when they were allowed to be selected by the model. This does not mean that other renewable resources such as wave energy or OTEC could not be added in the future. It means that at this time, given the cost assumptions used in the analysis, PV and wind were selected by the model as more cost competitive than other resources under the given scenarios evaluated. The scenario analysis does not account for technical issues associated with the interconnection of additional variable renewable energy, including PV and wind, which may have negative impacts to reliability and circuit penetration. It should be noted that the IRP analysis did not include detailed grid stability analysis or intra-hour analysis, as these types of studies are for shorter time frames (that is, hours, months, one year) whereas the IRP is conducted over a 20-year time frame. Any technical issues associated with interconnection of additional variable renewable energy will be addressed as discussed in Chapter 16. The model also has limitations on the treatment of curtailment of variable generation because it is not an hourly chronological production simulation.

New Capacity

The scenario analysis confirmed the uncertainty the Company faces with respect to the need to plan for and add new capacity to meet the planning criteria. The analysis shows that the need to add new capacity is influenced by these factors:

- Peak load and its driving factors which are illustrated by the scenarios. The differences in timing between the plans M1_2a_N-1r3, M2_2__N-1r1, M3_2__N-1r1, and M4_2a_N-1r0.
- Whether purchase power contracts end or are extended. See previous HC&S discussion above.
- The extent to which demand response can defer the necessary capacity.

- Deactivation and decommissioning of existing resources. See difference between M1_2a_N-1r3 and M1_2a_N-1r4; M2_2__N-1r5 and M2_2__N-1r6
- Whether and to what extent can wind provide capacity value.
- The extent to which energy storage can enable less curtailment of variable renewable energy.

Therefore, any RFP for new capacity will need to take into account the influence of these factors to determine the timing and size of needed capacity.

Energy Storage

As discussed in Chapter 8, energy storage can reduce curtailment of renewable energy. Given this and other operational benefits being evaluated as part of ongoing investigations and demonstration projects, an energy storage project was included in the action plan with installation in 2017.

Qualitative Metrics

From a qualitative perspective (Qualitative Metrics Matrix), utility scale battery storage can creates jobs, may be a robust way to enable demand response resource, and provides ancillary services for the utility. However, these benefits are offset in part by issues such as large land use footprint, potential chemical contamination, and potential fire hazard.

Maui Electric Resource Plans

As required by the Framework, the Company has developed alternate Resource Plans based on review of the analysis and resource plans (shown in Appendix O). The four Resource Plans are designated as the Preferred Resource Plan, Contingency Resource Plan, Parallel Resource Plan. and Secondary Resource Plan (see Table 19-9 and Table 19-11). These plans identify resources and describe generally what the 20 year plans would look like if the future were to unfold as described by the particular scenario. The Company chose to describe the four plans in two Scenarios: Blazing a Bold Frontier and Stuck in the Middle (the "Reference Case"), which represent two divergent futures that could occur. In contrast to prior IRPs produced by the Companies, the Action Plan supports implementation of all four of these plans. In prior IRPs, the Action Plan was specifically correlated to the Preferred Plan.

Table 19-13 and Table 19-14 show the Preferred Resource Plan, Contingency Resource Plan, Parallel Resource Plan, and Secondary Resource Plans for Lanai under the Blazing a Bold Frontier and Stuck in the Middle scenarios, respectively.

Table 19-15 and Table 19-16 show the Preferred Resource Plan, Contingency Resource Plan, Parallel Resource Plan, and Secondary Resource Plans for

Molokai under the Blazing a Bold Frontier and Stuck in the Middle scenarios, respectively.

Quantitative metrics for the four plans are provided in Appendix P for the two scenarios. Qualitative metrics applicable to the resources shown on the plan are described in Chapter 17. These plans support protection of Hawaii's environment by reducing greenhouse gases, sulfur oxide emissions, oxides of nitrogen, and particulate matter emissions. They reduce the dependency on imported fossil fuels by dramatically increasing the percent of energy generated by renewable resources. Operating flexibility of the system improves with increases in system regulating capability. The plans also identify challenges that lie ahead including operating the system as the variable energy resource penetration on the grid increases to unprecedented levels and the opportunity to improve operating flexibility to mitigate system constraints to decrease or eliminate curtailed renewable energy.

Table 19-9. Maui Preferred and Contingency Resource Plans: Blazing a Bold Frontier

Blazing a Bold Frontier			**Preferred Plan**	**Contingency**
Name	**Self Generation**		**MIBIA_N-4CR12-2**	**MIBIA_N-4CR13-2**
Plan	Annual	Cumulative	Retire K1–K4, LNG, Battery	Retire K1–K4, DG, Battery
Notes				
Resources Available			10 MW Wind (MW04): 2023 1 MW PV (MP03): 2023 17 MW ICE (MS01): 2019 25 MW Geothermal (MG02): 2019	10 MW Wind (MW04): 2023 1 MW PV (MP03): 2023 5 MW ICE (MS14): 2018 17 MW ICE (MS01): 2021 25 MW Geothermal (MG02): 2021
Reference				
DR & DSM Assumptions			110% of Base EEPS All DR: CIDLC Exp, RDLC Exp, Fast DR	110% of Base EEPS All DR: CIDLC Exp, RDLC Exp, Fast DR
2014	17MW	40MW	HC&S contract ends (–12 MW)	HC&S contract ends (–12 MW)
2015	16MW	56MW		
2016	17MW	73MW		
2017	16MW	89MW	Battery storage (MB01)	Battery storage (MB01)
2018	14MW	103MW		Add 5 MW ICE (MS14x1); biofuel
2019	10MW	113MW	Deactivate K1, K2, K3, K4 Add 34 MW ICE (MS01x2); biofuel	
2020	8MW	121MW		
2021	5MW	126MW	Fuel switch to LNG (Maalaea DTCCs)	Deactivate K1, K2, K3, K4 Add 34 MW ICE (MS01x2); biofuel
2022	4MW	130MW	Fuel switch to ULSD (M4–9)	Fuel switch to ULSD (All Maalaea)
2023	3MW	134MW		
2024	3MW	137MW		
2025	2MW	138MW		
2026	2MW	140MW		
2027	2MW	142MW		
2028	2MW	144MW		
2029	1MW	145MW		
2030	1MW	146MW		
2031	1MW	147MW		
2032	2MW	149MW		
2033	1MW	149MW		
Strategist Planning Period Total Cost			4,945,701	5,643,103
Strategist Study Period Total Cost			6,272,255	7,551,086

Blazing a Bold Frontier			**Preferred Plan**	**Contingency**
Name	**Self Generation**		**M1B1A_N-4CR12-2**	**M1B1A_N-4CR13-2**
Planning Period Total Cost			5,707,032	6,393,846
Study Period Total Cost			7,033,585	8,301,829
Planning Rank			1	2
Study Rank			1	2

Table 19-10. Maui Parallel and Secondary Resource Plans: Blazing a Bold Frontier

Blazing a Bold Frontier			**Parallel**	**Secondary Plan**
Name	**Self Generation**		**M1B1A_N-4CR14-2**	**M1B1A_N-4CR15-2**
Plan	Annual	Cumulative	Retire K1–K4, Battery	Retire K1–K4 & M4–M9, Battery
Resources Available			10 MW Wind (MW04): 2023 1 MW PV (MP03): 2023 17 MW ICE (MS01): 2019 25 MW Geothermal (MG02): 2019	10 MW Wind (MW04): 2023 1 MW PV (MP03): 2023 17 MW ICE (MS01): 2019 25 MW Geothermal (MG02): 2019
DR & DSM Assumptions			110% of Base EEPS All DR: CIDLC Exp, RDLC Exp, Fast DR	110% of Base EEPS All DR: CIDLC Exp, RDLC Exp, Fast DR
2014	17MW	40MW	HC&S contract extended to end of 2017	HC&S contract extended to end of 2017
2015	16MW	56MW		
2016	17MW	73MW		
2017	16MW	89MW	Battery storage (MB01)	Battery storage (MB01)
2018	14MW	103MW	HC&S contract ends (–12 MW)	HC&S contract ends (–12 MW)
2019	10MW	113MW	Deactivate K1, K2, K3, K4 Add 34 MW ICE (MS01x2); biofuel	Deactivate K1, K2, K3, K4 Add 34 MW ICE (MS01x2); biofuel
2020	8MW	121MW		
2021	5MW	126MW		
2022	4MW	130MW	Fuel switch to ULSD (All Maalaea)	Deactivate M4–M9 Add 34 MW ICE (MS01x2); biofuel Fuel switch to ULSD (Maalaea DTCCs)
2023	3MW	134MW		
2024	3MW	137MW		
2025	2MW	138MW		
2026	2MW	140MW		
2027	2MW	142MW		
2028	2MW	144MW		
2029	1MW	145MW		
2030	1MW	146MW		
2031	1MW	147MW		
2032	2MW	149MW		
2033	1MW	149MW		
Strategist Planning Period Total Cost			5,477,140	5,599,445
Strategist Study Period Total Cost			7,365,908	7,548,956
Planning Period Total Cost			6,228,997	6,351,302
Study Period Total Cost			8,117,764	8,300,813

Blazing a Bold Frontier			Parallel	Secondary Plan
Name	**Self Generation**		**M1B1A_N-4CR14-2**	**M1B1A_N-4CR15-2**
Planning Rank			1	2
Study Rank			1	2

Table 19-11. Maui Preferred and Contingency Resource Plans: Stuck in the Middle

Stuck in the Middle			**Preferred Plan**	**Contingency**
Name	**Self Generation**		**M2B1A_N-4CR12**	**M2B1A_N-4CR13**
Plan	Annual	Cumulative	Retire K1–K4, LNG, Battery	Retire K1–K4, DG, Battery
Resources Available			10 MW Wind (MW04): 2023 1 MW PV (MP03): 2023 17 MW ICE (MS01): 2019 25 MW Geothermal (MG02): 2019	10 MW Wind (MW04): 2023 1 MW PV (MP03): 2023 5 MW ICE (MS14): 2018 17 MW ICE (MS01): 2021 25 MW Geothermal (MG02): 2021
DR & DSM Assumptions			75% of Base EEPS All DR: CIDLC Exp, RDLC Exp, Fast DR	75% of Base EEPS All DR: CIDLC Exp, RDLC Exp, Fast DR
2014	9MW	22MW	HC&S contract ends (–12 MW)	HC&S contract ends (–12 MW)
2015	9MW	31MW		
2016	9MW	40MW		
2017	9MW	49MW	Battery storage (MB01)	Battery storage (MB01)
2018	8MW	56MW		Add 5 MW ICE (MS14x1); biofuel
2019	5MW	62MW	Deactivate K1, K2, K3, K4 Add 34 MW ICE (MS01x2); biofuel	
2020	4MW	66MW		
2021	3MW	69MW	Fuel switch to LNG (Maalaea DTCCs)	Deactivate K1, K2, K3, K4 Add 34 MW ICE (MS01x2); biofuel
2022	2MW	71MW	Fuel switch to ULSD (M4–M9)	Fuel switch to ULSD (All Maalaea)
2023	2MW	73MW	Add 30 MW wind (MW04x3)	Add 30 MW wind (MW04x3)
2024	2MW	74MW	Add 30 MW wind (MW04x3)	Add 30 MW wind (MW04x3)
2025	1MW	75MW	Add 30 MW wind (MW04x3)	Add 30 MW wind (MW04x3)
2026	1MW	76MW	Add 17 MW ICE (MS01x1); biofuel	
2027	1MW	77MW		
2028	1MW	78MW		
2029	1MW	79MW		
2030	1MW	80MW		
2031	1MW	80MW		Add 5 MW PV (MP03x5)
2032	1MW	81MW		Add 5 MW PV (MP03x5)
2033	0MW	81MW		Add 5 MW PV (MP03x5)
Strategist Planning Period Total Cost			3,950,977	4,098,852
Strategist Study Period Total Cost			5,598,451	5,880,824
Planning Period Total Cost			4,712,308	4,849,585

Stuck in the Middle			**Preferred Plan**	**Contingency**
Name	**Self Generation**		**M2B1A_N-4CR12**	**M2B1A_N-4CR13**
Study Period Total Cost			6,359,781	6,631,567
Planning Rank			1	2
Study Rank			1	2

Table 19-12. Maui Parallel and Secondary Resource Plans: Stuck in the Middle

Stuck in the Middle			Parallel	Secondary Plan
Name	**Self Generation**		**M2B1A_N-4CR14**	**M2B1A_N-4CR15**
Plan	Annual	Cumulative	Retire K1–K4, Battery	Retire K1–K4 & M4–M9, Battery
Resources Available			10 MW Wind (MW04): 2023 1 MW PV (MP03): 2023 17 MW ICE (MS01): 2019 25 MW Geothermal (MG02): 2019	10 MW Wind (MW04): 2023 1 MW PV (MP03): 2023 17 MW ICE (MS01): 2019 25 MW Geothermal (MG02): 2019
DR & DSM Assumptions			75% of Base EEPS All DR: CIDLC Exp, RDLC Exp, Fast DR	75% of Base EEPS All DR: CIDLC Exp, RDLC Exp, Fast DR
2014	9MW	22MW	HC&S contract extended to end of 2017	HC&S contract extended to end of 2017
2015	9MW	31MW		
2016	9MW	40MW		
2017	9MW	49MW	Battery storage (MB01)	Battery storage (MB01)
2018	8MW	56MW	HC&S contract ends (–12 MW)	HC&S contract ends (–12 MW)
2019	5MW	62MW	Deactivate K1, K2, K3, K4 Add 34 MW ICE (MS01x2); biofuel	Deactivate K1, K2, K3, K4 Add 34 MW ICE (MS01x2); biofuel
2020	4MW	66MW		
2021	3MW	69MW		
2022	2MW	71MW	Fuel switch to ULSD (All Maalaea)	Deactivate M4–M9 Add 34 MW ICE (MS01x2); biofuel Fuel switch to ULSD (Maalaea DTCCs)
2023	2MW	73MW	Add 30 MW wind (MW04x3)	Add 30 MW wind (MW04x3)
2024	2MW	74MW	Add 30 MW wind (MW04x3)	Add 30 MW wind (MW04x3)
2025	1MW	75MW	Add 30 MW wind (MW04x3)	Add 30 MW wind (MW04x3)
2026	1MW	76MW	Add 17 MW ICE (MS01x1); biofuel	
2027	1MW	77MW		Add 17 MW ICE (MS01x1); biofuel
2028	1MW	78MW		
2029	1MW	79MW		
2030	1MW	80MW		
2031	1MW	80MW	Add 5 MW PV (MP03x5)	Add 5 MW PV (MP03x5)
2032	1MW	81MW	Add 5 MW PV (MP03x5)	Add 5 MW PV (MP03x5)
2033	0MW	81MW	Add 5 MW PV (MP03x5)	Add 5 MW PV (MP03x5)
Strategist Planning Period Total Cost			4,103,679	4,230,850
Strategist Study Period Total Cost			5,902,516	6,092,532
Planning Period Total Cost			4,855,521	4,982,710
Study Period Total Cost			6,654,373	6,844,389

Stuck in the Middle			Parallel	Secondary Plan
Name	**Self Generation**		**M2B1A_N-4CR14**	**M2B1A_N-4CR15**
Planning Rank			1	2
Study Rank			1	2

Table 19-13. Lanai Preferred, Contingency, Parallel, and Secondary Resource Plans: Blazing a Bold Frontier

	Preferred Plan	**Contingency**	**Parallel**	**Secondary**
Name	**ML-1**	**ML-2**	**ML-3**	**ML-4**
Plan	LNG short-term, biomass	LNG long-term, biomass	100% renewable, biomass, biodiesel	100% renewable, PV, battery, biodiesel
Resources Available	600 kW Wind: 2018 750 kW Wave: 2019 1.0 MW PV: 2018 1.0 MW Biomass: 2018	600 kW Wind: 2018 750 kW Wave: 2019 1.0 MW PV: 2018 1.0 MW Biomass: 2018	600 kW Wind: 2018 750 kW Wave: 2019 1.0 MW PV: 2018 1.0 MW Biomass: 2018	600 kW Wind: 2018 750 kW Wave: 2019 1.0 MW PV: 2018 1.0 MW Biomass: 2018
Reference				
2014			Fuel switch to biodiesel	Fuel switch to biodiesel
2015				
2016				
2017				
2018	Fuel switch to 50% LNG Add 1 MW biomass	Add 1 MW biomass	Add 1 MW biomass	Battery storage Add 2 MW PV
2019				
2020				
2021		Fuel switch to 50% LNG		
2022				
2023				
2024				
2025				
2026				
2027				
2028				
2029				
2030				
2031				
2032				
2033				
Total Cost	$164,620	$166,235	$107,155	$107,707
Planning Rank	3	4	1	2

Table 19-14. Lanai Preferred, Contingency, Parallel, and Secondary Resource Plans: Stuck in the Middle

	Preferred Plan	**Contingency**	**Parallel**	**Secondary**
Name	**ML-1**	**ML-2**	**ML-3**	**ML-4**
Plan	LNG short-term, biomass	LNG long-term, biomass	100% renewable, biomass, biodiesel	100% renewable, PV, battery, biodiesel
Resources Available	600 kW Wind: 2018 750 kW Wave: 2019 1.0 MW PV: 2018 1.0 MW Biomass: 2018	600 kW Wind: 2018 750 kW Wave: 2019 1.0 MW PV: 2018 1.0 MW Biomass: 2018	600 kW Wind: 2018 750 kW Wave: 2019 1.0 MW PV: 2018 1.0 MW Biomass: 2018	600 kW Wind: 2018 750 kW Wave: 2019 1.0 MW PV: 2018 1.0 MW Biomass: 2018
2014			Fuel switch to biodiesel	Fuel switch to biodiesel
2015				
2016				
2017				
2018	Fuel switch to 50% LNG			Battery storage
	Add 2 MW biomass	Add 2 MW biomass	Add 2 MW biomass	Add 4 MW PV
2019				
2020				
2021		Fuel switch to 50% LNG		
2022				
2023				
2024				
2025				
2026				
2027				
2028				
2029				
2030				
2031				
2032				
2033				
Total Cost	$140,095	$140,677	$153,070	$155,716
Planning Rank	1	2	3	4

Table 19-15. Molokai Preferred, Contingency, Parallel, and Secondary Resource Plans: Blazing a Bold Frontier

	Preferred Plan	**Contingency**	**Parallel**	**Secondary Plan**
Name	**MM-1**	**MM-2**	**MM-3**	**MM-4**
Plan	LNG short-term, biomass	LNG long-term, biomass	100% renewable, biomass, biodiesel	100% renewable, PV, battery, biodiesel
Resources Available	600 kW Wind: 2018 750 kW Wave: 2019 1.0 MW PV: 2018 1.0 MW Biomass: 2018	600 kW Wind: 2018 750 kW Wave: 2019 1.0 MW PV: 2018 1.0 MW Biomass: 2018	600 kW Wind: 2018 750 kW Wave: 2019 1.0 MW PV: 2018 1.0 MW Biomass: 2018	600 kW Wind: 2018 750 kW Wave: 2019 1.0 MW PV: 2018 1.0 MW Biomass: 2018
2014			Fuel switch to biodiesel	Fuel switch to biodiesel
2015				
2016				
2017				
2018	Fuel switch to 50% LNG Add 1 MW biomass	Add 1 MW biomass	Add 1 MW biomass	Battery storage Add 1 MW PV
2019				
2020				
2021		Fuel switch to 50% LNG		
2022				
2023				
2024				
2025				
2026				
2027				
2028				
2029				
2030				
2031				
2032				
2033				
Total Cost	$159,858	$164,439	$105,477	$108,157
Planning Rank	3	4	1	2

Table 19-16. Molokai Preferred, Contingency, Parallel, and Secondary Resource Plans: Stuck in the Middle

	Preferred Plan	Contingency	Parallel	Secondary Plan
Name	**MM-1**	**MM-2**	**MM-3**	**MM-4**
Plan	LNG short-term, biomass	LNG long-term, biomass	100% renewable, biomass, biodiesel	100% renewable, PV, battery, biodiesel
Resources Available	600 kW Wind: 2018 750 kW Wave: 2019 1.0 MW PV: 2018 1.0 MW Biomass: 2018	600 kW Wind: 2018 750 kW Wave: 2019 1.0 MW PV: 2018 1.0 MW Biomass: 2018	600 kW Wind: 2018 750 kW Wave: 2019 1.0 MW PV: 2018 1.0 MW Biomass: 2018	600 kW Wind: 2018 750 kW Wave: 2019 1.0 MW PV: 2018 1.0 MW Biomass: 2018
2014			Fuel switch to biodiesel	Fuel switch to biodiesel
2015				
2016				
2017				
2018	Fuel switch to 50% LNG			Battery storage
	Add 3 MW biomass	Add 3 MW biomass	Add 3 MW biomass	Add 7 MW PV
2019				
2020				
2021		Fuel switch to 50% LNG		
2022				
2023				
2024				
2025				
2026				
2027				
2028				
2029				
2030				
2031				
2032				
2033				
Total Cost	$137,975	$138,840	$151,902	$166,216
Planning Rank	1	2	3	4

Reasonable Costs and Rates, and Captive Customer Rate Impacts

Reasonable cost is an important consideration in the IRP process as stated in the IRP framework goal:

> The goal of integrated resource planning is to develop an Action Plan that governs how the utility will meet energy objectives and customer energy needs consistent with state energy policies and goals, while providing safe and reliable utility service at *reasonable cost*, through the development of Resource Plans and Scenarios of possible futures that provide a broader long-term perspective. [emphasis added]

The Commission also emphasized reasonable cost in Docket Number 2012-0036, Order 30534: Identifying Issues and Questions for Hawaiian Electric Companies' Integrated Resource Planning Process:

> Whether the Action Plan and IRP Report result in affordable electric utility services. Reasonable cost is an important objective for resource planning identified in the statement of the goal of Integrated Resource Planning. The affordability of utility-provided energy services is a primary concern and objective of the commission, especially in light of the need for timely implementation of statutory standards and goals and the need to maintain reliable energy service. Among any other possible measures of the achievement of this objective, the Hawaiian Electric Companies' planning analysis shall include meaningful measures of the rate impacts of the Resource Plans and Action Plan evaluated in accordance with the planning scenarios, forecasts, and sensitivity analyses. The Hawaiian Electric Companies shall determine meaningful measures of rate impacts with input from the Advisory Group.

To address the Commission's focus for the reasonable cost, the Companies utilized the following metrics to compare the relative cost of resource plans.

- Price of electricity in nominal $
- Price of electricity in constant (real 2014) dollars
- Average residential bill in nominal dollars
- Average residential bill in constant (real 2014) dollars
- Nominal residential bill
- Total resource cost

These metrics are graphically shown in Appendix P for each of the eight resource plans for each island (that is, four plans for each of the Blazing a Bold Frontier Scenario and Stuck in the Middle Scenario, which is the Reference Case). In the Advisory Group process, the electricity prices and bills were depicted only in nominal dollars. This final report has added metrics to show the electricity prices and bills in constant dollars.

In comparing bills or costs over a 20-year period, it is appropriate to compare the bills or costs in terms of constant (or "real") dollars. Nominal dollars is a term representing the cost in the year in which the dollars are spent. Constant or real dollars terms represent costs after adjustment for inflation. Constant dollar value is a value expressed in dollars adjusted for purchasing power. For example, $1000 in 2003 is worth $1,236.92 in 2013 when adjusted for inflation using the US Dollar Implicit Price Deflators for Gross Domestic Product.

The general inflation rates assumed for the IRP analyses are identified in *Chapter 6: Four Planning Scenarios*. Based on the 1.87% rate used for the Blazing a Bold Frontier, Stuck in the Middle, and Moved by Passion scenarios, for the 20-year period from 2014 to 2033, the assumed accumulated inflation rate is 44.85%. In constant dollar terms, a $200 bill in 2014 would be equivalent to a $289.71 bill in nominal dollars in 2033.

As described in *Chapter 3: Objectives and Metrics*, the nominal price of electricity was calculated for the residential, commercial, and industrial rate classes. The electricity rate was calculated by dividing the revenue requirements by the sales for each of the rate classes. The nominal residential bill was determined by multiplying the residential electricity rate (in cents/kWh) by a monthly usage of 600 kWh, which the Companies use to represent residential usage. The nominal residential bill also is utilized to represent the typical cost for a customer who purchases all or the majority of his/her electricity from the utility.

The average residential bill takes into consideration that the average customer usage changes annually due to variations in the underlying economic forecast and programs such as energy efficiency DSM and net energy metering. The average residential bill is calculated by dividing the total revenue requirements for the residential sector by the total number of residential customers.

The total resource cost metric is the accumulated present value of the annual revenue requirements over the 20 year planning period.

The total revenue requirement (which includes fuel, purchase power, capital, and operating and maintenance costs) is the basis for calculating all of the metrics above. A significant portion of the total revenue requirement is provided by the Strategist model which projects future costs for fuel, generating unit capital, and production operations and maintenance. The remainder of the total revenue requirements that were added to the model costs fall into two categories: 1) total revenue requirements for the company from the most recent rate case minus fuel, purchase power, and production O&M, which are costs captured by the Strategist model, l, and 2) future non-generation related major projects. The future major projects are not related to the installation of new generating units and include costs such as future fuel infrastructure, retirement and deactivation of existing generation, future environmental controls, and future transmission and distribution.

Preliminary estimates of the major cost adders were assumed and used to develop total resource cost estimates and rate impacts of the various 20 year resource plans (Table 8-4. Resource Plan Cost Assumptions on page 19). Not included in the preliminary estimates of resource plan costs were major project costs such as the Kahe PV and Telecom. However, these costs were later incorporated into the Action Plan rates and bills calculations. The IRP rates and bills calculations do not include non-IRP related costs such as EAM/ERP, customer service, and facilities.

Rates and bills were estimated for the Preferred, Contingency, Parallel, and Secondary plans under the Blazing a Bold Frontier and Stuck in the Middle scenarios. These estimates do *not* provide an absolute projection of rates but instead are planning forecasts that provide relative comparisons of future rates under certain assumptions. The uncertainties with many of the variables used to develop the rate almost certainly mean that the actual rates will be different from these estimates in the future. The estimates assume perfect overnight ratemaking and full cost recovery of projected costs, constant O&M escalation, and use the fuel price forecasts whose actual values and timing will affect the actual rates in the future.

Notwithstanding the limitations of this analysis, these rate estimates were used to evaluate the customer impacts and customer by-pass potential.

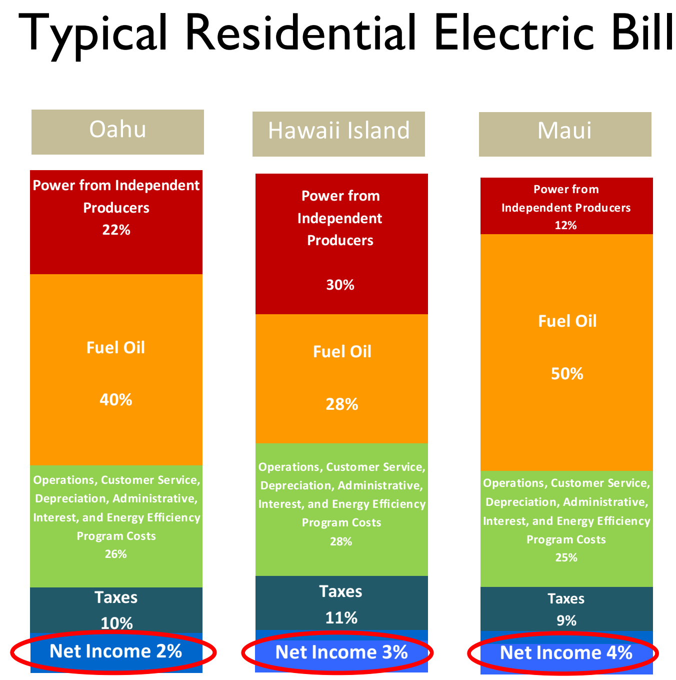
Stabilizing and lowering costs to customers is a critical goal for the Hawaiian Electric Companies. High energy costs, including electricity bills, are a tremendous burden for Hawaii's families and businesses.

Although discussions about resource options tend to focus on the generation costs, it should be noted that the total price customers pay reflects not only the cost of generating (or purchasing) the electricity, but also the costs of transmitting and delivering that energy, billing and processing service requests, acquiring, operating, maintaining and replacing the infrastructure that is necessary to ensure safe and reliable service, the substantial amounts of federal, state and county taxes paid by the Companies, compliance with environmental and other regulatory standards and mandates, and other costs for administration of operations that provide service to more than 450,000 customers.

However, by far, the biggest drivers of costs to customers are fuel and fuel-related purchased power costs, contributing to more than 50% of a typical bill.

For example, the breakdowns of an electric bill on Oahu, Hawaii and Maui as of January 2013:

Figure 19-2. Typical Residential Electric Bill (as of January 2013)



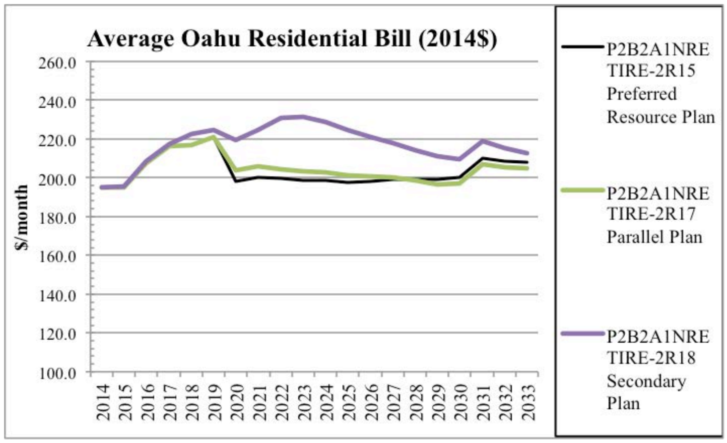
As noted in the Focus on Customer section, a core priority in the action plans for all three Hawaiian Electric Companies is to provide their customers with better information and tools to help them control their energy costs and to responsibly facilitate the ability of customers to generate their own power, likely through photovoltaic systems.

Overall usage has been declining for many years and is expected to continue to decline with the successful implementation of these clean energy strategies. As customers gain greater control over their usage, this will help mitigate the overall cost to them (that is, their bill) and reduce that cost relative to what it would have been if the utilities maintained dependency on oil as the primary fuel.

There will be a growing number of customers who will be able to utilize the options and tools, as well as available incentives such as tax credits, to lower their usage and costs via energy efficiency and self-generation. However, as highlighted in the Fairness section, a smaller remaining base of customers will be left to pay for the fixed capital and operational non-energy costs of running the system. The graphs below reflect the blending of bill impacts for these two groups of customers.

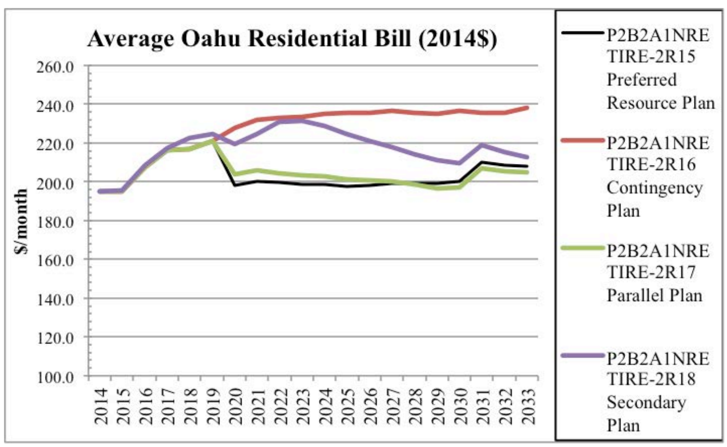
Figure 19-3 shows a hypothetical average residential Oahu bill in constant (2014) dollars under the preferred, parallel and secondary plans:

Figure 19-3. Average Oahu Residential Bill: Preferred, Parallel, and Secondary Plans



However, it is also important to view these bills relative to the higher levels they might be if the primary energy source in the future remains imported oil (contingency plan). This is depicted in Figure 19-4.

Figure 19-4. Average Oahu Residential Bill: Contingency Plan



As a State, we must evaluate the cost to customers and the impact on our State's economy, as well as the benefit of reducing Hawaii's dependency on imported oil through State clean energy policies. The discussion must also address policies that impact fairness for all customers and other policies that contribute to higher energy costs for customers.

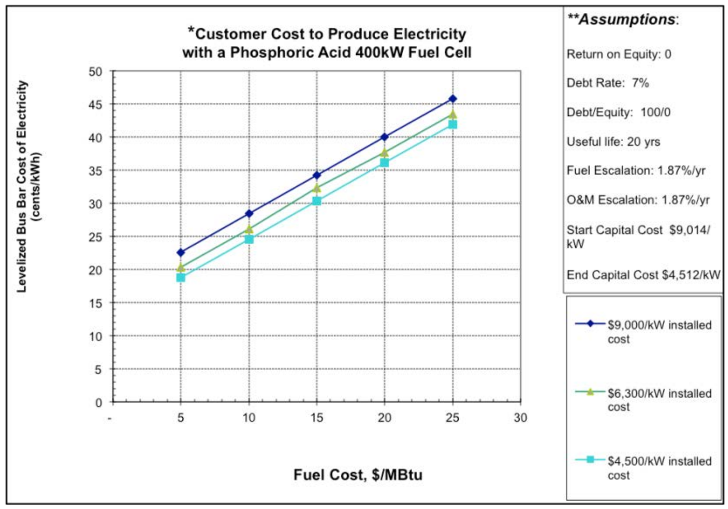
Self-generation Potential of Fuel Cells

The availability of LNG in Hawaii could lead to the ability of the commercial sector to self-generate a portion of their electricity using fuel cells and/or PV. Provided that the distribution of natural gas is available to the user, customers could use fuel cells which would either be fueled directly using the natural gas or from hydrogen reformed from natural gas and stored.

To assess the fuel cell self-generation potential, the cost to own a fuel cell was estimated assuming 100% debt financing at 7% over 20 years. The performance of the fuel cell was assumed to be that of the 400 kW PureCell unit which was developed as part of the supply-side resource options (see *Appendix K: Supply-Side Resource Assessment*).

Figure 19-5 shows the cost to produce electricity using the commercially available fuel cell from ClearEdge Power against various natural gas fuel costs.

Figure 19-5. Customer's Cost to Produce Electricity Using Fuel Cell and Natural Gas



Fuel costs are directly proportional to the cost of electricity as well as the cost to install the fuel cell.

The cost of retail gas is unknown at this time, but it is likely that customers would pay a premium above the bulk fuel cost that Hawaiian Electric estimates would be available for its use (Table 19-17).

Table 19-17. HECO Liquefied Natural Gas Forecast Data

$/MMBtu	HECO	
Year	*Reference*	*High*
2013	n/a	n/a
2014	n/a	n/a
2015	$13.70	$21.11
2016	$14.40	$21.53
2017	$14.60	$22.12
2018	$15.00	$22.75
2019	$15.20	$23.40
2020	$15.50	$24.09
2021	$15.70	$24.82
2022	$16.20	$25.60
2023	$16.60	$26.42
2024	$16.90	$27.27
2025	$17.20	$28.16
2026	$17.60	$29.08
2027	$17.90	$30.04
2028	$18.20	$31.04
2029	$18.50	$32.09
2030	$18.90	$33.18
2031	$24.50	$39.51
2032	$24.90	$40.71
2033	$25.40	$41.96

Several cost curves are provided that reflect the various fuel cell cost estimates. These cost curves can be used to compare to estimates of the future costs of electricity to determine whether customers would consider fuel cells base on “first-cut” economics. If the cost of natural gas fuel is $21/MMBtu (approximately $5/MMBtu higher than Hawaiian Electric’s estimated cost in 2021), then a $9,000/kW fuel cell installation could produce electricity at approximately 41¢/kWh while a $4,500/kW installation would produce it at 37¢/kWh.

These self-generation cost estimates would not be competitive to the approximately 33¢/kWh commercial customer’s rates for Hawaiian Electric’s Preferred resource plan under Stuck in the Middle in 2021 (See Appendix P), and therefore, customer to by-pass the utility would not occur for this scenario.

The low-cost installation may, however, be competitive with the approximately 38¢/kWh estimated rate for the Contingency Resource Plan in 2021. The cost of gas would need to be about $16/MMBtu and the installation costs would need to be $4,500/kW for self-generation to be cost competitive without incentives. It would cost an additional $3/MMBtu to transport LNG to the neighbor islands from a bulk facility located on Oahu so the cost of natural gas would be $24/MMBtu, then a $9,000/kW installation would produce electricity at approximately 45¢/kWh while a $4,500/kW installation would produce it at 41¢/kWh.

These self-generation cost estimates would be competitive with the approximately 49¢/kWh commercial customer's rates (See Appendix P) for HELCO's Preferred resource plan under Stuck in the Middle in 2021.

For MECO, these self-generation cost estimates would be competitive with the approximately 55¢/kWh commercial customer's rates (See Appendix P) for MECO's Preferred resource plan under Stuck in the Middle in 2021.

For the residential market, Figure 19-6 and Figure 19-7 show the monthly energy transaction cost for three residential sector customers using the Hawaiian Electric Company's residential rate data for the Preferred plan in Stuck in the Middle.

Figure 19-6. Cost of Customer Energy Cost vs. Energy Cost of Self-Generation Customers in 2025

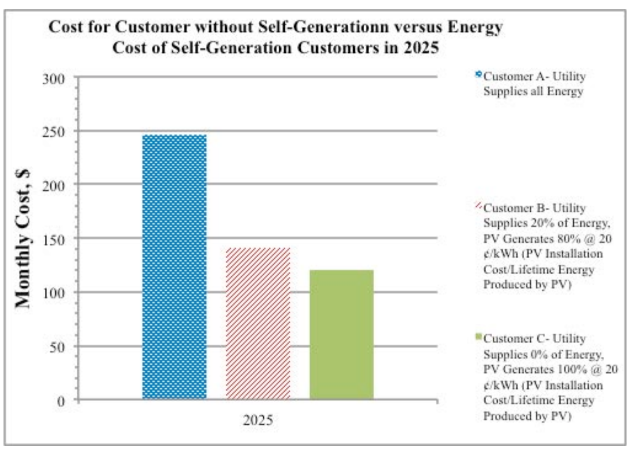
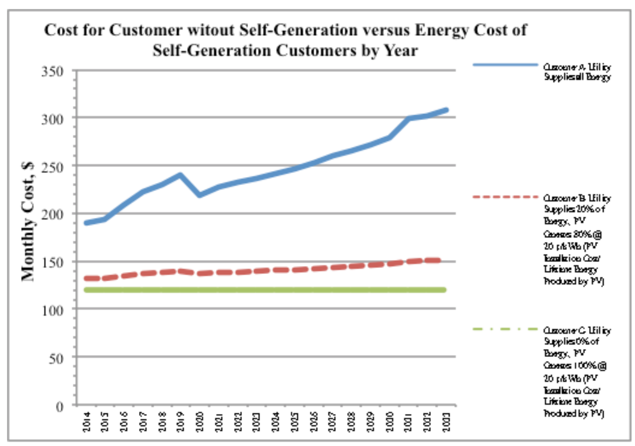


Figure 19-7. Cost of Customer Energy Cost vs. Energy Cost of Self-Generation Customers by Year



The customers who produce all or part of their electricity needs using PV that costs 20 ¢/kWh (PV Installation Cost/Lifetime Energy Produced by PV) have lower monthly electrical energy costs compared to customers who do not have PV and need to get all of their electricity from the utility. Comparisons for HELCO and MECO would produce the same relative results. These charts reconfirm what has already been occurring and reflected by the large number of customers who have installed rooftop PV, and who have taken advantage of the incentives and net energy metering

(NEM) program. The loss of sales from the NEM is reflected in the sales forecasts for each scenario.

The Companies also analyzed the case where after implementation of the major action items for its Preferred plan, it would experience a large decrease in sales beyond its control due to factors such as large customer exit, self-generation technology breakthrough, natural disasters, or any other unexpected factor. Figure 19-8 shows the impact of this event and shows the sales forecast of a case with a 10% loss of sales in 2021 and 1% per year thereafter. This large decrease in sales would result in large fixed utility costs spread over a smaller sales base.

Figure 19-8. Sales Forecast Comparison of Stuck in the Middle Baseline Forecast Versus Forecast with Large Decrease in Sales for Hawaiian Electric

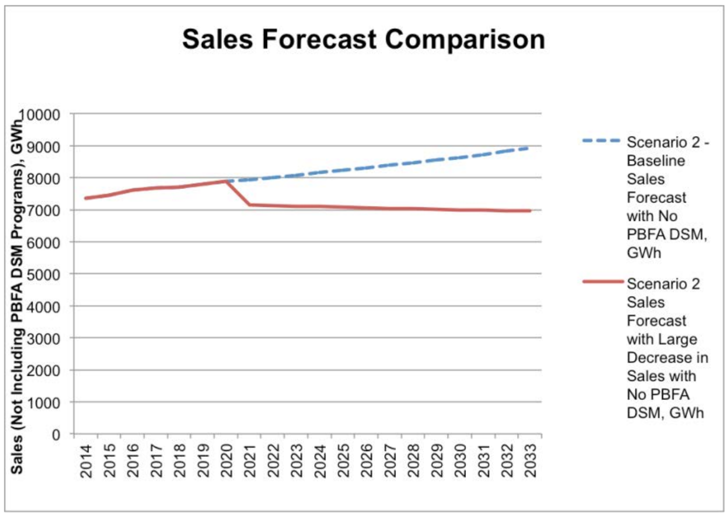
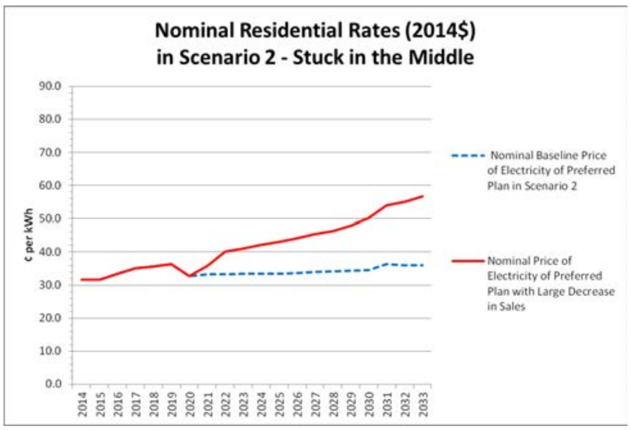


Figure 19-9 shows this impact for residential and commercial rate classes. If this case were to occur, it would lead to larger rate increases compared to the Preferred Resource Plan and naturally more customer self-generation and utility-by pass potential. With the large sales decrease, in 2022 commercial rates would be approximately 40¢/kWh which would bring the 41¢/kWh $9,000/kW installation closer to being cost completive and the 37¢/kWh $4,500/kW installation a cost competitive option for customers to self-generate.

Figure 19-9. HECO Residential and Commercial Constant (Real 2014) Rates of the Preferred Plan with High Decrease in Sales in Stuck in the Middle



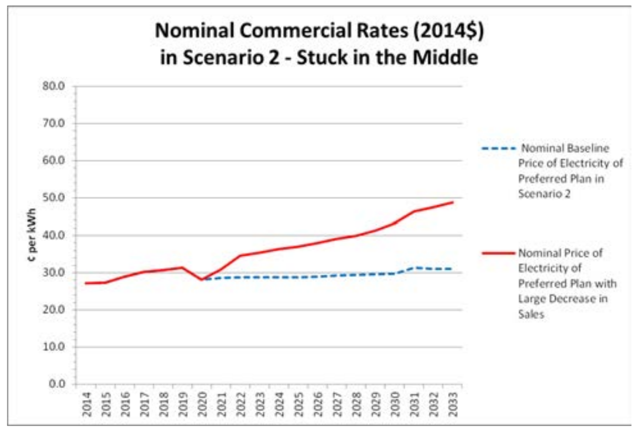
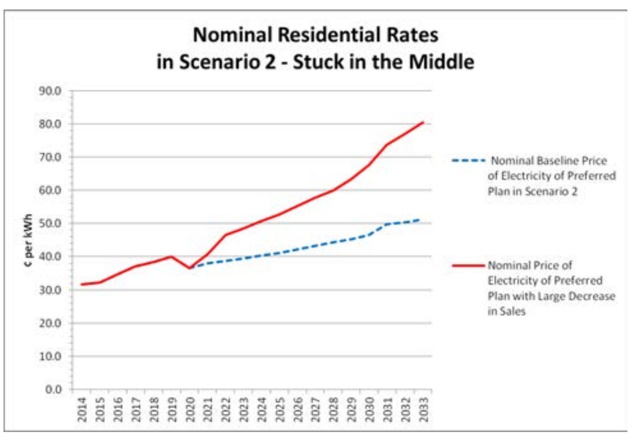
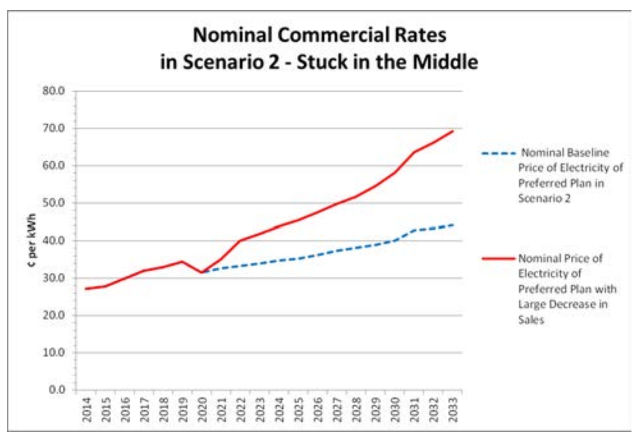


Figure 19-10. HECO Residential and Commercial Nominal Rates of the Preferred Plan with High Decrease in Sales in Stuck in the Middle





Consolidated RPS Percentage of the Preferred Plans

Based on the renewable energy production and the sales from the Hawaiian Electric, HELCO, and MECO Preferred Plan runs, the consolidated renewable portfolio standards percentage was calculated for each year of the planning period. Figure 19-11 and Figure 19-12 reflect the consolidated RPS percentage using the sales from the Blazing a Bold Frontier and Stuck in the Middle scenarios. This projection assumes that all of the projects shown in the Preferred Plans are developed and placed into service. It is the companies' objective to meet and exceed the RPS goal.

Figure 19-11. Consolidated RPS Sales Percentage Preferred Plans: Blazing a Bold Frontier

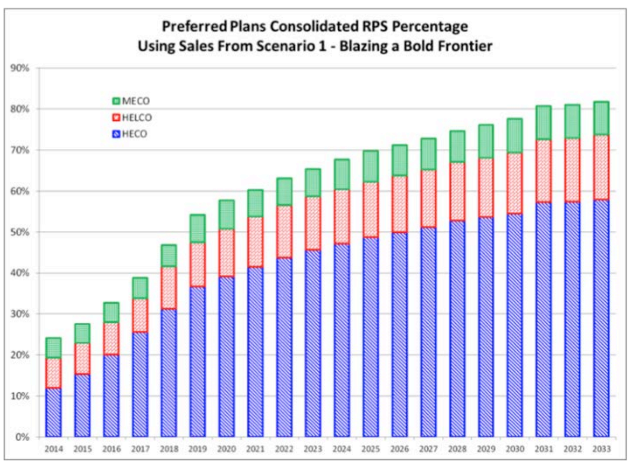
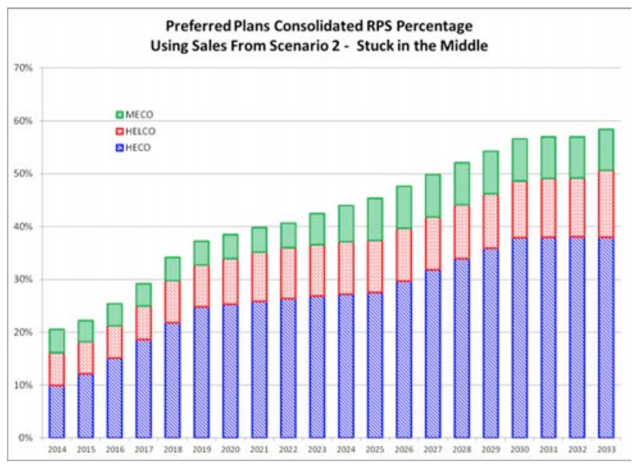


Figure 19-12. Consolidated RPS Sales Percentage Preferred Plans: Stuck in the Middle



Action Plan Rates and Bills Analysis – Hawaiian Electric

In Appendix O and P, the Companies presented costs for the resource plans based upon the Strategist model results plus an adder for costs not captured in the model. Subsequent to this analysis, updated costs were developed in conjunction with the Action Plan. A more focused rates and bills analysis for the Action Plan period (2014–2018) was performed using the Preferred Resource Plan. The table below presents the "outside the model" costs used in the Action Plan rates and bills analysis.

Table 19-18. Hawaiian Electric Action Plan Cost Assumption (Millions)

Project	2014	2015	2016	2017	2018
Deactivation of Honolulu 8 & 9	$2.00	$1.00	$1.00	$1.00	$1.00
Deactivation of Waiau 3 & 4	–	–	–	$2.00	$1.00
Diesel Conversion: Total	$7.10	$36.10	$4.70	–	–
Kalaeloa Pipeline	$3.00	$14.50	$11.70	–	–
CIP Steam Turbine 1 Project	$1.00	$1.00	$10.00	$50.00	$88.00
Operational Flexibility: Total	$3.14	$15.39	$21.29	$30.56	$5.97
Photovoltaic Projects	$3.63	$4.41	$0.08	–	–
Other Renewables	$1.35	–	–	–	–
Kahe Utility-Scale Photovoltaic (PV) System	$1.00	$44.00	–	–	–
Schofield Generating Station	$1.45	$12.04	$84.84	$79.87	$5.00
Arc Flash Mitigation	$2.12	$2.17	$2.21	$2.25	$2.30
Substation Lighting	$0.22	$0.24	$0.27	$0.29	–
Transmission	$68.56	$102.95	$148.41	$130.82	$39.96
Sub-transmission	$13.14	$15.17	$14.77	$11.99	$10.51
Distribution	$60.21	$110.89	$121.18	$156.33	$148.83
Reliability	$4.70	$5.98	$4.96	$4.89	$4.89
Distribution Automation	$5.67	$9.60	$9.56	$21.04	$3.32
Central Baseyard & Warehouse	$5.71	$23.68	$43.34	$34.24	$0.29
Operational Improvements	$4.09	$5.46	$3.81	$1.99	$2.20
Telecom: Total	$5.92	$15.72	$15.72	$12.45	$12.45
AMI (HECO): Capital	$0.37	$0.35	$10.49	$39.02	$40.19
Utility-owned BESS project	$0.36	$4.50	$29.16	$0.06	–
Base Capital (Production)	$41.60	$30.78	$44.65	$47.50	$45.00

The costs above were used in the calculation of the Action Plan rates and bills analysis.

The price of electricity for residential customers, based on the Preferred Resource Plan, is shown below:

Figure 19-13. Hawaiian Electric Price of Electricity in Constant (Real 2014) Dollars

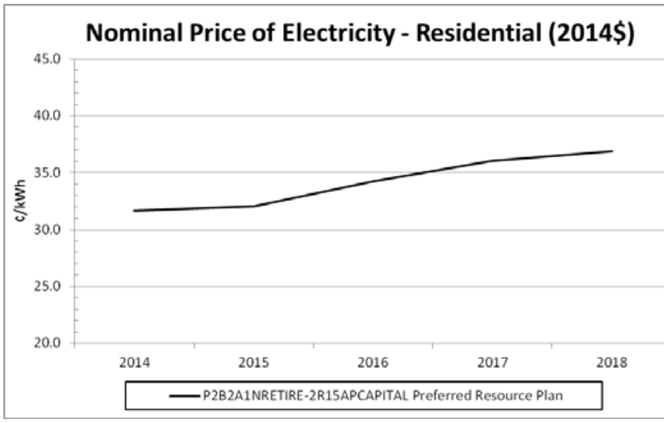
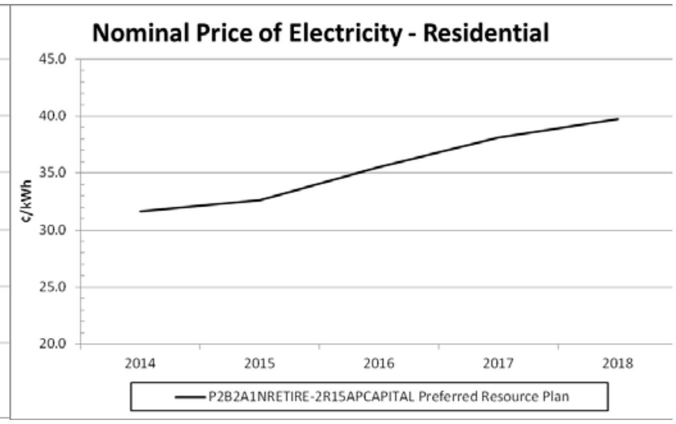


Figure 19-14. Hawaiian Electric Price of Electricity in Nominal Dollars



The price of electricity for commercial customers, based on the Preferred Resource Plan, is shown below:

Figure 19-15. Hawaiian Electric Price of Electricity in Constant (Real 2014) Dollars

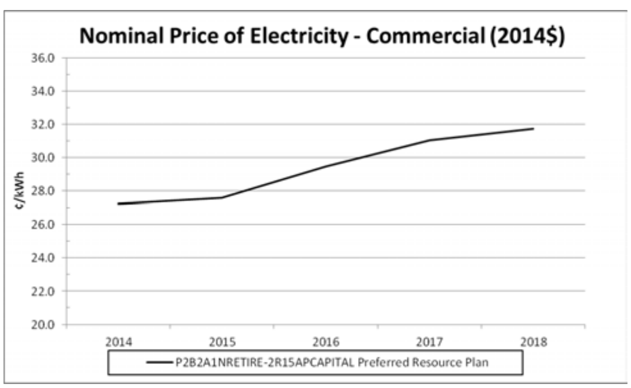
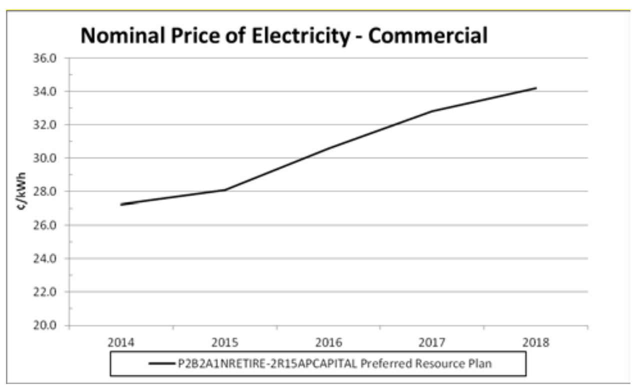


Figure 19-16. Hawaiian Electric Price of Electricity in Nominal Dollars



The price of electricity for industrial customers, based on the Preferred Resource Plan, is shown below:

Figure 19-17. Hawaiian Electric Price of Electricity in Constant (Real 2014) Dollars

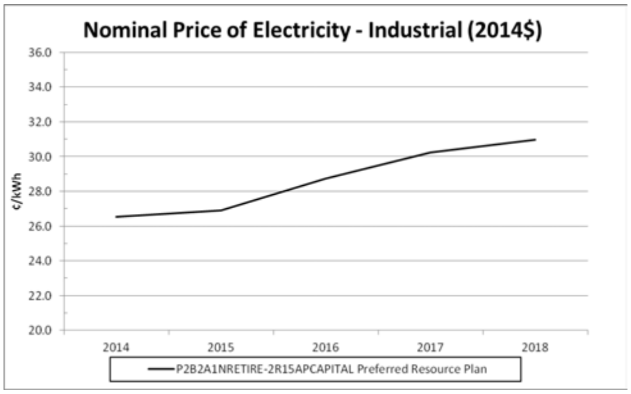
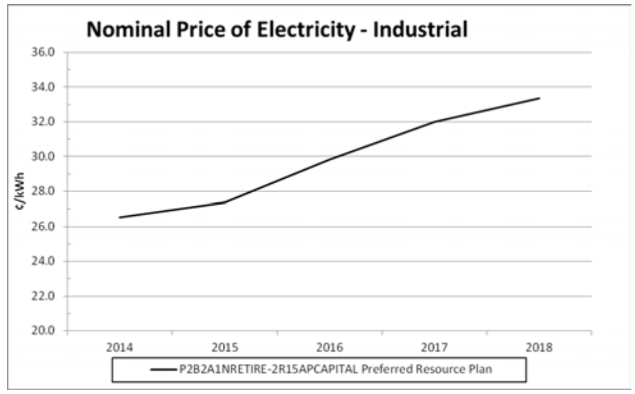


Figure 19-18. Hawaiian Electric Price of Electricity in Nominal Dollars



The average residential bill in nominal dollars per month and in constant (real) dollars to year 2014 is shown below.

Figure 19-19. Hawaiian Electric Average Residential Bill in Constant (Real 2014) Dollars

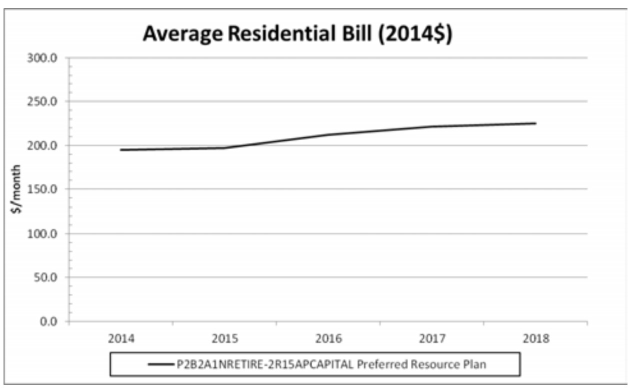
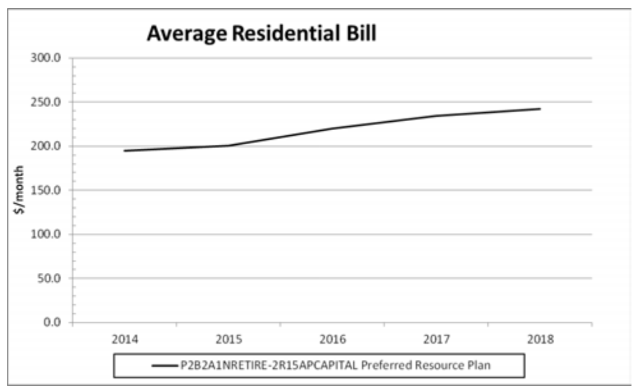


Figure 19-20. Hawaiian Electric Average Residential Bill in Nominal Dollars



Action Plan Rates and Bills Analysis — HELCO

In Appendix O and P, the Companies presented costs for the resource plans based upon the Strategist model results plus an adder for costs not captured in the model. See Table 29 for a list of these "outside the model" costs that were included in the 20-year planning period resource plan costs and quantitative metrics. Subsequent to this analysis, updated costs were developed in conjunction with the Action Plan. A more focused rates and bills analysis for the Action Plan period (2014–2018) was performed using the Preferred Resource Plan. The table below presents the "outside the model" costs used in the Action Plan rates and bills analysis.

Table 19-19. HELCO Action Plan Cost Assumption (Millions)

Project	2014	2015	2016	2017	2018
Deactivation of Shipman Units 3 & 4	–	$2.00	$2.00	–	–
Waiau Hydro Repower	–	$0.60	$4.60	$1.50	–
Hill 5 Projects	$0.26	–	–	–	–
Hill 6 Projects	$0.70	–	–	–	–
Puna Steam Projects	$0.63	$0.25	–	–	–
6800 Line Reconstruction	$6.90	$7.50	$3.40	–	–
3300 Line Rebuild	$3.40	$4.50	$5.60	$5.00	–
3400 Line Rebuild	$5.50	$2.60	$2.30	–	–
Telecom: Total	$3.96	$5.92	$6.79	$6.26	$6.48
AMI: Capital	$0.04	$0.07	$2.96	$21.34	$0.32
Base Capital (Production)	$2.56	$2.48	$2.09	$2.27	$2.27
Base Capital (Transmission)	$52.48	$56.58	$47.56	$51.66	$51.66

The costs above were used in the calculation of the Action Plan rates and bills analysis.

The price of electricity for residential customers, based on the Preferred Resource Plan, is shown below:

Figure 19-21. HELCO Price of Electricity in Constant (Real 2014) Dollars

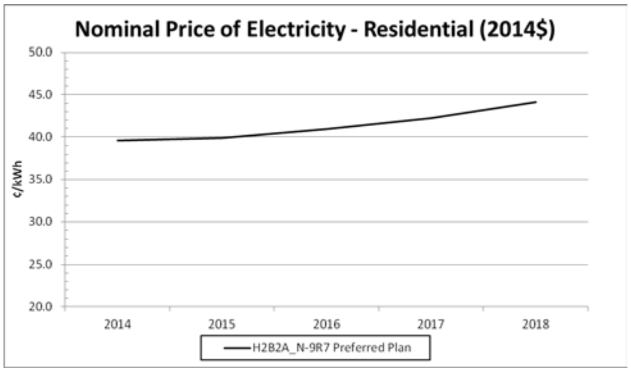
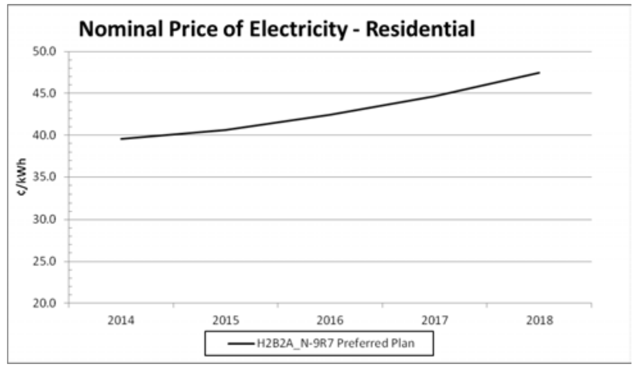


Figure 19-22. HELCO Price of Electricity in Nominal Dollars



The price of electricity for commercial customers, based on the Preferred Resource Plan, is shown below:

Figure 19-23. HELCO Price of Electricity in Constant (Real 2014) Dollars

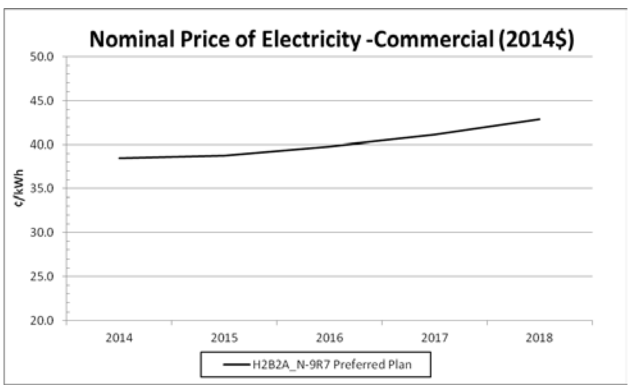
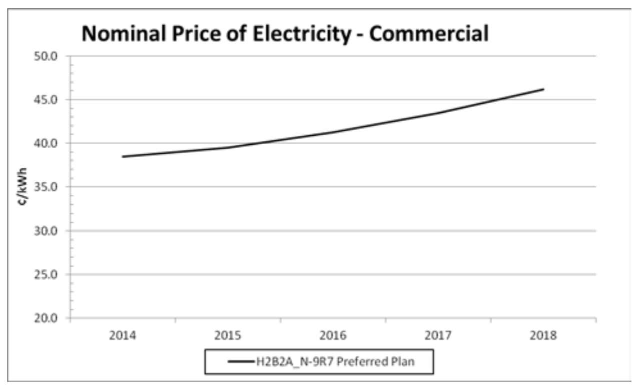


Figure 19-24. HELCO Price of Electricity in Nominal Dollars



The price of electricity for industrial customers, based on the Preferred Resource Plan, is shown below:

Figure 19-25. HELCO Price of Electricity in Constant (Real 2014) Dollars

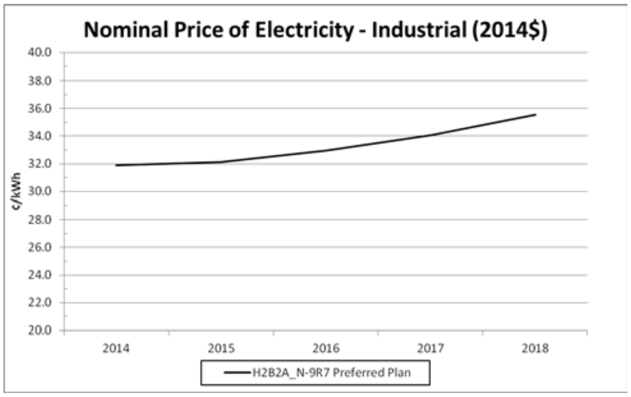
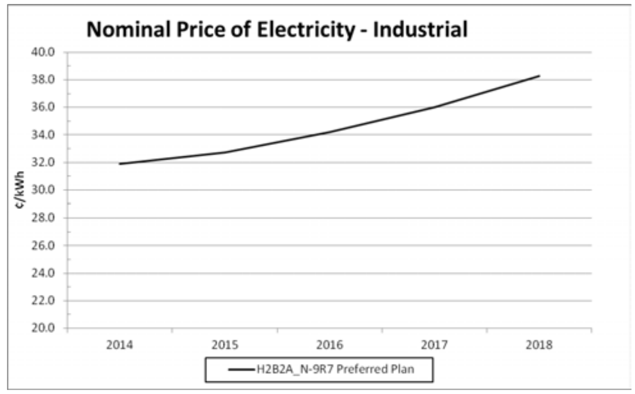


Figure 19-26. HELCO Price of Electricity in Nominal Dollars



The average residential bill in nominal dollars per month and in constant (real) dollars to year 2014 is shown below.

Figure 19-27. HELCO Average Residential Bill in Constant (Real 2014) Dollars

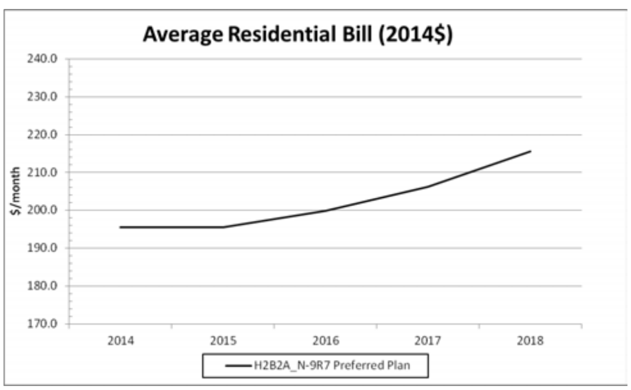
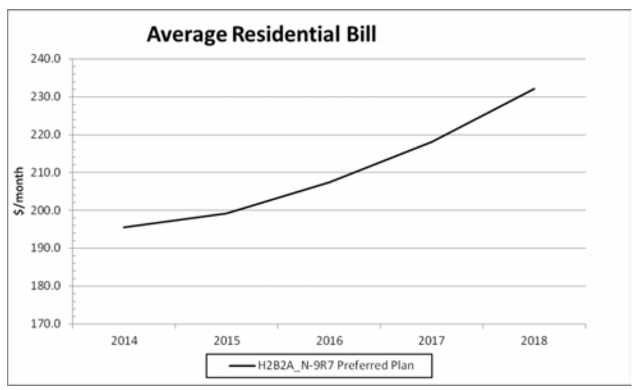


Figure 19-28. HELCO Residential Bill in Nominal Dollars



Action Plan Rates and Bills Analysis: MECO

In Appendix O and P, the Companies presented costs for the resource plans based upon the Strategist model results plus an adder for costs not captured in the model. See Table 29 for a list of these "outside the model" costs that were included in the 20-year planning period resource plan costs and quantitative metrics. Subsequent to this analysis, updated costs were developed in conjunction with the Action Plan. A more focused rates and bills analysis for the Action Plan period (2014–2018) was performed using the Preferred Resource Plan. The table below presents the "outside the model" costs used in the Action Plan rates and bills analysis.

Table 19-20. Maui Action Plan Cost Assumption (Millions)

Project	2014	2015	2016	2017	2018
Kaonoulu substation	$6.50	$7.63	$0.00	$0.00	$0.00
Kamalii substation and MPP-Kamalii 69 kV line	$1.32	$6.05	$13.16	$10.97	$0.01
Waiinu-Kanaha 69 kV line	$1.12	$1.00	$1.49	$11.75	$13.28
Kuihelani substation	$2.90	$7.08	$7.26	$0.00	$0.00
Waena Dispatch Center	$0.00	$0.00	$0.00	$7.00	$0.00
Other T&D	$12.54	$9.93	$8.47	$7.68	$7.14
AMI (Maui) –capital	$0.04	$0.07	$2.41	$16.78	$0.32
Telecom – Total	$0.25	$4.36	$7.77	$5.66	$6.42
Utility-Owned BESS Project	$0.20	$0.30	$6.20	$22.50	$0.52
Tsunami protection	$0.52	$0.10	$6.16	$7.54	$0.00
Base Capital (Production)	$9.43	$12.42	$14.26	$16.79	$16.79
Base Capital (Transmission)	$31.16	$41.04	$47.12	$55.48	$55.48

Table 19-21. Lanai Action Plan Cost Assumption (Thousands)

Project	2014	2015	2016	2017	2018
Miki Basin 7 Modifications	$30.00	$70.00	$20.00	$1,010.00	$0.00
Miki Basin 8 Modifications	$30.00	$70.00	$20.00	$1,010.00	$0.00
Total	$60.00	$140.00	$40.00	$2,020.00	$0.00
Distribution	$450.00	$450.00	$450.00	$450.00	$450.00
AMI-Lanai	$3.00	$1.00	$52.00	$602.00	$0.00
Telecom: Total	$0.00	$0.00	$0.00	$278.00	$0.00

Table 19-22. Molokai Action Plan Cost Assumption (Thousands)

Project	2014	2015	2016	2017	2018
Palaau 7 Modifications	$30.00	$70.00	$20.00	$1,010.00	$0.00
Palaau 8 Modifications	$30.00	$70.00	$20.00	$1,010.00	$0.00
Palaau 9 Modifications	$30.00	$70.00	$20.00	$1,010.00	$0.00
Total	$90.00	$210.00	$60.00	$3,030.00	$0.00
Other T&D	$850.00	$850.00	$850.00	$850.00	$850.00
AMI-Molokai	$6.00	$1.00	$100.00	$1,149.00	$0.00
Telecom: Total	$0.00	$0.00	$0.00	$552.00	$0.00

The costs above were used in the calculation of the Action Plan rates and bills analysis.

The price of electricity for residential customers, based on the Preferred Resource Plan, is shown below:

Figure 19-29. MECO-Maui Price of Electricity in Constant (Real 2014) Dollars

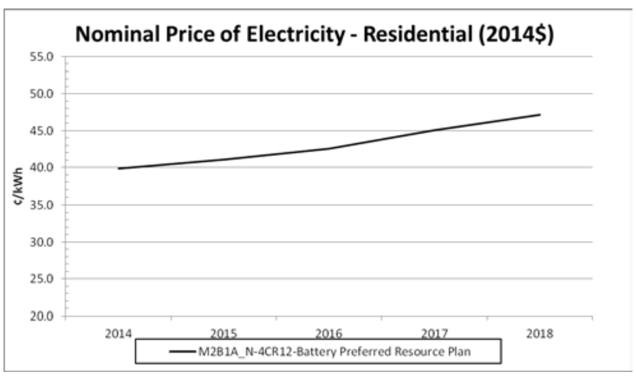
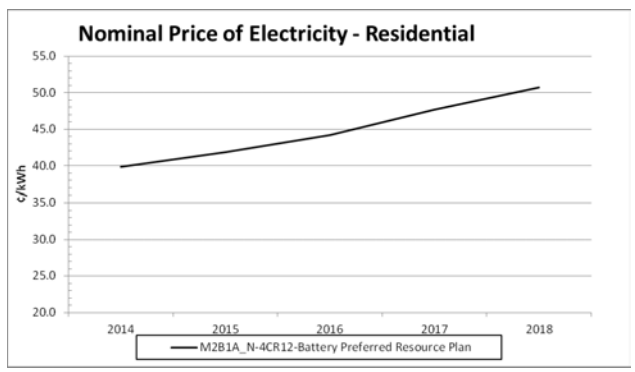


Figure 19-30. MECO- Maui Price of Electricity in Nominal Dollars



The price of electricity for commercial customers, based on the Preferred Resource Plan, is shown below:

Figure 19-31. MECO-Maui Price of Electricity in Constant (Real 2014) Dollars

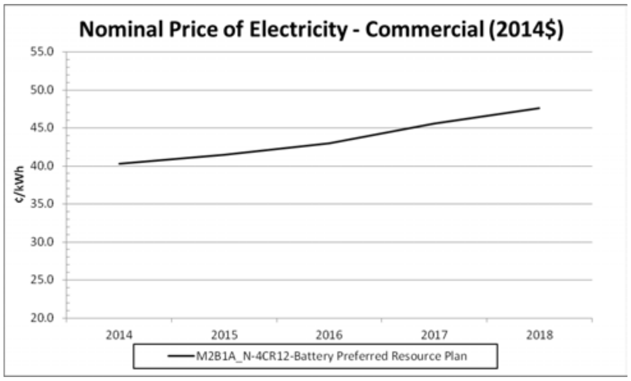
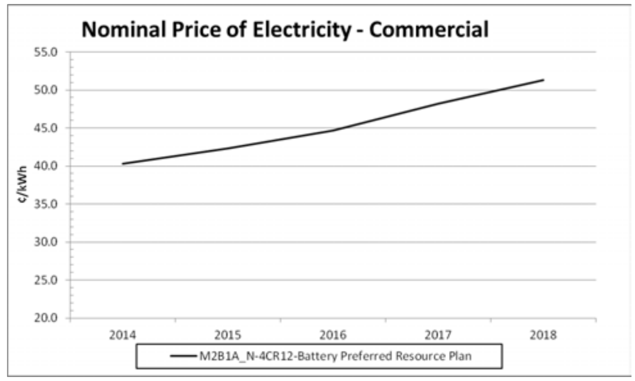


Figure 19-32. MECO-Maui Price of Electricity in Nominal Dollars



The price of electricity for industrial customers, based on the Preferred Resource Plan, is shown below:

Figure 19-33. MECO-Maui Price of Electricity in Constant (Real 2014) Dollars

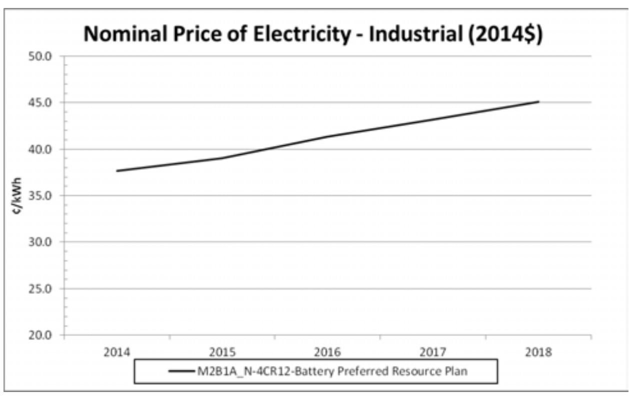
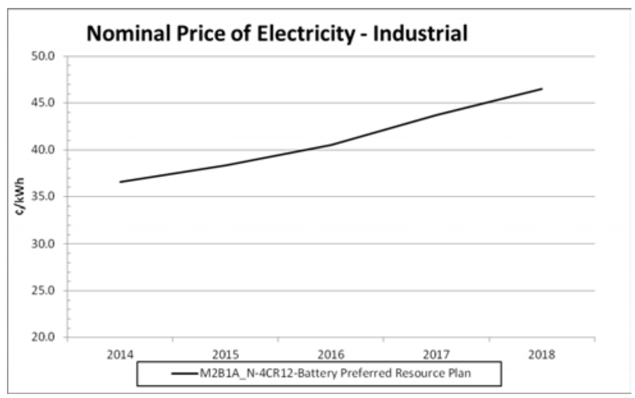


Figure 19-34. MECO-Maui Price of Electricity in Nominal Dollars



The price of electricity for residential customers, based on the Preferred Resource Plan, is shown below:

Figure 19-35. MECO-Lanai Price of Electricity in Constant (Real 2014) Dollars

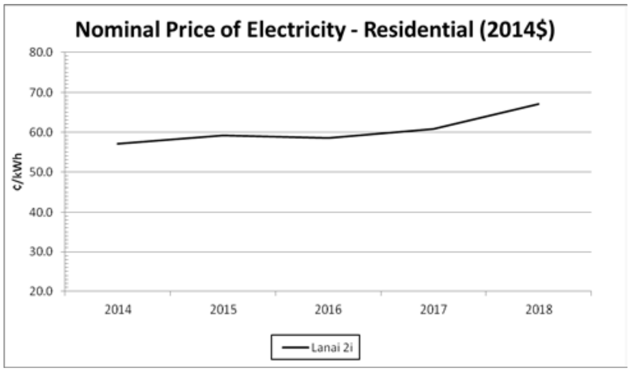
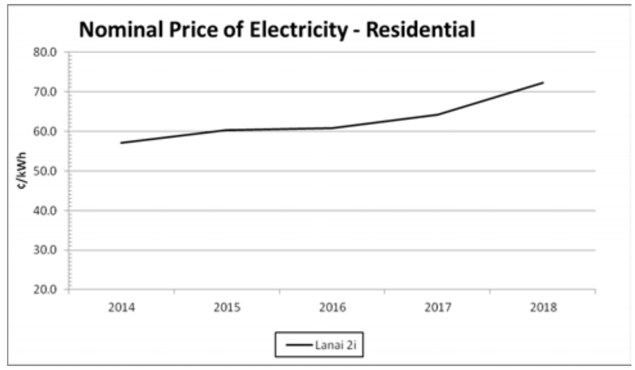


Figure 19-36. MECO- Lanai Price of Electricity in Nominal Dollars



The price of electricity for commercial customers, based on the Preferred Resource Plan, is shown below:

Figure 19-37. MECO-Lanai Price of Electricity in Constant (Real 2014) Dollars

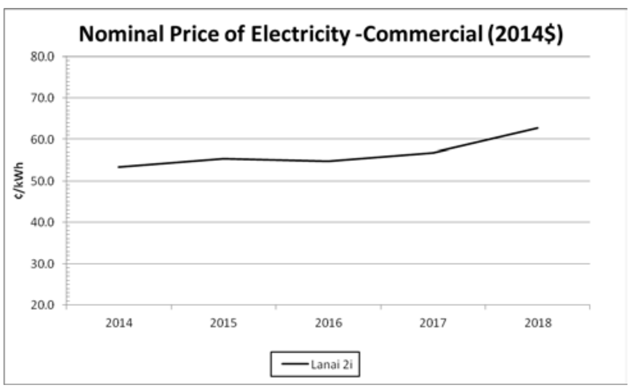
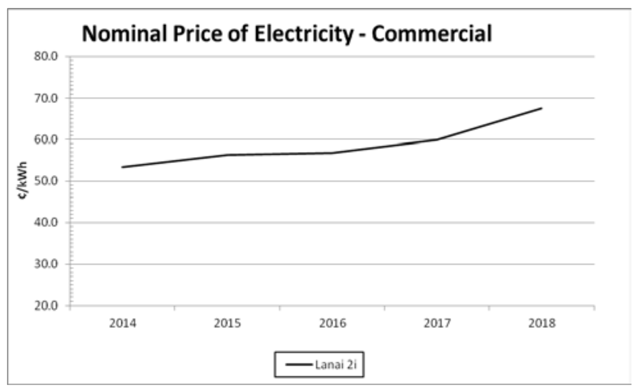


Figure 19-38. MECO-Lanai Price of Electricity in Nominal Dollars



The price of electricity for industrial customers, based on the Preferred Resource Plan, is shown below:

Figure 19-39. MECO-Lanai Price of Electricity in Constant (Real 2014) Dollars

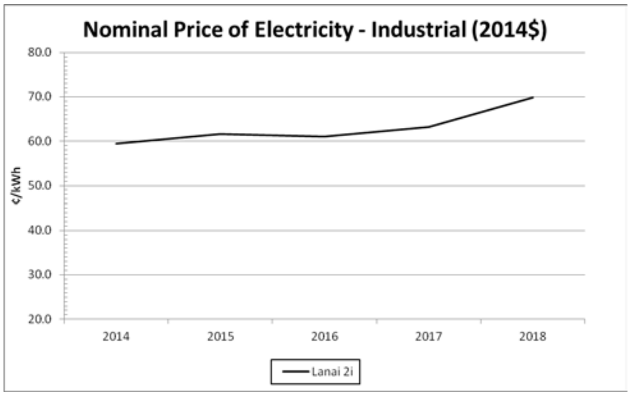
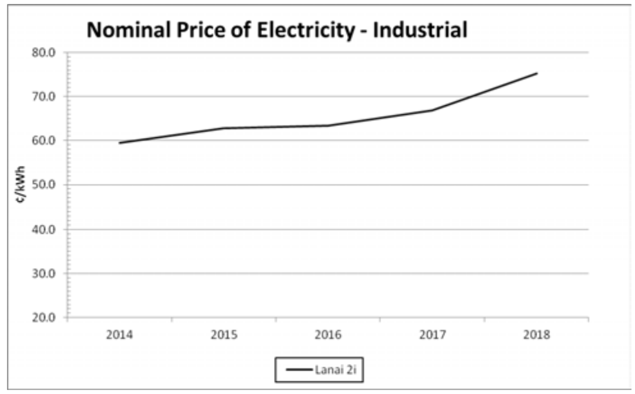


Figure 19-40. MECO-Lanai Price of Electricity in Nominal Dollars



The price of electricity for residential customers, based on the Preferred Resource Plan, is shown below:

Figure 19-41. MECO-Molokai Price of Electricity in Constant (Real 2014) Dollars

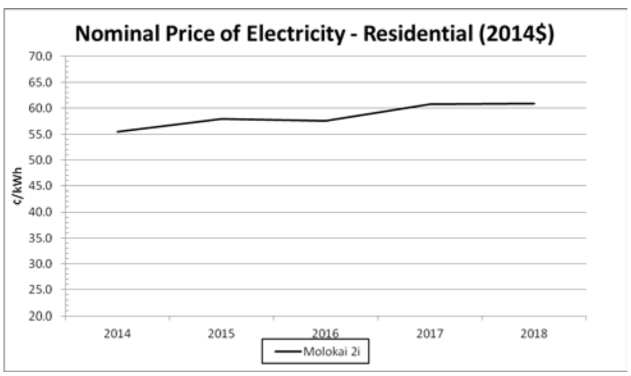
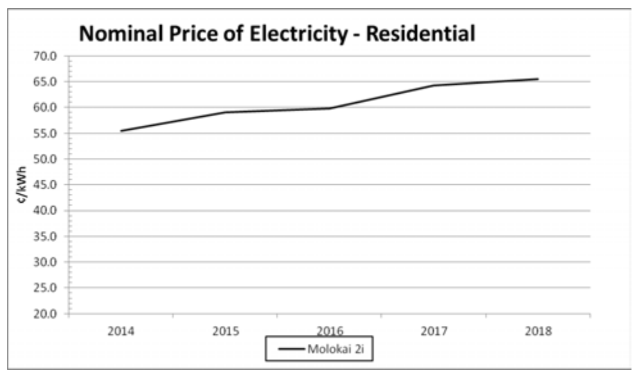


Figure 19-42. MECO- Molokai Price of Electricity in Nominal Dollars



The price of electricity for commercial customers, based on the Preferred Resource Plan, is shown below:

Figure 19-43. MECO-Molokai Price of Electricity in Constant (Real 2014) Dollars

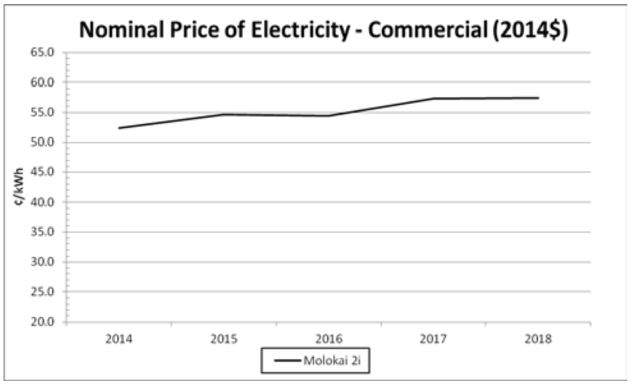
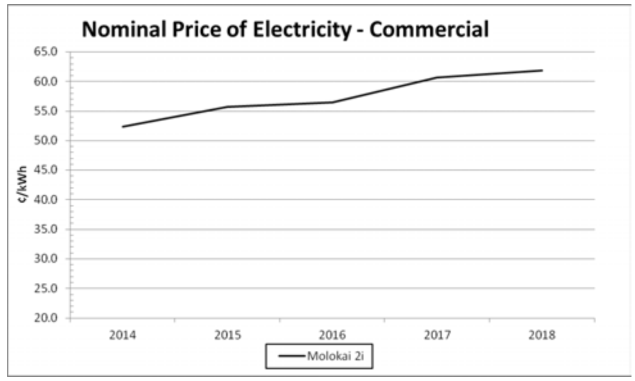


Figure 19-44. MECO-Molokai Price of Electricity in Nominal Dollars



The price of electricity for industrial customers, based on the Preferred Resource Plan, is shown below:

Figure 19-45. MECO-Molokai Price of Electricity in Constant (Real 2014) Dollars

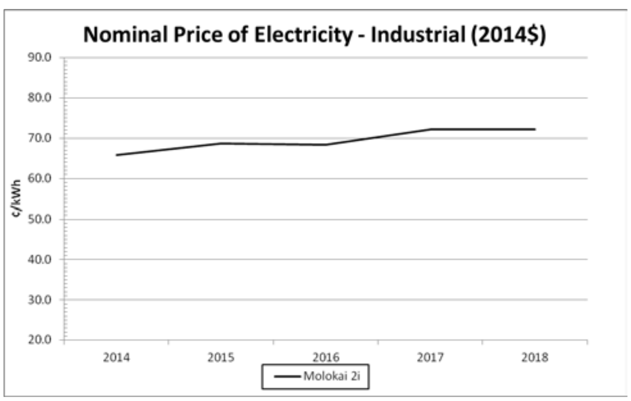
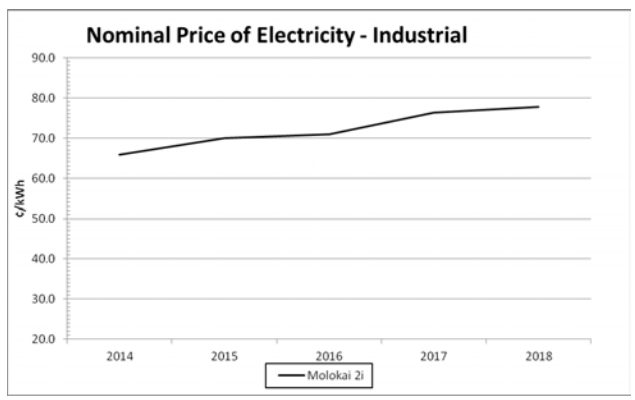


Figure 19-46. MECO-Molokai Price of Electricity in Nominal Dollars



The average residential bill in nominal dollars per month and in constant (real) dollars to year 2014 is shown below.

Figure 19-47. MECO-Maui Average Residential Bill in Constant (Real 2014) Dollars

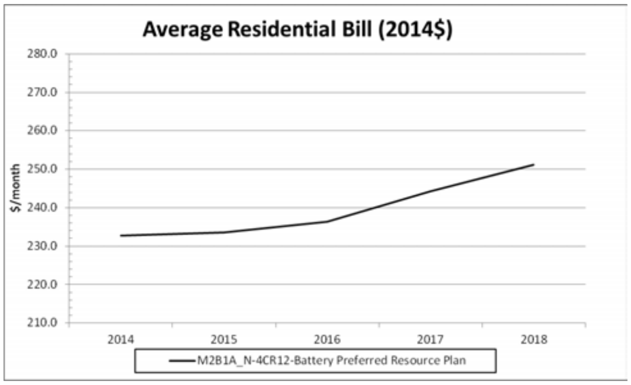
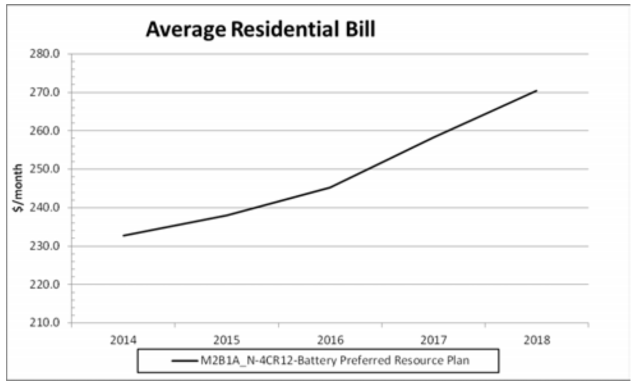


Figure 19-48. MECO-Maui Average Residential Bill in Nominal Dollars



The average residential bill in nominal dollars per month and in constant (real) dollars to year 2014 is shown below.

Figure 19-49. MECO-Lanai Average Residential Bill in Constant (Real 2014) Dollars

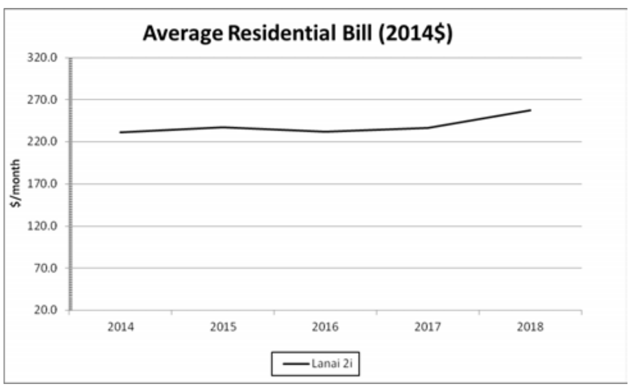
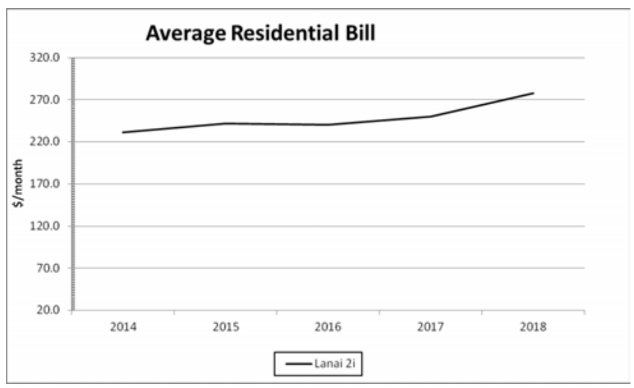


Figure 19-50. MECO-Lanai Average Residential Bill in Nominal Dollars



The average residential bill in nominal dollars per month and in constant (real) dollars to year 2014 is shown below.

Figure 19-51. MECO-Molokai Average Residential Bill in Constant (Real 2014) Dollars

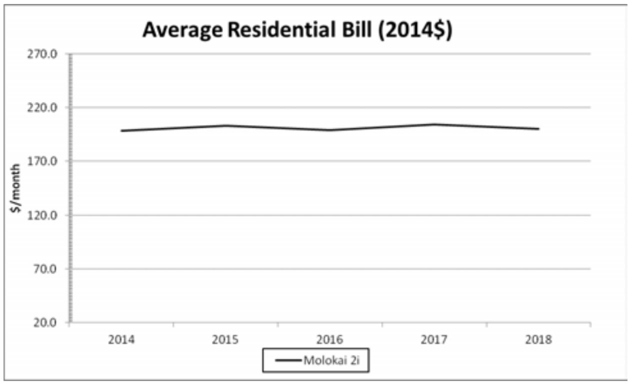
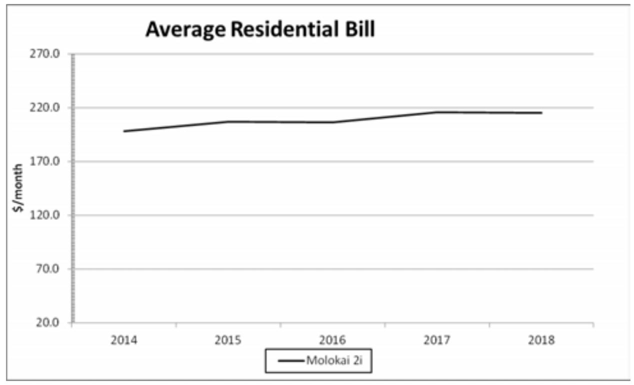


Figure 19-52. MECO-Molokai Average Residential Bill in Nominal Dollars



Chapter 20: Hawaiian Electric Action Plan

The Hawaiian Electric Action Plan details the specific actions to take to meet energy needs, with an accompanying implementation schedule, over the next five years of our twenty year planning cycle. Putting this plan into effect will meet the energy requirements of Oahu, the state of Hawaii's most populated island.

Implementation of the Action Plan

The energy landscape on Oahu is complicated and varied. To best meet the broad array of energy needs, the actions the Companies have developed are equally complex. To best show the interrelation of these actions, the Companies have developed flowcharts that show the interactions between and among these actions.

Implementing one action often affects another action. Understanding the relationship among all of these actions enables the Companies to not only mitigate the downside of taking one action at the expense of another, but also to execute these actions in a way that best meets the current and future energy needs of our customers.

Four Strategic Themes

The Companies have identified future circumstances and developed appropriate actions that can move the Companies toward our goals. These actions are detailed in our Action Plans under four strategic themes:

- Lower customer bills
- Clean energy future
- Modernized grid
- Fairness

The Companies face many challenging issues and uncertainties about a rapidly changing energy environment. Thus, the Companies' IRP report is informative and the Action Plans are clear enough to identify what undertakings (for example, projects, programs, studies) must be done in a structured, proactive manner, while being flexible enough to adapt to an ever-changing future.

Lower Customer Bills

1. Deactivate/Decommission Generation

1.A. Honolulu 8 & 9 and Waiau 3 & 4

Purpose: To deactivate and decommission existing generation.

Scope: To deactivate Honolulu 8 & 9 in 2014 and to deactivate Waiau 3 & 4 in 2016. Deactivating and decommissioning of additional units will be considered as peak load decreases. Deactivating units in lieu of decommissioning units allows for the potential reactivation for emergencies and/or generation shortfalls. At this time, determination of when to switch from deactivation status to decommission status of Honolulu 8 & 9 and Waiau 3 & 4 will be outside of this 5-year Action Plan window. The Companies are estimating an annual savings of up to $8 Million per year (including O&M) for the deactivation of Honolulu 8 & 9 (which is not shown in Table 20-1). The Strategist model accounts for this savings in the Resource Plans.

Table 20-1. HECO Deactivation Project Capital Expenditures and Plant Addition Costs (Millions)

Project	Prior Years	2013	2014	2015	2016	2017	2018	Future Years	Total	In-Service Year
Deactivation of Honolulu 8 & 9	–	–	$2	$1	$1	$1	$1	$5	–	–
Deactivation of Waiau 3 & 4	–	–	–	–	–	$2	$1	$5	–	–

1.B. Deactivate/Decommission additional units as peak load decreases

Scope: Monitor peak load as the future unfolds and deactivate and/or decommission existing generation if capacity is not needed.

1.C. Reactivate generating units if needed for emergencies and/or generation shortfalls

Scope: Monitor peak load and capability of existing generating units as the future unfolds and reactivate generating units if capacity is needed.

2. Lower-Cost Generating Facilities

2.A Complete current Invitation for "Waiver Projects"

Purpose: To lower customer's electric bills in the near-term by seeking qualified utility-scale renewable energy projects on Oahu that developers can quickly place into service at a low cost per kilowatt-hour.

Scope: On February 22, 2013, Hawaiian Electric issued an Invitation for Waivered Projects ("Invitation") stating that it would consider requesting a waiver from the Commission's Competitive Bidding Framework for qualifying low cost renewable energy projects that can be quickly placed into service by the end of 2015.

Hawaiian Electric selected five projects averaging 15.9 cents per kWh on a levelized basis, without the use of Hawaii state tax credits, and on June 18, 2013, filed an Application in Docket No. 2013-0156 requesting waivers from the Framework for Competitive Bidding for the five selected projects ("Application for Waivers"). The Application for Waivers is currently pending before the Commission. If the Commission approves the waiver request, Hawaiian Electric will negotiate and execute power purchase agreements and file them for Commission approval.

Hawaiian Electric issued a pricing refresh opportunity to developers who submitted proposals in response to the Invitation but who were not selected for inclusion in the initial Application for Waivers. It is Hawaiian Electric's intent that this pricing refresh opportunity will further lower the energy market price. If Hawaiian Electric receives refreshed proposals that meet the threshold criteria stated in the Invitation and the refreshed pricing criteria, Hawaiian Electric will further evaluate such proposals and may submit a supplemental waiver application for one or more additional projects.

2.B. Competitive Bid for more efficient generation if LNG is assured

Purpose: Within a few years it is expected that the longer-term firm generation needs and the viability of LNG for Hawaii will be better known. New firm generation resources will be added, and adding this capacity is expected to allow deactivation/decommissioning of existing generating units.

Scope: In the 2015–2016 time period, the Companies will implement an RFP process for new generation based on the forecast adequacy of supply for the operating system, the value of replacing aging generation units with more-efficient new ones, and the availability of environmentally-compliant fuels. The attributes, size, fuel(s), and total capacity (that is, MW) for the generating resources will be defined at that time, and be subject to approval by the Commission. This action will be implemented in coordination with Action 3.A.

2.C. Conversion of CIP CT-1 to Combined Cycle Operation

Purpose: To add a Heat Recovery Steam Generator to the discharge of the existing 113 MW CIP CT-1 combustion turbine and using the produced steam to operate a new 55 MW steam turbine. This project would not only add 55MW of capacity to the system, but would effectively result in 168MW of "new" high-efficiency baseload/cycling capability. Conversely, there will be a reduction of 113MW of peaking capability.

Scope: The Campbell Industrial Park Steam Turbine #1 (CIP ST-1) project would add approximately 55 megawatts (MW) of firm capacity to the Oahu energy system.

The project would be located at Hawaiian Electric's existing Campbell Industrial Park Generating Station on property that is already developed. Additional pieces of major equipment include a cooling tower, a generator step-up transformer, a selective catalytic reduction catalyst bed, and a new breaker bay in the existing AES substation. It is not expected that any new transmission lines will be required.

The electrical output from the CIP ST-1 project could supply power to all Oahu customers through the island-wide 138kV electrical grid. It is not expected that any new transmission lines will be required.

Major Milestones Dates

File Waiver Application: 3rd Quarter 2013
File PUC Application: 3rd Quarter 2014
Environmental Review Completed: 4th Quarter 2015
Start Construction: 1st Quarter 2017
In-Service Date: 4th Quarter 2018

Table 20-2. HECO CIP Project Capital Expenditures and Plant Addition Costs (Millions)

Project	Prior Years	2013	2014	2015	2016	2017	2018	Future Years	Total	In-Service Year
CIP Steam Turbine 1 Project	–	–	$1.00	$1.00	$10.00	$50.00	$88.00	–	–	2018

2.D. Re-negotiate Kalaeloa PPA

Purpose: To renegotiate a new power purchase agreement (PPA) with Kalaeloa Partners, LLP (KPLP), as the current PPA is set to expire in 2016.

Scope: In accordance with the approved waiver to the Competitive Bidding Framework, Hawaiian Electric will negotiate a new PPA or extension of the KPLP PPA for approval by the Commission. Negotiations will consider the current and future operational needs of the Oahu system, taking into account the growing amount of variable renewable generation on the grid and the need for generating unit flexibility. Execution and Commission approval of a new or extended PPA is contingent on a clear showing of value to Hawaiian Electric's customers.

3. Replace Oil with LNG

3.A. Liquefied Natural Gas Switching

Purpose: To reduce HECO, HELCO, and MECO customers' cost of electricity and comply with the requirements of EPA's air regulations, Mercury and Air Toxics Standards (MATS) and National Ambient Air Quality Standards (NAAQS), where applicable, by displacing liquid petroleum fuel with Liquefied Natural Gas (LNG). The ability to combust liquid petroleum fuel will be retained to enhance the flexibility and reliability of the units.

Scope: To support the development of a bulk LNG import and regasification terminal on Oahu and plan, design, and construct: pipelines to distribute natural gas to HECO's Waiau, Kahe, CIP, and Kalaeloa Partners L.P. (KPLP) generating stations; modifications to HECO's, HELCO's, and MECO's generating units to burn natural gas; and distribution of LNG to HELCO and MECO.

- Oahu LNG Import and Regasification Terminal

  HECO currently anticipates that the terminal will be designed and constructed by another entity and that terminal costs will be included in the cost of the LNG. Hence, HECO does not anticipate making capital expenditures for the LNG Import and Regasification Terminal at this time.

- LNG Supply and Purchase Agreement (SPA)

  HECO currently anticipates purchasing LNG from an LNG supplier and does not anticipate the need for capital expenditures in the export terminal or LNG carriers.

- Gas Pipeline(s) on Oahu to HECO's Waiau, Kahe, and CIP Generating Stations.

  Two alternatives are under consideration. The first alternative includes planning, designing, and constructing a new natural gas pipeline to connect the LNG Import and Regasification terminal to HECO's Waiau, Kahe, and CIP generating stations, and the KPLP generating station. The second alternative assumes re-use of existing pipelines where possible (requires further evaluation and analysis) and planning, designing, and constructing a new natural gas pipeline from the Kalaeloa area to the Kahe generating station.

- Distribution of LNG to HELCO and MECO

  HECO currently envisions LNG being distributed to HELCO's and MECO's facilities using ISO Containers that are loaded at the Oahu LNG Import and Regasification Terminal and barged to the neighbor islands. HECO anticipates that the cost of the LNG ISO containers to be included in the shipping cost to HELCO's and MECO's facilities.

- Modifications to the following generating units to add gas-firing capability.

  The following units are planned for modification to add gas-firing capability. It should be noted that liquid-fuel firing capability will be retained at all units. Units that are scheduled for either deactivation or decommissioning will not be modified to add gas-firing capability.

- HECO – Waiau 5, 6, 7, 8; Kahe 1, 2, 3, 4, 5, 6; and CIP1

  Assuming that the LNG Import and Regasification Terminal is completed in 2020, the unit modification work will likely start in 2018. Engineering will likely start around 2015. If small scale containerized LNG is financially feasible, we will proceed with modifications as soon as PUC approval is received.

- Early small scale containerized LNG distribution, where financially feasible

  If LNG can be sourced in small scale and delivered via ISO containers at prices lower than our current petroleum fuel prices, then portions of the project will be accelerated in advance of the LNG Import Terminal. It is anticipated that Molokai and Lanai are the best candidates for small scale LNG.

Table 20-3. HECO LNG Project Capital Expenditures and Plant Addition Costs (Millions)

Project	2013	2014	2015	2016	2017	2018	Future Years	Total	In-Service Year
Oahu LNG Terminal	–	–	–	–	–	–	–	–	–
LNG Supply and Purchase Agreement	–	–	–	–	–	–	–	–	–
Gas Pipeline Option 1 (Waiau, CIP, Kahe)	–	–	$5.2	$3.02	$5.86	$27.13	$80.18	$121.39	–
Gas Pipeline Option 2 (Kahe only)	–	–	$1.56	$1.69	$0.78	$10.73	$19.58	$34.34	–
Distribution Infrastructure to HELCO and MECO	–	–	–	–	–	–	–	–	–
Waiau 5 Gas Modifications	–	–	$0.24	$0.06	$0.03	$0.03	$2.55	$2.91	–
Waiau 6 Gas Modifications	–	–	$0.25	$0.06	$0.03	$0.03	$2.6	$2.97	–
Waiau 7 Gas Modifications	–	–	$0.39	$0.09	$0.04	$0.05	$4.44	$5.01	–
Waiau 8 Gas Modifications	–	–	$0.39	$0.09	$0.04	$0.05	$4.44	$5.01	–
Kahe 1 Gas Modifications	–	–	$0.39	$0.09	$0.04	$0.05	$4.44	$5.01	–
Kahe 2 Gas Modifications	–	–	$0.38	$0.09	$0.04	$0.05	$4.34	$4.89	–
Kahe 3 Gas Modifications	–	–	$0.39	$0.09	$0.04	$0.05	$4.44	$5.01	–
Kahe 4 Gas Modifications	–	–	$0.39	$0.09	$0.04	$4.11	$0.77	$5.4	–
Kahe 5 Gas Modifications	–	–	$0.6	$0.14	$0.06	$6.27	$1.18	$8.25	–
Kahe 6 Gas Modifications	–	–	$0.6	$0.14	$0.06	$6.27	$1.18	$8.25	–
CIP 1 Gas Modifications	–	–	$0.43	$0.1	$0.05	$0.05	$4.88	$5.51	–
Total	–	–	–	–	–	–	–	–	–

3.B. Diesel Conversion Projects

Purpose: Diesel Conversion Projects are planned in the event Hawaiian Electric must switch to ultra low sulfur diesel (ULSD) to comply with the requirements of EPA's air regulations; Mercury & Air Toxics Standards (MATS) and National Ambient Air Quality Standards (NAAQS).

Scope: Upgrade the steam generating units and fuel tank berms to switch from LSFO to diesel fuel.

- *Unit Conversion Projects:* Replace fuel pumping equipment and combustion components at each of the 12 generating units at the Kahe and Waiau power plants.

- *Fuel Supply System Upgrade Projects:* Upgrade the fuel supply systems (pumps & piping) that supply fuel from the tanks to the generating units at the Waiau power plants.
- *Tank Berm Upgrade Projects:* Install an impervious secondary containment system at the fuel tank berms at the Kahe & Waiau power plants, and Barbers Point Tank Farm.

Table 20-4. HECO Diesel Conversion Project Capital Expenditures and Plant Addition Costs (Millions)

Project	Prior Years	2014	2015	2016	2017	2018	Future Years	Total	In-Service Year
Waiau 3 Diesel Conversion	$0.1	$0.4	$1.1	–	–	–	–	$1.6	2015
Waiau 4 Diesel Conversion	$0.1	$0.4	$1.1	–	–	–	–	$1.6	2015
Waiau 5 Diesel Conversion	$0.1	$0.4	$0.9	–	–	–	–	$1.4	2015
Waiau 6 Diesel Conversion	$0.1	$0.4	$0.9	–	–	–	–	$1.4	2015
Waiau 7 Diesel Conversion	$0.1	$0.4	$1.0	–	–	–	–	$1.4	2015
Waiau 8 Diesel Conversion	$0.1	$0.4	$1.0	–	–	–	–	$1.4	2015
Waiau Fuel Supply System Upgrade	$0.1	$0.5	$2.6	–	–	–	–	$3.2	2015
Kahe 1 Diesel Conversion	$0.1	$0.4	$1.2	–	–	–	–	$1.7	2015
Kahe 2 Diesel Conversion	$0.1	$0.8	$0.8	–	–	–	–	$1.7	2015
Kahe 3 Diesel Conversion	$0.1	$0.2	$2.0	–	–	–	–	$2.3	2015
Kahe 4 Diesel Conversion	$0.1	$0.2	$1.7	$0.3	–	–	–	$2.3	2015
Kahe 5 Diesel Conversion	$0.1	$0.6	$0.7	–	–	–	–	$1.4	2015
Kahe 6 Diesel Conversion	$0.1	$1.1	$0.2	–	–	–	–	$1.4	2014
BPTF Fuel Tank Berm Upgrade	$0.1	$0.3	$7.7	–	–	–	–	$8.1	2015
Waiau Fuel Tank Berm Upgrade	$0.1	$0.3	$4.3	$1.3	–	–	–	$6.0	2016
Kahe Fuel Tank Berm Upgrade	$0.1	$0.3	$8.9	$3.1	–	–	–	$12.4	2016
Total	*$1.4*	*$7.1*	*$36.1*	*$4.7*	–	–	–	*$49.3*	–

3.C. Cooling Water Intake Structures

Purpose: Modify Cooling Water Intake Structures to comply with the pending EPA requirements under Section 316b of the Clean Water Act

Scope: Install fine mesh travelling screens and a fish return system at the Waiau and Kahe power plants

Table 20-5. HECO Cooling Water Project Capital Expenditures and Plant Addition Costs (Millions)

Project	Prior Years	2014	2015	2016	2017	2018	Future Years	Total	In-Service Year
316b	–	$0.1	$0.3	$0.5	$2.2	$2.7	$31.2	$37.0	2021

3.D. Kalaeloa Pipeline Project

Purpose: Kalaeloa Pipeline Project to provide Hawaiian Electric with the ability to solicit fuel supply contracts from off-island suppliers, import a lower emission fuel to support NAAQS compliance, create the flexibility to import fuel volumes beyond those provided in the refinery crude slate(s), generate alternate distribution pathways for additional security within the Company's fuel network, and increase the diversity of fuel suppliers in Hawaii.

Scope: To design and construct a mixed use fuel line(s) between Kalaeloa Barbers Point Harbor (KBPH) and Hawaiian Electric's Barbers Point Tank Farm (BPTF). Deliverables shall include a fuel hatch for barge loading and unloading at KBPH, valve manifolds for future connections to the Department of Transportation Harbor Division's (DOTH) proposed fuel pier, interconnections with Hawaiian Electric's existing pipelines, and provisions for long-term operation and maintenance of the pipeline(s).

Table 20-6. Project Capital Expenditures and Plant Addition Costs (Millions)

Project	Prior Years	2013	2014	2015	2016	2017	2018	Future Years	Total	In-Service Year
Kalaeloa Pipeline	$0.1	$1	$3	$14.5	$11.7	–	–	–	–	–

4. Other

4.A. Demand Response Strategy

Purpose: Hawaiian Electric's demand response (DR) strategy is to continue to develop a portfolio of residential, commercial and industrial customer loads that will enable reliable and economic operation of Hawaii's electric grid.[122] Hawaiian Electric has been taking steps to implement its DR strategy incrementally, over time, through a combination of shorter-term initiatives including, pilot programs, participation in research, development and demonstration (RD&D) projects, and market studies.

Scope: Hawaiian Electric's DR programs and initiatives have been categorized in this DR Action Plan as follows:

- Residential Direct Load Control
- Commercial and Industrial Direct Load Control
- Operationalize DR Initiative

Action plans for each of these programs and initiatives are described below.

4.A.1 Residential Direct Load Control (RDLC) Program

Program Description:[123] Hawaiian Electric's RDLC Program allows participation from eligible residential customers with electric water heaters and/or central air-conditioning (A/C) systems. The program is currently comprised of approximately 36,500 program participants who collectively contribute approximately 17 MW of system peak load reduction. Participants in the program receive the necessary technology (that is, hardware and services) at no cost and a financial monthly incentive for program participation. In exchange for allowing Hawaiian Electric to curtail their water heater and/or air conditioning (A/C) loads, participants receive a monthly electric bill credit of $3.00 for electric water heaters and $5.00 for A/C.

Hawaiian Electric has proposed expansion of the RDLC Program to (1) continue the current program for an additional five years (2013–2017), and (2) expand enrollment in the program by approximately 34,000 participants for an additional 18 MW of system peak load reduction.[124] This will result in

[122] See Hawaiian Electric Company, Inc.'s 2013 Annual Program Accomplishments and Surcharge Report (A&S Report), filed March 28, 2011, Docket No. 2007-0341, at 4.

[123] This description was taken from the document titled, "IRP 2013 Demand Response and PBFA DSM Programs" dated December 14, 2012.

[124] See Docket No. 2012-0079, *Application for Approval of Expansion of the RDLC Program*, filed April 13, 2012 (RDLC Expansion Application). On September 28, 2012, the Commission issued Decision and Order No. 30662 directing Hawaiian Electric to continue the RDLC Program through December 31, 2013, or until a final decision and order is issued. In its Order, the Commission stated that it "strongly supports the use of cost-effective and efficiently run demand response programs as invaluable resource options that should be utilized as an integral part of an electric utility's operations." Id. at 4. Furthermore, the Commission stated that "[d]emand response can also be used

cumulative participation of approximately 70,000 customers and a combined peak reduction of approximately 35 MW.

Action Plan and Initiatives

Hawaiian Electric proposes to further enhance the value and capabilities of traditional load management to examine new program technologies, program designs, and market and operational strategies for providing ancillary services support to integrating renewable resources. Hawaiian Electric's initiatives for the action plan period (2014–2018) include the following:[125]

- *Modify and Expand RDLC Program:* As stated above, Hawaiian Electric has requested Commission approval to continue the RDLC Program for an additional five years. Hawaiian Electric has also sought Commission approval to increase the size of the residential Water Heating program element (RDLC-WH) by a forecasted 8 MW of peak load reduction and expand the residential Air Conditioning program element by a forecasted 10 MW of peak load reduction.
- *Complete DR Potential Study:* A study planned to be completed in 2014 will estimate the amount of DR potentially available over the next 20 years. This study will use customer end-use data currently being collected by the Commission's consultant for the Commission's energy efficiency potential study. The customer end-use data is scheduled to be available before the end of 2013.
- *Innovation for DR Technologies:* Hawaiian Electric has issued a Request for Information (RFI) titled, "Innovation for Demand Response Technologies Residential & Small Business Sectors" on newer technologies that offer the potential to supplement and/or replace the deployment of legacy load management devices. The RFI will inform a subsequent request for proposals (RFP) for newer technologies, which Hawaiian Electric plans to issue in the 4Q 2013 – 1Q 2014 time frame.[126]. This initiative will also assist with determining timeline and decisions for pursuing DR communication infrastructure alternatives identified in Hawaiian Electric's telecommunication master plan.
- *Grid-Interactive Electric Thermal Energy Storage (GETS) Smart Water Heating Demonstration Project:* Hawaiian Electric plans to participate in a research, development and demonstration project with Electric Power Research Institute (EPRI) and Forest City Military Communities Hawaii (Forest City) for the field deployment and assessment of GETS smart water heater systems as a load management resource.[127] Lab testing for this

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to provide ancillary services and assist with the integration of additional renewable energy resources." Id.

[125] These action plan items are contingent on Commission approval of Hawaiian Electric's RDLC Expansion Application.

[126] This assumes that the Commission approves Hawaiian Electric's RDLC Expansion Application in 2013. Without Commission approval, Hawaiian Electric will not have program funds available to conduct an RFP.

[127] See RDLC Expansion, Docket No. 2012-0079, HECO Response to CA-IR-14, p.3, filed June 22, 2012.

GETS research was conducted in 2012.[128] The current phase of the GETS demonstration project is to augment the laboratory studies with multiple field placements of GETS enabled water heaters in the Hawaiian Electric service territory.[129] These field studies will provide valuable data on the actual performance of the grid interactive water heaters in customers' homes at Forest City's military housing complex and will help to identify any unforeseen impediments to wider scale deployment.

- *On Bill Financing for DR-Enabled Renewable Energy Generating Devices:* The Commission issued Decision and Order No. 30974 in Docket No. 2011-0186 stating that it is appropriate to require participants that avail themselves of on-bill financing for the use of renewable energy generating devices to participate in available and forthcoming demand response programs and ancillary services programs as a requirement to their use of financed renewable energy generation. Hawaiian Electric is a member of the On Bill Financing Working Group and will assist in identifying technical specifications and DR program design options for renewable generating devices such as solar water heaters and/or photovoltaic systems with a GETS-type DR control. *DR Community Outreach Campaign:* The introduction of newer innovative DR technologies presents an inflection point and opportunity for electric utilities to expand the market for consumer electronic (CE) and appliances that are DR-ready. These newer DR enabled CE and appliances will allow participants to be more engaged in monitoring and decision awareness of DR programs. Hawaiian Electric will be working with Forest City and Kanu Hawaii, a nonprofit sustainability volunteer organization, to launch a DR community outreach campaign, evaluate and test potential DR enabled CE products, and conduct market research for program design.

Table 20-7. HECO Demand Response Program Impacts and Estimated Expenditures (2014–2018)[130]

Year	Cumulative Program Peak Load Impacts (MW)
2014	20.9
2015	25.2
2016	29.8
2017	33.5
2018	36.0[131]

[128] See Hawaiian Electric's 2012 Annual Program and Modification and Evaluation (M&A) Report, filed November 30. 2012, Docket No. 2007-0341, at 43.

[129] Id

[130] With Commission approval for a budget carryover, the proposed program budget for 2013–2017 will be shifted one year to the 2014–2018 time frame.

[131] See RDLC Expansion Application, at 37.

Table 20-8. HECO RDLC Project Capital Expenditures and Plant Addition Costs (Millions)

Project	Prior Years	2013	2014	2015	2016	2017	2018	Future Years	Total
Total	*N/A*[132]	*$3.119*	*$5.661*	*$7.162*	*$7.613*	*$7.221*	*$6.283*	*N/A*	*$37.059*

4.A.2 Commercial and Industrial Load Control (CIDLC) Programs

Program Descriptions

Hawaiian Electric's operates two DR programs for commercial and industrial (C&I) customers: (1) the Commercial and Industrial Direct Load Control (CIDLC) program, and (2) the Fast DR Pilot Program. Hawaiian Electric has also proposed a C&I Dynamic Pricing Pilot (CIDP) Program to develop pricing incentives and disincentives for changes in customer behavior by allowing customers to respond to the changing cost of electricity.[133]

CIDLC

The CIDLC Program consists of two program elements: (1) the Direct Load Control (DLC) program element, which targets large C&I customers, and (2) the Small Business Direct Load Control (SBDLC) program, which targets smaller C&I customers.[134] As of the end of 2012, the CIDLC Program achieved 19 MW of curtailable load (approximately 18 MW from the DLC program element and approximately 1 MW from the SBDLC program element).[135]

DLC

The DLC program element targets large C&I customers who have non-critical or generator backed loads that can be controlled at Hawaiian Electric's system operator request. Participant's "controlled loads" are curtailed either: (1) as a dispatch curtailment event when there is a grid emergency such as when there is a real or anticipated shortfall in generation to meet a projected peak demand period, or (2) as an underfrequency load curtailment event when the system frequency falls below a specified level.[136] The DLC program element is currently being used to provide additional

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[132] Unlike capital projects, which Hawaiian Electric records expenditures for based on an in-service date, Hawaiian Electric's DR programs are ongoing so do not have discrete prior and future year expenditures that can be tied to a project and in-service date. Therefore, Prior Years and Future Years expenditures for DR programs have not been provided.

[133] See Docket No. 2011-0392, Application for Approval of a Commercial and Industrial Dynamic Pricing Pilot Program and Recovery of Program Costs, filed December 29, 2011 (CIDP Application), which is currently under Commission review.

[134] By Decision and Order No. 23605, filed August 15, 2007, in Docket No. 03-0415, the Commission approved the addition of the SBDLC program element.

[135] See 2013 A&S Report, filed March 28, 2013, in Docket No. 2007-0341.

[136] See 2012 M&A Report, filed November 30, 2012, in Docket No. 2007-0341, at 21.

system reliability, including system protection (that is, through underfrequency relay) and as an emergency dispatch resource.

SBDLC

Hawaiian Electric's SBDLC program element targets small and medium commercial customers with water heater and central air conditioner loads typically greater than 3 kW and less than 300 kW. Similar to the RDLC Program, Hawaiian Electric's current SBDLC participants have a one-way, radio-controlled LCR device installed on their water heater and/or central A/C appliances. The LCR device also includes a built-in under frequency relay that provides system protection (that is, the capability to automatically interrupt the load if the system frequency drops to a certain level).[137]

Fast DR Pilot Program

Since November 2011, Hawaiian Electric has been implementing a pilot program[138] designed to test the Hawaii C&I market's acceptance of newer DR technologies and quick response program designs that are intended to provide grid operational benefits for supporting integration of intermittent renewable resources.[139] The purpose of the Fast DR Pilot is to provide feedback for future modifications to the program design and operations of the CIDLC Program.[140] Participant loads are either controlled on an automated or semi-automated basis, with a 10 minute notification by the system operator.[141] As of May 31, 2013, Hawaiian Electric has enabled approximately 1.15MW of load reduction and contracted 2.36MW of load. In the third quarter of 2013, Hawaiian Electric will request Commission approval to complete the contracting and commissioning of a targeted 7MW of contracted load.

Commercial and Industrial Pricing Pilot Program

The CIDP Pilot offers tariff based dynamic pricing options for customers to participate in Hawaiian Electric's DR portfolio.[142] The CIDP Pilot relies upon the two-way communications infrastructure established in the Fast DR Pilot to initiate curtailment events and track customer loads.[143] Hawaiian Electric has proposed a two-year CIDP Pilot program during which commercial and industrial program participants will receive two forms of customer incentives: (1) a one-time technology incentive to help reduce or eliminate the upfront cost of purchasing and installing end-use equipment and

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[137] Id.

[138] See Docket No. 2010-0165, *Application for Approval of a Fast Demand Response Pilot Program and Recovery of Program Costs*, filed August 31, 2010.

[139] See 2012 M&A Report, at 4–5.

[140] Id. at 5.

[141] See 2013 A&S Report, at 32.

[142] See CIDP Application at 2.

[143] Id.

controls necessary to initiate load reductions, and (2) ongoing monthly incentives to retain the participant in the program.[144]

Action Plan and Initiatives

Hawaiian Electric desires to further enhance the value and capabilities of traditional load management to examine new program technologies, program designs, and market and operational strategies for providing ancillary services support to integrating renewable resources. Hawaiian Electric's C&I DR initiatives for the action plan period (2014–2018) include the following:

- *Expand FastDR Customer Enrollment and Modify CIDLC Program:* Continue efforts to expand enrollment in the Fast DR Pilot Program and seek approval to modify the CIDLC Program to incorporate lessons learned and best practices from the FastDR Pilot Program as program modifications to the existing C&I DR portfolio.[145]
- *Modify Expand Small Business Direct Load Control Program*[146]*:* Expansion of the Small Business Water Heating Program Element (SBDLC-WH). Electric Water will add approximately 700 participants and contribute approximately 450 kW of additional peak load reduction. Small Business A/C Program Element (SBDLC-AC): A/C will add approximately 1,200 participants and contribute approximately 2,550 kW of additional peak load reduction. Existing SBDLC program rules will be modified to enable utilization of the SBDLC Program as a tool to support the management of grid operations based on the framework for dispatchable DR developed by the North American Electric Reliability Corporation (NERC). *Technology Assistance/Technology Incentives (TA/TI) Smart Building Initiative:* Provide technical assistance to C&I customers to participate in DR programs and provide customers with opportunities to retro-commission buildings for integrated DR/energy-efficiency savings.[147] Hawaiian Electric will propose the TA/TI Smart Building Initiative as a best practice in the upcoming 2013 M&E Report for the CIDLC Program for implementation in 2014 without requesting additional funding.
- *Hospitality Study:* Conduct a Research, Development and Demonstration Project with Electric Power Research Institute (EPRI) and Lawrence Berkeley National Lab (LBNL) to develop DR strategies for hot and humid climates and to evaluate participation and performance of the hospitality industry in DR Programs. [148]
- *Complete DR Potential Study:* A study planned to be completed in 2014 will estimate the amount of DR potentially available over the next 20 years. This study will use customer end-use data currently being collected by

[144] Id.

[145] See 2012 M&A Report, at 5 ("The ultimate purpose of the Fast DR Pilot is to provide feedback for future modifications to program design and operations of the CIDLC Program.")

[146] Modification and expansion of the SBDLC Program assumes Commission approval of Hawaiian Electric's SBDLC Expansion Application.

[147] See 2012 M&A Report, at 37.

[148] See 2012 M&A Report, at 43.

the Commission's consultant for the Commission's energy efficiency potential study. The customer end-use data is scheduled to be available before the end of 2013.

- *Demand Response for Schools:* The introduction of two-way communication technologies creates a great opportunity for utilities to be able to actually measure the available load impact at any given time. Two-way communication also allows participants to be more involved in monitoring their energy use. In order to assess the available devices not only at the technology level but with the user community, Hawaiian Electric has begun discussions with the State of Hawaii Department of Education regarding the possibility of having schools assist with field trials of potential DR technologies that are down-selected during the RFI process.
- *Demand Response for Water Pumping Loads:* In the Reliability Standards Working Group Proceeding,[149] the Demand Side Options (DSO) Subgroup presented a white paper titled, "Demand Response as a Flexible Operating Resource" (RSWG DSO Report). In the white paper, the DSO Subgroup recommended that the Hawaiian Electric Companies explore and develop DR programs that can be implemented in the near term, such as DR programs for water pumping loads.[150] Accordingly, Hawaiian Electric will pursue the study and design of special customer tariffs that will encourage the ancillary services integration of DR into the Honolulu Board of Water Supply operations. The opportunity to study, design and propose special customer tariffs for the Honolulu Board of Water Supply is expected to begin in the 2014 time frame. Hawaiian Electric is also currently working with the United States Army, which is a participant in the Fast DR Pilot Smart Building Initiative, to implement AutoDR technologies for water pumping loads.

Table 20-9. HECO CIDLC Program Impacts and Estimated Expenditures (2014–2018)

Year	Cumulative Program Peak Load Impacts (MW)
2013	26.0
2014	30.0
2015	32.0
2016	35.0
2017	37.0

[149] Docket No. 2011-0206.

[150] RSWG DSO Report at 16.

Table 20-10. HECO CIDLC Projected Program Cash Flows (Millions)

Project	Prior Years	2013	2014	2015	2016	2017	2018	Future Years	Total
Commercial & Industrial	N/A	10.293	7.901	8.077	8.639	7.657	N/A	$42.566	

4.A.3. Operationalizing Demand Response

Purpose: Hawaiian Electric plans to create an integrated suite of tools and telecommunications infrastructure to enable the effective, reliable, secure and scalable dispatch and management of Hawaiian Electric's DR programs through the development and implementation of a Demand Response Management System (DRMS) and Customer Relationship Management (CRM) system, the planning, mobilization and implementation of a DR Telecommunication Plan, and related cyber security activities.

Inherent in the flexibility in the delivery of DR functions are a number of different business models and technical solutions that can be utilized. While the business models and technical solutions vary, the DR programs should be designed to meet the system operational needs and Hawaiian Electric system operators must be the entity to manage the DR control function.

An integrated DR operation (DRMS, CRM, telecom and cyber solution) will increase the operational efficiency of DR event performance by optimizing the portfolio of DR programs by consolidating the disparate, legacy DR components, and newer planned systems.

The implementation of an integrated DR solution and development of associated practices and processes will result in a flexible and reliable system beneficial to both external constituents (customers, aggregator and internal stakeholders). Hawaiian Electric's Operationalizing DR initiatives for the action plan period (2014–2018) include the following:

Action Plan

- *Develop Plan for DR Communications:* Develop a roadmap for a long-term DR communications solution to identify major milestones and decision points. From the roadmap, the RFI and external inputs from the Telecommunications Master Plan and Integrated Resources Plan, develop an actionable DR Telecommunications Plan.
- *Implement DR Telecommunications Plan:* Implement the DR Telecommunications Plan in conjunction and in collaboration with other Hawaiian Electric initiatives, such as an AMI project, to take advantage of technical interdependencies and potential cost savings.
- *Specify DRMS Functionality and Select DRMS:* With key stakeholders, develop functional specifications for the DRMS. Issue a Request for Proposal (RFP) and select a DRMS vendor.
- *Implement DRMS:* Implement the DRMS to aid in the management and operations of multiple DR systems; communication technologies, DR

event forecasting and support back office management and administration processes, such as settlement processing, baseline calculation, post DR event impact analysis, and customer information and performance. The development and implementation of a DRMS is a strategic initiative for the effective and efficient operations of Hawaiian Electric's DR portfolio.

- *Develop Scalable and Flexible Business and Operational Processes:* Develop the processes required to enroll, manage, and maintain program participants, including specification of participant DR devices that meet security and privacy requirements. Create the reporting required to assess overall performance of the DR portfolio, including, but not limited to, tracking participant status and performance, post DR event impact, and evaluation of DR forecast to actual event impacts.
- *Select and Implement a CRM System:* Based on previously defined functional specification, select and implement a CRM. The CRM will track all transactions with participants, including sales and enrollment and associated documents, contract administration, and customer information, and end-use equipment controlled.
- *DRMS Integration with AGC and EMS/SCADA:* Coordinate and assist in the development of dispatch criteria to support the dispatch and integration of DR programs into AGC and EMS/SCADA. Automate dispatch of DR programs based on a signal from AGC and EMS/SCADA, including identification and provisioning of data necessary to support AGC dispatch, generation ramp requests for renewable wind integration and surgical DR for feeder congestion.
- *DRMS Integration with Hawaiian Electric Business Systems (SAP, MV-90, DR CRM, etc.):* Phased implementation of customer data transfer between Hawaiian Electric business systems and potentially other DR head-end systems with the DRMS.
- *DR Telecommunications Plan:* The RDLC and CIDLC Programs utilize a one-way 929 MHz paging system provided by a third-party service provider, USA Mobility. For the residential and small business DR customers, the outcome of the information gathered from the Innovation for DR Technologies Request for Information and subsequent Request for Proposal will provide Hawaiian Electric options for deploying newer DR technologies that are IP-based and do not rely upon paging radio frequencies. In the 2014 time frame, Hawaiian Electric will evaluate the longer-term (10-year) requirement for the continued operation of the one-way 929 MHz paging system. As needed, Hawaiian Electric will consider the business case justification for pursuing the DR capital project component of the Telecommunication Master Plan or the continuation of the third-party lease operations provided by USA Mobility.
- *DR Cyber Security Activities:* As the role of Hawaiian Electric's DR portfolio is expanded, so does its visibility and impact to system operations for meeting not only peak demands but also for engaging in the daily load balancing operations of the system. Like other critical

infrastructure, Hawaiian Electric recognizes the significant challenges associated with keeping customer data and DR communications secure. Current systems are protected by the inherent nature of a one-way control environment. In the future, there will be an increased need to secure the existing (one-way) and future (two-way) DR ecosystems. As part of U.S. Department of Energy National Energy Technology Laboratory (US DOE NETL) funding opportunity announcement Hawaiian Electric, Honeywell Laboratories, University of Illinois at Urbana Champaign, Pacific Northwest National Labs and Great River Energy have assembled a team to bring together the research, product development and operations organizations to transition R&D technologies for DR system architecture that provides data integrity protection, DR command validation, and DR system based response from an open internet environment. Hawaiian Electric will participate in the installation and testing of the developing technologies under this proposed grant project (pending confirmation and award by the US DOE NETL).

Table 20-11. HECO Demand Response Estimated Expenditures

Year	Total
2013	$87,000
2014	$638,500
2015	$644,000
2016	$198,500
2017	$198,500
2018	$198,500
Total	*$1,965,000*

4.B. Operational Flexibility Projects

Purpose: Operational Flexibility Projects to modify the baseload steam units, and their associated generating stations, to allow more intermittent energy to be accepted onto the system to meet RPS compliance in 2020.

Scope: Design and install projects necessary to enable cycling operations, reduce minimum loads to the targets identified in the Oahu Wind Integration and Transmission Studies (OWITS). In addition, modifications to the generating units to enable daily/seasonal cycling operation will be evaluated and may be implemented. The benefits of reducing the minimum load of the baseload units were quantified in the OWITS. Unit projects required to reduce the minimum load include:

- Full-stream condensate polishers
- Burner system modifications
- Boiler feed pump variable frequency drives or soft-start capability
- Air preheater corrosion protection

- Low-pressure turbine drain valve temperature monitoring

Potential station projects include waste water treatment system upgrades, depending on the condensate polisher technology and waste stream product.

Table 20-12. HECO Operational Flexibility Target Minimum Loads

Unit	Current Net Min Load (MW)	New Target Min Load (MW)[1]	Estimated EMS Minimum (MW)[2]	Normal Top Load
Kahe 1	32.5	15	25	86
Kahe 2	32.7	15	25	86
Kahe 3	32.3	15	25	90
Kahe 4	32.3	15	25	89
Kahe 5	50.7	25	35	142
Kahe 6	50	50	50	142
Waiau 7	32.6	15	25	87
Waiau 8	32.8	15	25	90

1: Boilers must remain in service during a loss of load event.

2: EMS Minimum includes downward regulating reserves based on transmission line loading

Table 20-13. HECO Operational Flexibility Project Capital Expenditures and Plant Addition Costs (Millions)

Project	Prior Years	2013	2014	2015	2016	2017	2018	Future Years	Total	In-Service Year
Kahe 1 OPFLEX		$0.301	$2.247	$6.783	$0.5	$0	$0		$9.336	2015
Kahe 2 OPFLEX		$0	$0.031	$0.916	$6.995	$0	$0		$7.942	2016
Kahe 3 OPFLEX		$0	$0	$0	$0.659	$7.391	$0		$8.05	2017
Kahe 4 OPFLEX		$0	$0	$0	$0.183	$2.063	$5.458		$7.704	2018
Kahe 5 OPFLEX		$0.120	$0.037	$2.071	$6.555	$0	$0		$8.783	2016
Kahe 6 OPFLEX		$0	$0	$0.066	$1.027	$6.591	$0.493		$8.177	2017
Waiau 7 OPFLEX		$0	$0	$0.042	$2.273	$6.063	$0		$8.378	2017
Waiau 8 OPFLEX		$0.183	$0.823	$5.516	$2.147	$0	$0		$8.669	2016
WPP OPFLEX		$0	$0	$0	$0.811	$3.402	$0		$4.213	2017
KPP OPFLEX		$0	$0	$0	$0.135	$5.045	$0.014		$5.194	2017
Total										

4.C Energy Efficiency

Purpose: While the Companies no longer administer any energy efficiency rebate programs, they remain committed to providing their customers with educational support to manage their electricity bills through energy efficiency and through demand response programs. The Companies also continue to assist in regulatory initiatives that further the objectives of the Hawaii Clean Energy Initiative (HCEI).

Scope: Hawaiian Electric's five-year energy efficiency action plan consists of the following initiatives:

- Collaborate with Hawaii Energy on responding to customer inquiries regarding Hawaii Energy's energy efficiency programs, providing educational information on energy efficiency and conservation, placing additional focus on low-income customers, and more closely integrating the separate administration of energy efficiency and demand response programs.
- Implement billing, collection, and transmittal of revenues for On-Bill Financing (OBF) and Green Infrastructure.
- Continue to administer the electric vehicle time-of-use pilot rates if granted an extension by the Commission, and
- Implement public electric vehicle charging facility tariffs, including Schedules EV-F and EV-U if approved by the Commission.

On-Bill Financing (OBF)

The Companies are heavily involved in on-going Commission-led efforts to implement OBF by January 2014.[151] OBF has the promise of making energy efficiency measures available to customers without an upfront cost. Repayments can be made over time through the monthly electric bill. The obligation to repay the upfront cost remains with the premise in which the energy efficiency measure is installed, and not the occupant of the premise. Therefore, OBF may be a major step forward in penetrating the rental market.

The Companies are members of the OBF Working Group, co-lead the Utility Integration Subgroup (with Kauai Island Utility Cooperative) and are members of the two remaining subgroups (Program Design and Administration, and Finance Administration).

Green Infrastructure

A Green Infrastructure Program was proposed under SB1087 and was signed into law on June 27, 2013. The Green Infrastructure Program provides for state-issued revenue bonds as an alternative source of capital for OBF. Under the legislation, the Companies would include a non-bypassable Green Infrastructure Fee on all customers' bills that would collect revenues used to repay the bondholders.

PBFA Energy Efficiency Programs

The Companies continue to support Hawaii Energy, the Commission's Public Benefits Fund Administrator (PBFA), by providing customer data that

[151] Docket No. 2011-0186, Decision and Order No. 30974, February 1, 2013.

is necessary for the PBFA to assist customers with energy audits and energy efficiency program customer rebates. In addition, both Hawaii Energy and the Hawaiian Electric Companies are moving to collaborate more closely on making energy efficiency more accessible by customers. On January 24, 2013, the Reliability Standards Working Group[152] approved a Demand-side Options Subgroup (DSO) Whitepaper[153] that recommended Hawaii Energy be required to "[W]ork with the utilities to identify those customers and loads that are most promising for demand response, and assure that Hawaii Energy and the DR planners coordinate program plans and marketing to assure that energy efficiency does not compromise promising DR opportunities (and vice versa)". This effort is identified within the Companies' DR action plans.

Educational Resources

The Companies are providing basic educational materials that help them understand and implement energy savings behaviors. Educational outreach to customers includes mobile displays of energy saving information that are exhibited at community fairs, conferences and public events, as well as the Home Energy Challenge public elementary school program that teaches families to conserve energy at home. The Companies also provide an on-line energy audit for residential customers that give energy conservation and energy efficiency tips to help customers reduce their electrical usage. The on-line Going Solar resource center provides information on solar water heating and other energy efficient technologies. Customers that want to participate in Hawaii Energy's customer rebate programs are referred to Hawaii Energy.

4.D. Low-Cost Biofuels

Purpose: To source low-cost biofuels as a part of the portfolio of renewable energy consistent with the Company's commitment to the Hawaii Clean Energy Initiative and the State's Renewable Portfolio Standards Requirements.

Scope: Biodiesel with federal subsidies are potentially cost competitive with ULSD. In fact, biodiesel is a renewable substitute for what is currently the Companies' highest price grade of fossil fuel, ULSD. ULSD is currently supplied primarily on the basis of truck tanker delivery transportation sourced at on-island facilities. This logistical arrangement is entirely consistent with the smaller-scale biodiesel producers' processing and distribution capabilities.

Hawaiian Electric is preparing to issue a Request for Proposal (RFP) in 3Q 2013 seeking supplies of ULSD focused on the procurement of generation fuels for HELCO and MECO, whose current ULSD supply arrangements expire at the end of 2014. This Inter-Island Fuel Supply RFP will offer biodiesel suppliers, including but not limited to local biodiesel producers,

[152] Docket No. 2011-0206.

[153] RSWG Demand-Side Options Subgroup, *Demand Response as a Flexible Operating Resource*, December 5, 2012.

the opportunity to offer competitively priced supplies of fuel for all or part of the Companies' ULSD required volumes consumed on the Islands of Hawaii, Lanai, Molokai and Maui.

As additional supplies of renewable liquid fuels become increasingly cost effective and more commonly available, through local production or bulk importation, for example, Hawaiian Electric may issue successive renewable fuel RFPs later in the decade for additional amounts of biofuel in order to meet increasingly stringent environmental regulations on engine and boiler emissions or for consumption in the Companies' generating facilities in order to comply with State 2020 and later RPS goals.

Clean Energy Future

5. Meet or Exceed Renewable Portfolio Standards

5.A. Firm Generation RFP

Purpose: To pursue new firm dispatchable, quick-start, high-efficiency, fast ramping generation that has multi-fuel capability. Adding new firm capacity allows Hawaiian Electric the flexibility to then consider deactivation and decommission of existing generation.

Scope: Firm power resources (for example, dispatchable, high-efficiency, fast ramping, multi-fuel reciprocating engines) will be procured as part of the RFP process described for Action 2b.

5.B. Non-Firm Generation and Undersea Cable RFP

Purpose: To competitively procure renewable energy delivered to the Oahu grid, from both On-Oahu and Off-Oahu resources, consistent with the Company's commitment to the State's Renewable Portfolio Standards Requirements.

Scope: Continue with Renewable Energy RFP as directed by the Commission. The cost effectiveness of energy delivered to Oahu from Off-Oahu resources via a generation tie is dependent on the total cost of generation, undersea cables, and on-Oahu transmission infrastructure. Additionally, the IRP analysis as discussed in *Chapter 11: Inter-Island and Inter-Utility Connection Analysis*, illustrates the potential benefit of connecting the Maui and Oahu, and Hawaii and Oahu grids. If directed by the Commission, modify RFP or issue separate RFP to support grid tie consideration.

5.C. Hawaii BioEnergy Contract

Purpose: To integrate renewable fuel into existing generation, consistent with the Company's commitment to the Hawaii Clean Energy Initiative and the State's Renewable Portfolio Standards Requirements.

Scope: Contract is pending Commission approval.

5.D. Energy Delivery

Purpose: To interconnect renewable energy resources into the grid, consistent with the Company's commitment to the Hawaii Clean Energy Initiative and the State's Renewable Portfolio Standards Requirements.

Scope: Install necessary transmission and distribution facilities to interconnect various renewable resources.

Table 20-14. HECO RPS Project Capital Expenditures and Plant Addition Costs (Millions)

Project	Prior Years	2013	2014	2015	2016	2017	2018	Future Years	Total	In-Service Year
Photovoltaic Projects			$3.634	$4.408	$0.082	-	-		$8.124	
Other Renewables			$1.354	-	-	-	-		$1.354	
Total										

5.E. Self-Build Utility-Scale PV Resource Development, including a Resource at Kahe Generating Station

Purpose: To serve the health and welfare of the community through the provision of a renewable power source, thereby facilitating both a reduction in the State's dependence on imported fossil fuel and efforts toward energy self-sustainability and self-sufficiency in furtherance of the Hawaii Clean Energy Initiative.

Scope: Hawaiian Electric will develop low-cost, fast-track, self-build utility-scale PV projects, including a project at Kahe Power Plant, for which they will seek a waiver from the Competitive Bidding Framework, subject to the Commission's approval.

Major Milestones Dates:

File Waiver Application: 3rd Quarter 2013

File PUC Application: 1st Quarter 2014

Environmental Review Completed: 4th Quarter 2013

Start Construction: 4th Quarter 2014

In-Service Date: 3rd Quarter 2015

Table 20-15. HECO PV Project Capital Expenditures and Plant Addition Costs (Millions)

Project	Prior Years	2013	2014	2015	2016	2017	2018	Future Years	Total	In-Service Year
Kahe Utility-Scale Photovoltaic (PV) System			$1	$44					$45	2015

5.F. Continue to Consider Lanai Wind Project

Purpose: To interconnect renewable energy resources into the Oahu grid, consistent with the Company's commitment to the State's Renewable Portfolio Standards Requirements.

Scope: Negotiate power purchase agreement with Castle & Cooke in accordance with 2011 Term Sheet. Lanai Wind project is dependent on successful outcome of PPA negotiations and the Non-Firm Generation and Undersea Cable RFP described in item 5.B

5.G. Implement Approved RSWG actions

Purpose: To interconnect renewable energy resources into the Oahu grid, consistent with the Company's commitment to the State's Renewable Portfolio Standards Requirements, in a safe and reliable manner.

Scope: Support and implement Commission-approved RSWG actions, including, but not limited to adoption of new reliability standards and participation in follow up regulatory proceedings.

Modernize Grid

6. Improve Grid Operations

6.A. Schofield Generating Station

Purpose: To provide additional capacity that will enable increased levels of intermittent renewable energy, increase system efficiency, provide fast start (8-minute) dispatchable capacity, and mitigate the risks of a natural disaster.

Scope: The Schofield Generating Station (SGS) project will add approximately 50 megawatts (MW) of load following/peaking/cycling generation consisting of six 8.4 MW biofueled reciprocating engine-generator sets and associated equipment. The engines will be capable of being individually started and dispatched to provide incremental capacity as needed. The project consists of construction of new generation as well as electrical transmission interties.

The project will be located on 10.3 acres within property owned by the United States Army in Wahiawa, Hawaii. This property is an undeveloped site with no established infrastructure. The SGS project will include a 2-mile aboveground 46kV transmission line connected to the existing Hawaiian Electric grid.

The electrical output from the SGS generators will normally supply power to all Oahu customers through the island-wide electrical grid. However, during outages that meet the criteria specified in the Operating Agreement, SGS output will be "islanded" to serve only the Army facilities at Schofield Barracks, Wheeler Army Air Field, and Kunia.

Major Milestones Dates:

File Air Permit Application: 3rd Quarter 2013

File PUC Application: 1st Quarter 2014

Final EIS Completed: 3rd Quarter 2014

Start Construction: 3rd Quarter 2016

In-Service Date: 3rd Quarter 2017

Table 20-16. HECO Schofield Station Project Capital Expenditures and Plant Addition Costs (Millions)

Project	Prior Years	2013	2014	2015	2016	2017	2018	Future Years	Total	In-Service Year
Schofield Generating Station			$1.454	$12.041	$84.844	$79.865	$5			2017

6.B. Transmission & Distribution

Purpose: To ensure the physical safety of our customers and Company personnel.

Scope: Retire certain existing equipment or facilities and install new equipment or facilities that would mitigate certain hazardous conditions.

Table 20-17. HECO Arc Flash Mitigaion Project Capital Expenditures and Plant Addition Costs (Millions)

Project	Prior Years	2013	2014	2015	2016	2017	2018	Future Years	Total	In-Service Year
Arc Flash Mitigation			$2.124	$2.168	$2.210	$2.252	$2.295		$11.049	

Purpose: To demonstrate environmental leadership or compliance for transmission and distribution facilities.

Scope: Retire certain transmission and distribution facilities and install new facilities that comply or exceed environmental regulations.

Table 20-18. HECO Substation Lighting Project Capital Expenditures and Plant Addition Costs (Millions)

Project	Prior Years	2013	2014	2015	2016	2017	2018	Future Years	Total	In-Service Year
Substation Lighting			$0.218	$0.241	$0.265	$0.292			$1.016	

Purpose: To meet customer requests for new service or relocation of existing transmission and distribution facilities.

Scope: Install new transmission and distribution facilities or relocate existing facilities to address customer initiated projects.

Table 20-19. HECO T&D New Load and Relocation Project Capital Expenditures and Plant Addition Costs (Millions)

Project	Prior Years	2013	2014	2015	2016	2017	2018	Future Years	Total	In-Service Year
New Load Projects			$1.97	$7.91	$14.48	$1.86	$29.93		$56.15	
Relocation Projects			$82.29	$109.99	$6.57	$5.03	$4.90		$208.78	
Total										

Purpose: To modernize the grid.

Scope: Proactively retire certain transmission and distribution assets and installing new facilities in a strategically, planned approach.

Table 20-20. HECO Grid Modernization Project Capital Expenditures and Plant Addition Costs (Millions)

Project	Prior Years	2013	2014	2015	2016	2017	2018	Future Years	Total	In-Service Year
Transmission			$68.56	$102.95	$148.41	$130.82	$39.96		$490.70	
Sub-transmission			$13.14	$15.17	$14.77	$11.99	$10.51		$65.58	
Distribution			$60.21	$110.89	$121.18	$156.33	$148.83		$597.43	
Total										

Purpose: To maintain and improve the level of electric service to customers by reducing the number of outages and reducing the duration of outages.

Scope: Install new transmission and distribution facilities and integrate smart grid technologies.

Table 20-21. HECO Reliability Project Capital Expenditures and Plant Addition Costs (Millions)

Project	Prior Years	2013	2014	2015	2016	2017	2018	Future Years	Total	In-Service Year
Reliability			$4.70	$5.98	$4.96	$4.89	$4.89		$25.43	
Distribution Automation			$5.67	$9.60	$9.56	$21.04	$3.32		$49.19	
Total										

Purpose: To control costs for customers and offer value to customers.

Scope: Install capital improvements to create operational efficiencies to achieve long-term lower costs and value for customers.

Table 20-22. HECO Operartional Improvements Project Capital Expenditures and Plant Addition Costs (Millions)

Project	Prior Years	2013	2014	2015	2016	2017	2018	Future Years	Total	In-Service Year
Central Baseyard & Warehouse			$5.708	$23.678	$43.342	$34.239	$0.286		$107.253	
Operational Improvements			$4.094	$5.464	$3.811	$1.994	$2.195		$17.558	
Total										

6.C. Smart Grid

Purpose: To transform the existing grid into a “smarter”, more efficient, more reliable grid that integrates more renewable energy through the use of various technologies and capabilities and provide more information and options to customers with the overall goal of reducing costs and improving service to our customers. The initial Smart Grid deployments will be functionally and/or geographically targeted, with a commitment for island-wide deployment of smart meters (with opt out option) for Oahu.

Scope: The HECO Smart Grid five-year action plan includes Advanced Metering Infrastructure (AMI), Distribution Management System (DMS), Smart Grid Demonstration Projects, and Smart Grid Research and Development. The AMI action plan includes Conservation Voltage Reduction (CVR) and a Pre-Pay program.

The Company will be updating the AMI business case for full AMI deployment across all three service territories. This update will take advantage of the lessons learned from other utilities that have implemented AMI, identify new capabilities which have been proven at other utilities (such as CVR and Pre-Pay) since the Company's last AMI financial analysis (2008) and business case (2009). The Company will also leverage the information that has been obtained through the Company's interaction with the Electric Power Research Institute (EPRI) and EPRI-member utilities throughout the world. The updated business case, including additional use cases, benefits and functional and technical requirements, will be developed through 2014, followed by a competitive RFP and vendor selection process. The application and approval process with the Commission will follow and run through 2015. Contingent upon Commission approval, AMI implementation is planned to begin in 2016, starting with the deployment of a Meter Data Management System (MDMS) that will be shared by HECO, MECO and HELCO Meter replacements at HECO will begin no later than 2017 (along with related CVR and the Pre-Pay program) and be completed in 2018.

Table 20-23. HECO AMI Project Operation and Maintenance Costs (Millions)

Project	Prior Years	2014	2015	2016	2017	2018	Future Years	Total	In-Service Year
AMI (HECO)	$0.436	$1.667	$1.572	$5.358	$18.914	$19.482	$0.000	$47.430	2017, 2018

Table 20-24. HECO AMI Project Capital and Deferred Costs (Millions)

Project	Prior Years	2014	2015	2016	2017	2018	Future Years	Total	In-Service Year
AMI (HECO)	$0.039	$0.370	$0.353	$10.488	$39.022	$40.192	$0.000	$90.464	2017, 2018

Distribution Management System

Hawaiian Electric currently has an EMS system that is used for automatic generation control and the supervisory control and data acquisition (SCADA) functions primarily focused on the bulk power system that includes the generation and transmission systems of the power grid. A Distribution Management System (DMS) contains capabilities that are focused on distribution systems as the name suggests. As additional SCADA enabled distribution equipment are installed, advanced control center solutions can be employed to take full advantage of the increased visibility and automation available across the network. The outage management system leverages the increased visibility of the network made possible by feedback from automation equipment including FCIs, reclosers, and switches. Additionally, distribution network applications, as part of a distribution management system, help to assess and analyze the state of the network in terms of load, voltage, and disturbances. In terms of reliability, the DMS helps to more quickly locate faults through advanced fault location. The DMS assists the operator in making recommendations including isolation and restoration actions, especially important for medium to high load conditions and areas of high interconnectivity, and proactively helps to avoid outages by assessing network conditions. Introduction of the DMS is recommended in later half of the 2-5 year stage of a distribution automation expansion on Oahu with initial focus on the highly utilized (heavily loaded) and highly interconnected portions of the network. A DMS assessment project is being planned for 2014 that will assess the requirements, benefits, and available options of DMS systems and configurations that are available and to what extent these benefits can be leveraged between the Hawaiian Electric companies. Once the system requirements are determined an RFP will need to be issues to obtain vendor proposals and finally PUC approval and procurement. The cost of the DMS system provided below is a rough estimate that will need to be refined as part of the DMS assessment work.

Table 20-25. HECO Distribution Management System Distribution Management System O&M Costs (Millions)

Project	2014	2015	2016	2017	2018	Future Years	Total	In-Service Year
Distribution Management System (Oahu)	0.4	0.1			0.5			

Note: 2018 expense is an annual maintenance fee of approximately 15%

Table 20-26. HECO Distribution Management System Capital and Deferred O&M Costs (Millions)

Project	2014	2015	2016	2017	2018	Future Years	Total	In-Service Year
Distribution Management System (Oahu)				1.5	1.5			

Smart Grid Demonstration Projects

The Companies will continue to implement and support the ongoing smart grid demonstration projects on Maui leveraging funding from the Department of Energy (DOE) and the New Energy and Industrial Technology Development Organization (NEDO) of Japan. The utilities role is primarily to provide oversight and project management support in 2014 and 2015 after which the demonstrations will conclude. New systems and capabilities that are developed through these projects will then be assessed to determine if the deployment should be expanded to obtain greater benefits to the system and our customers.

Smart Grid Research and Development

In addition to the demonstration projects funded by outside sources, the company will continue to work with industry research partners such as the Electric Power Research institute and the Department of Energy to develop new tools and capabilities that are specific to the needs of our islanded systems or adapt systems or solutions deployed at other utilities to work with our rapidly changing system. This includes new data acquisition and data analytics systems that acquire data from the grid, but more importantly process the large sets of data streams coming in from AMI and other intelligent electrical devices installed on the grid and provide the information or recommendations that system operators need to operate what has become a much more dynamic systems.

Table 20-27. HECO Smart Grid Project Capital Expenditures and Plant Addition Costs (Millions)

Project	Prior Years	2014	2015	2016	2017	2018	Future Years	Total	In-Service Year
Smart Grid R&D (HECO)		$0.425	$0.425	$0.425	$0.425	$0.425		$2.125	N/A

6.D. Telecommunications

Purpose: To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

Scope: To strategically implement the upgrade of the telecom infrastructure in the following six project categories.

- *Tier 1 & 2 (Infrastructure and Electronics):* Key backbone fiber optic cables, high capacity microwave radios, and high-speed, high-capacity electronic equipment linking and providing service to, critical company sites. Carries data traffic between all areas of the Company, including, but not limited to, all types of SCADA, Business IT LAN, Demand Response, Security Video, Advanced Metering, Mobile Radio, Protective Relaying, and Renewable Integration.
- *Tier 3 (Comm to Distr. Subs, Comm Sites, etc):* Lower capacity, point-to-point communications which connect Distribution Subs, Utility Comm Sites, and other locations into the Tier 1&2 comm backbone. Data transported includes, but is not limited to, Distribution SCADA, IT Hot-spots for Mobile Computing, Demand Response, Security Video, Advanced Metering, and Land Mobile Radio voice trunks.
- *Demand Response and Prorated Frequency Purchase for DA, DR, SG, AMI Collector Points:* Allows the continued use of the existing paging network and existing end devices to continue Demand Response service to customers and then install a replacement system when the existing paging contract expires. Frequencies will need to be purchased for the point-to-point and point-to-multipoint radio links between the Tier 3 sites and the Tier 4 collector points. These radio links will carry the DR, DA,

SG, and AMI data to and from the Tier 1 and Tier 2 backbone network. The cost of the frequency purchase is allocated among the Companies.

- *Tier 4 Collector Points for DA, DR, SG, and AMI:* Data Collection systems located throughout the service areas of all three Companies. These collect data from various end-user applications and devices including, but not limited to, Distribution Automation, Mobile Radio, Advanced Meters, EV Charging Stations, etc.
- *Communications Network Operations Center (NOC):* Will monitor the health of the communications systems across all three Companies, and provide the focus of activity for the on-going deployment of existing, newly constructed, and upgraded portions of the communications network. Primary NOC planned for HECO, back-up NOC will be at MECO. HELCO will have an entry point to the NOC which will enable them to view their system as needed.
- *Cyber Security:* Cyber Security back-office systems and devices which will provide for secure communications networks within and across all three Companies.

Table 20-28. HECO Telecommunications Project Capital Expenditures and Plant Addition Costs (Millions)

Project	Prior Years	2013	2014	2015	2016	2017	2018	Future Years	Total	In-Service Year
Tiers 1 & 2 (Comm Backbone)			$2.59	$13.09	$13.79	$10.96	$10.67	$28.96	$80.06	
Tier 3 (comm to Distr. Subs, Comm Sites, etc.)			$0.98	$0.46	$0.51	$0.32	$0.62	$29.48	$32.37	
Demand Response ($4M) and Prorated Freq Purchase for DA, DR, SG, AMI Collector points ($600K)			$0.60	$1.00	$1.00	$1.00	$1.00		$4.60	
Tier 4 Collector points for DA, DR, SG, & AMI								$3	$3	
Communications Network Operations Center (NOC)			$1.25	$1.00	$0.25				$2.5	
Cyber Security			$0.50	$0.17	$0.17	$0.17	$0.16	$0.83	$2.00	
Total			*$5.92*	*$15.72*	*$15.72*	*$12.45*	*$12.45*	*$62.27*	*$124.53*	

6.E. Evaluate and Pursue Cost Effective Energy Storage

The Companies are fully committed to achieving a clean energy future. The tremendous growth of intermittent renewable energy resources, primarily wind and photovoltaics (PV), is one of the key drivers for the need to explore operational solutions that maintain grid operability and reliability. The Companies view energy storage as part of a portfolio of potential solutions to manage current and future resources and to help reliably integrate as much renewable energy as possible into the Companies' island grids. The Companies are evaluating energy storage technologies and applications in parallel with ongoing investigations of increasing the operational flexibility of its generating units, development of planning and operational tools, and development of demand response (DR) programs. These paralleled efforts are aimed at evaluating and deploying the correct set of reliable and cost-effective solutions that can help the Companies achieve its clean energy goals.

Action Plan (2014–2018)

Hawaiian Electric's Action Plan for energy storage over the next five years (2014–2018) consists of three primary components:

1. Develop and deploy utility-owned and -operated energy storage project.
2. Assess and track energy storage technologies and applications.
3. Conduct energy storage research and demonstration projects.

The Action Plan is consistent with the prudent activities the Companies are currently engaged in, and pursues commercial deployment of utility-operated energy storage as defined by due diligence of technical and business case evaluations.

Develop and deploy utility-owned and -operated energy storage project.

Due to the increasing growth in intermittent renewable energy and the associated need to gain operational flexibility, Hawaiian Electric plans to move forward with development of a utility-owned and -operated energy storage project on the island of Oahu in the 2014–2018 Action Plan period should it be shown to provide system-wide operational benefits that bring value to all customers.

The operational need, maturing product development, performance, cost, and utility experience related to energy storage are expected to create a positive value proposition for utility-operated energy storage within the Action Plan time frame. The application (purpose and duty cycle), size, technology, and location of the project will be determined during preliminary design and engineering. The project will be either be centralized (single site), distributed (multiple sites), or a combination of these project types.

For budgetary purposes, a centralized 10 MW/15 MWh BESS operated by Hawaiian Electric is assumed for this preliminary Action Plan. The scope of the utility-owned BESS project includes design, engineering, competitive solicitation of a turn-key project, land acquisition, permitting and approvals (including State of Hawaii Public Utilities Commission (PUC) approval), construction, and commissioning.

To execute this Action Plan task, the following preliminary milestone schedule has been identified:

Complete preliminary design and engineering	2Q2014
Release Request for Proposals for turn-key BESS project	2Q2014
Execute turn-key BESS project contract	4Q2014
File G.O. 7 application with the PUC	4Q2014
Complete final turn-key BESS design and engineering	3Q2015
Receive PUC approval	4Q2015
Receive permits and approvals	1Q2016
Complete construction and installation	4Q2016
Complete commissioning, start of commercial operation	1Q 2017

Using the Unit Information Form (UIF) as a basis for BESS equipment cost and cost estimates from Hawaiian Electric project experience, the project budget for a 10 MW/15 MWh BESS is estimated to be about $34.1 million over the 5-year Action Plan period (2014–2018). The breakout of the BESS project budget by year in 2014–2018 is provided in Table 20-29 (in $000).

Table 20-29. HECO Energy Storage Project Capital Expenditures and Plant Addition Costs (Millions)

Project	Prior Years	2013	2014	2015	2016	2017	2018	Future Years	Total	In-Service Year
AFUDC	-	$0.7	$15	$153	$948	-	-	-	$1,117	
Labor	-	$25	$126	$175	$185	$18	-	-	$529	
Materials	-	-	-	-	$22,000	-	-	-	$22,000	
Outside Services	-	-	$100	$1,650	$2,400	-	-	-	$4,150	
Overheads	-	$18	$114	$240	$3,623	$40	-	-	$4,035	
Other (land)	-	-	-	$2,284	-	-	-	-	$2,284	
Total	*$0*	*$44*	*$355*	*$4,502*	*$29,156*	*$58*	*$0*	*$0*	*$34,115*	*2017*

The capital budget estimate described in the above table represents a preliminary, high-level cost estimate, and includes costs for design and engineering BESS[154], materials, and hardware, site preparation, construction materials, and labor, and land purchase of two acres of land in 2015.

The aforementioned scope, schedule, and budget are preliminary, high-level estimates and are expected to change as further project development work is conducted.

Alternative business models that provide Hawaiian Electric, and its customers, with a reduced-risk business arrangement will also be explored. One example is a build, operate, and transfer (BOT) arrangement whereby

[154] Based on "Battery Energy Storage System (BESS) Unit Information Form (UIF), HECO IRP, Table I-1.

the BESS is operated by a third party for a specified period of time until performance milestones are achieved prior to ownership transfer to Hawaiian Electric.

Conduct energy storage research and demonstration projects.

Due to technology risks and evolving business cases for energy storage, the Companies have taken a measured approach in evaluating the performance and cost of energy storage technologies. To offset the technical and business risks, the Companies are engaged in collaborative opportunities with outside entities. Here is a summary of the Companies' current energy storage activities:

- Hawaiian Electric is working with HNEI to test the ability of a HNEI-purchased (via federal grant) 1 MW/250 kWh fast-response lithium titanate BESS to help smooth power fluctuations and regulate voltage on a feeder with high distributed PV penetration on the island of Oahu. The BESS will be located at the Campbell Industrial Park (CIP) Power Generating Station and interconnected to a high PV penetration distribution circuit. Design and engineering is ongoing with commissioning targeted for 1Q 2014. Testing and evaluation at CIP will continue through 2016. Redeployment of the BESS at another utility site after 2016 will be evaluated in the mid-2015 time frame.
- Hawaiian Electric is working with the University of Hawaii's College of Engineering (COE) and HNEI to install an advanced PV inverter with integrated battery storage at the COE's Holmes Hall building. Utilizing EPRI funding, an advanced inverter/battery will replace the existing inverter connected to a 5-kW PV array. The objective is to evaluate the capabilities of a residential-scale, customer-sited inverter to manage PV output. The project will enhance the research and engineering curriculum at COE by enabling participation by COE and HNEI research staff and students. Installation is anticipated for 3Q 2013. The project is expected to serve as a test platform for use by the University of Hawaii and Hawaiian Electric well beyond 2018 with the testing of other advanced inverter, energy storage, and other technologies.
- Hawaiian Electric is currently evaluating a 6 kW/20 kWh lithium ion distributed BESS mated to a 2 kW PV system at Hawaiian Electric's Ward Ave. facility to assess the operation of an integrated PV-battery-electric vehicle (EV) charging station. This carport-of-the-future was commissioned in June 2011 and will continue to be evaluated in the Action Plan period.
- Hawaiian Electric is planning to re-scope a capital project originally intended to be the first research and demonstration project associated with the PV Host program.[155] Hawaiian Electric will investigate the merits of deploying a pilot installation of a utility-operated distributed BESS at a strategic location on a distribution feeder. The purpose of this project is to

[155] Per Order No. 30139 of Docket No. 2009-0098, the PUC approved Hawaiian Electric's withdrawal of its PV Host Program application on January 26, 2012

evaluate whether a small, strategically-located, distribution-level BESS is a technically feasible and cost-competitive utility solution to allow more PV on a distribution circuit. Installation is targeted for 1Q 2015.

The Companies are following a broad-based application strategy to evaluate the merits of energy storage. The applications of the Companies' energy storage research and demonstration projects were purposely varied to enable investigation of various operational issues. For example, BESS projects were sited and developed to address different operational categories such as system-level response to voltage and frequency events, substation-based assets to manage load and impacts of aggregated PV, integrated assets to manage individual IPP PV projects, and mitigation of impacts from customer-sited generation and loads.

The existing BESS demonstration projects are envisioned to continue within the 2014–2018 Action Plan time frame, and in some cases, beyond this period to provide the Companies with operational experience. This experience will be valuable to the Companies in future energy storage planning and operational functions.

Assess and track energy storage technologies and applications.

The Companies continue to assess and track energy storage technologies and demonstration projects through technical evaluations, site visits, direct communications and technical briefings with vendors, electric utility interactions, and its Electric Power Research Institute (EPRI) membership. To date, the Companies have met with over thirty (30) energy storage manufacturers, inverter manufacturers, and system integrators. The Companies also increase its knowledge base through interactions with independent power producers (IPPs) and associated project partners that sell renewable energy to the Companies from generation projects that utilize battery energy storage systems (BESS) to meet performance requirements under power purchase agreements (PPAs). Utility-scale BESS projects have been installed at two wind farms on Maui, one PV project on Lanai, and one wind farm on Oahu (not currently operational due to a fire event in Aug. 2012). The Companies continue to monitor the BESS procurement and operating activities by Kauai Island Utility Cooperative (KIUC) to manage the impacts of large PV installations on the island of Kauai.

The Companies will continue to assess energy storage technologies throughout the 5-year Action Plan period to keep abreast of commercial and emerging technologies, application by electric utilities, and advancements in the energy storage industry.

Hawaiian Electric intends to execute all three components of its energy storage Action Plan over the next five years. The estimated capital budget of Hawaiian Electric's energy storage Action Plan in 2014–2018 is summarized in Table 20-30 (in $000). Note that Hawaiian Electric labor costs for tasks performed as part of their normal business responsibilities (for example, technology tracking and project evaluations) are not included.

Table 20-30. HECO BESS Demonstration Project Capital Expenditures and Plant Addition Costs ($000)

Project	Prior Years	2013	2014	2015	2016	2017	2018	Future Years	Total	In-Service Year
CIP BESS demonstration project	$365	$672	$940						$1,977	2014
UH COE inverter/BESS R&D project										2013
EV fast charger/BESS project										2014
Distributed BESS pilot project			$413	$299					$712	2015
Utility-owned BESS project		$44	$355	$4,502	$29,156	$58			$34,115	2017
Total	*$365*	*$716*	*$1,708*	*$4,801*	*$29,156*	*$58*			*$36,804*	

Costs for the CIP BESS demonstration project include design and engineering expenses in 2013, and materials, installation and commissioning expenses in 2014. Maintenance costs and general liability insurance premiums in 2014–2018 are not reflected in the table. Estimated costs for the distributed BESS pilot project include expenses for design/engineering in 2014 and BESS equipment and installation in 2015. Maintenance and communications expenses in 2015–2018 are not reflected in the table. The actual schedule of these milestones may be revised based on further project development activities.

Hawaiian Electric is committed to be more aggressive in the adoption of advanced commercial-ready technologies to meet evolving grid requirements and customer expectations. The ultimate goal is to increase customer value by deploying grid technologies, such as energy storage, that can increase the production and utilization of safe, reliable, and cost-competitive clean energy.

6.F. Airport Dispatchable Standby Generation

The Airport Dispatchable Standby Generation Project (Airport DSG) will install utility-owned equipment to dispatch standby biofuel-fired reciprocating engines owned by the State Department of Transportation, Airports Division, (DOTA) housed in their Emergency Power Facility (EPF) at the Honolulu International Airport (Airport). These generators will serve dual purposes as emergency generators for the Airport and as limited duty distributed generating units for utility purposes. The EPF is under construction with a projected in-service date of November 2013. However, the project may go into service in 1Q 2014 depending on the State's ability to re-design their SCADA system.

The EPF contains four (4), 2.5 MW biodiesel-fueled quick-start generating units and is sited next to Hawaiian Electric's Airport Substation. In order to minimize engine wear, Hawaiian Electric will dispatch the generators on biodiesel at the continuous run rating of 2 MW for a total facility capacity of 8 MW.

The primary purpose of the EPF is to provide emergency power to prioritized Airport electrical loads within five minutes of a utility grid outage. During non-emergencies, Hawaiian Electric will dispatch the generation capacity for up to 1,500 run hours per year to meet utility operational needs. The electricity generated by the Airport DSG facility is considered as utility power since Hawaiian Electric is providing the fuel and reimbursing maintenance expenses for the facility.

Approximately $421,000 of capital expenditures are forecasted for this project in 2014. The DOTA and Hawaiian Electric will continue to work on making the EPF fully functional as an emergency power plant in 2014 even though the project is anticipated to be useful to Hawaiian Electric in November 2013. This schedule for emergency operation of the EPF by DOTA is dictated by the schedule for electrical upgrades at the Airport vaults.

Hawaiian Electric will procure and deliver the biofuel for the Airport DSG units. The fuel expenses will be recovered through the Energy Cost Adjustment Clause (ECAC) tariff.

Fairness

7. Address Questions with Existing Distributed Generation Programs

7.A. Standardize Interconnection

Purpose: To standardize interconnection process and practices at HECO, HELCO, and MECO, and to implement in a fair and efficient manner for customers.

Scope: The Companies will collaborate to ensure consistent utilization of Rule 14H and adopt best practices to streamline processes. The Companies will support future Commission reviews of its interconnection tariffs to further improve on their fairness, such as reviewing whether the current "first-come, first-served" interconnection approach best serves the interests of all interconnected customers.

To mitigate the cost impact of such studies and upgrades on an individual small customer, the Hawaiian Electric Companies will uniformly adopt the practice of proactively studying and upgrading electric circuits to accommodate multiple PV customers, and will pro-rate the associated study and upgrade costs to customers as they request to install their PV systems. In this manner, costs will be spread across more customers and PV systems will be more efficiently interconnected.

7.B. Implement Technical Solutions for DG

Purpose: To study, develop, and implement technical solutions for high penetration of distributed generation.

Scope: The Companies will collaborate on and standardize technical solutions to mitigate safety and reliability issues associated with high penetration of distributed generation. Where required, proactive cluster studies and system impact studies will be conducted. The Companies will evaluate, demonstrate, and deploy new technologies including those associated with smart grid to upgrade infrastructure to support future interconnecting customers.

7.C. Review Policies

Purpose: Review policies, programs, and rules for best interests of all customers.

Scope: In order to facilitate a fair and continued safe deployment of distributed generation systems, the Companies will review internal policies, Tarff Rules, and programs. Hawaiian Electric will participate in and support

Commission reviews of its interconnection tariffs and energy procurement programs to improve their fairness and effectiveness in acquiring cost-effective clean energy for the benefit of all customers. The Companies will fully participate in Commission-ordered regulatory dockets to review these issues, as was recommended by the RSWG Independent Facilitator.

Table 20-31. HECO Distributed Generation Project Capital Expenditures and Plant Addition Costs (Millions)

Project	2013	2014	2015	2016	2017	2018	Future Years	Total	In-Service Year
Additional Staffing and Consultant Services	$0.5	$2.0	$1.5	$1.0	$1.0	$1.0	$1.0	$8.0	
Software	$0.3	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.6	
Upgrades		$5.0	$5.0	$5.0	$3.0	$2.0	$1.0	$21.0	

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Chapter 21: HELCO Action Plan

The Hawaii Electric Light Action Plan details the specific actions to take to meet energy needs, with an accompanying implementation schedule, over the next five years of our twenty year planning cycle. Putting this plan into effect will meet the energy requirements of the island of Hawaii, the state's largest island.

Implementation of the Action Plan

The energy landscape on the island of Hawaii is complicated and varied. To best meet the broad array of energy needs, the actions the Companies have developed are equally complex. To best show the interrelation of these actions, the Companies have developed flowcharts that show the interactions between and among these actions.

Implementing one action oftentimes affects another action. Understanding the relationship among all of these actions enables the Companies to not only mitigate the downside of taking one action at the expense of another, but also to execute these actions in a way that best meets the current and future energy needs of our customers.

Four Strategic Themes

The Companies have identified future circumstances and developed appropriate actions that can move the Companies toward our goals. These actions are detailed in our Action Plans under four strategic themes:

- Lower customer bills
- Clean energy future
- Modernized grid
- Fairness

The Companies face many challenging issues and uncertainties about a rapidly changing energy environment. Thus, the Companies' IRP report is informative and the Action Plans are clear enough to identify what undertakings (for example, projects, programs, studies) must be done in a structured, proactive manner, while being flexible enough to adapt to an ever-changing future.

Lower Customer Bills

1. Deactivate and Decommission Existing Generation

1.A Decommission of Shipman 3 & 4

Purpose: To deactivate and decommission existing generation.

Scope: Shipman units 3 and 4 are currently on dry layup. The current plan is to decommission Shipman units 3 and 4 after Hu Honua has been in service for a year. To safely decommission Shipman 3 and 4 will require the removal of hazardous materials from the plant. These are typically asbestos, lead, oils etc. Materials will be recycled if practical. Site wells will be secured and closed as well as decontaminated. Project also includes removal of Shipman units 1 and 2, which had previously been retired in place. Deactivation of Shipman has resulted in lower O&M costs.

Table 21-1. HELCO Deactivation Project Capital Expenditures (Millions)

Project	2014	2015	2016	2017	2018
Deactivation of Shipman Units 3 & 4		$2.0	$2.0		

1.B. Deactivate/Decommission additional units as peak load decreases or as new firm renewable generation is added

Scope: Monitor peak load as the future unfolds and deactivate and/or decommission existing generation if capacity is not needed. Addition of new generation such as that from the Geothermal RFP may also result in additional existing generation being deactivated.

1.C. Reactivate generating units if needed for emergencies and/or generation shortfalls

Scope: Monitor peak load and capability of existing generating units as the future unfolds and reactivate generating units if capacity is needed.

2. Lower Cost Generating Facilities

2.A. Geothermal RFP

Purpose: To conduct request for proposals for the supply of up to fifty (50) megawatts of qualified renewable geothermal dispatchable energy and firm capacity resources to lower costs and add to renewable energy portfolio. Results of the current RFP may lead to lower costs than the Strategist input. Interconnection costs will vary based on location and size.

Scope: Milestone schedule laid out in Geothermal RFP as follows.

- Bids: Bids received 4/30/13.
- Award: Selection of final award group, September 2013.
- PPA: Completion of IRS and PPA negotiations, April 2014. Submission of PPA for commission approval, May 2014.
- COD: Target commercial operation date, 2018.

2.B. Repower Waiau Hydro

Purpose: To repower the Waiau Hydro plant to lower costs and add to renewable energy portfolio. Capital investment here will take advantage of a low fuel cost resource.

Scope: Retirement of the 350 kW unit and replace with new 1.2 MW unit. Refurbish 750 kW unit to 800 kW.

- EIS: Requested HECO Project Manager assistance to procure a consultant for EIS development. Schedule subject to change depending on completion of EIS.
- Construction: 2016–2017.
- COD: Target commercial operation date is 2017.

Table 21-2. HELCO Hydro Repower Project Capital Expenditures and Plant Addition Costs (Millions)

Project	2014	2015	2016	2017	2018
Waiau Hydro Repower		$0.6	$4.6	$1.5	

2.C. Evaluate Waste-to-Energy Solutions

Purpose: To work with the County of Hawaii or a private entity on potential options for converting municipal waste to energy. The options are for HELCO to take the waste as a waste or as a Syngas to one of our existing assets.

Scope: A review is in progress to look at the options available for converting waste to a fuel for the Puna or Hill units. The evaluation is looking at technologies as well as the potential benefits to the County in cost reductions for landfill expansions. Plant modifications would occur in 2017–2018 time frame and costs are undetermined at this time.

2.D. Renegotiate Existing IPP Contracts

Purpose: To renegotiate existing contracts that are as-available or firm PPA based on avoided costs. Intent is to decouple these contracts from the oil prices and transition to fixed cost basis to lower costs and reduce price volatility.

Scope: The current discussions are in progress with IPPs with avoided cost-based contracts. There are on-going O&M costs associated with this task.

3. Replace Oil with Biomass and/or LNG

3.A. Evaluate Biomass Conversion of Puna Boiler

Purpose: To convert the existing steam boiler from heavy fuel oil to a woody biomass fuel to lower costs, reduce price volatility and add to renewable energy portfolio.

Scope: Convert the existing oil fired boiler to be able to combust woody biomass which is conveyed pneumatically into the boiler. Includes the fuel receiving, preparation and fuel storage area. The environmental control equipment includes electrostatic precipitator for particulate control and an SCR for control of the NOx emissions. Additional equipment upgrades required are electrical switchgear, boiler tubing, ash removal and control system upgrades to meet NFPA requirements. Target commercial operation date, 2017. A future RFP for fuel resource may lead to lower costs than the Strategist input.

Table 21-3. HELCO Puna Biomass Conversion Project Capital Expenditures and Plant Addition Costs (Millions)

Project	2014	2015	2016	2017	2018
Puna Biomass Conversion		$14.88	$42.91	$31.97	

3.B. Liquefied Natural Gas Switching

Purpose: To reduce HELCO customers' cost of electricity and comply with the requirements of EPA's air regulations, National Ambient Air Quality Standards (NAAQS), by displacing liquid petroleum fuel with Liquefied Natural Gas (LNG). The ability to combust liquid petroleum fuel will be retained to enhance the flexibility and reliability of the units.

Scope: To facilitate development of a bulk LNG import and regasification terminal on Oahu and plan, design, and construct cost-effective modifications to HELCO's generating units to burn natural gas; and distribution of LNG to HELCO.

- Oahu LNG Import and Regasification Terminal: Hawaiian Electric currently anticipates that the terminal will be designed and constructed by another entity and that terminal costs will be included in the cost of the LNG. Hence, Hawaiian Electric does not anticipate making capital expenditures for the LNG Import and Regasification Terminal at this time.
- LNG Supply and Purchase Agreement (SPA): Hawaiian Electric currently anticipates purchasing LNG from an LNG supplier and does not anticipate the need for capital expenditures in the export terminal.
- Distribution of LNG to HELCO: Hawaiian Electric currently envisions LNG being distributed to HELCO's facilities using ISO Containers that are loaded at the Oahu LNG Import and Regasification Terminal and barged to the neighbor islands. Hawaiian Electric anticipates that the cost

of the LNG ISO containers to be included in the shipping cost to HELCO's facilities.

- Modifications to the following generating units to add gas-firing capability: The following units are planned for modification to add gas-firing capability. It should be noted that liquid-fuel firing capability will be retained at all units. Units that are scheduled for either deactivation or decommissioning will not be modified to add gas-firing capability.

  HELCO: Keahole CTs 4, 5 and Hill Unit 6

  Assuming that the LNG Import and Regasification Terminal on Oahu is completed in 2020, the unit modification work for HELCO could start as early as 2018. Engineering will likely start around 2015. If small scale containerized LNG is financially feasible, we will proceed with modifications as soon as PUC approval is received.

- Early small scale containerized LNG distribution, where financially feasible: If LNG can be sourced in small scale and delivered via ISO containers at prices lower than our current petroleum fuel prices and cover the costs of any upgrades required for HELCO's generating units to be able to run on LNG, then portions of the project will be accelerated in advance of the LNG Import Terminal.

Table 21-4. HELCO LNG Project Capital Expenditures and Plant Addition Costs (Millions)

Project	2014	2015	2016	2017	2018
Keahole LNG Infrastructure & Unit Modifications	$0	$0.25	$0.07	$0.04	$0.04
Hill LNG Infrastructure & Unit Modifications	$0	$0.16	$0.05	$0.02	$0.03

4. Other Projects

4.A. Demand Response

Purpose: HELCO's demand response (DR) strategy is to continue to develop a portfolio of residential, commercial and industrial customer loads that will enable reliable and economic operation of Hawaii Island's electric grid.[156] HELCO has been taking steps to implement its DR strategy incrementally, over time, through a combination of shorter-term initiatives including pilot programs, participation in research, development and demonstration (RD&D) projects, and market studies.

HELCO's actions will be framed in terms of a demand response roadmap (DR Roadmap). To develop the HELCO DR Roadmap, HELCO will follow the steps as generally laid out in the Reliability Standards Working Group (RSWG)[157] Demand Side Options Subgroup Whitepaper "*Demand Response as*

[156] See Hawaiian Electric Company, Inc.'s 2013 Annual Program Accomplishments and Surcharge Report (A&S Report), filed March 28, 2011, Docket No. 2007-0341, at 4.

[157] Docket No. 2011-0206.

a Flexible Operating Resource" (RSWG DSO Report),[158] Section III. Pre-Requisites for Demand Response Programs: "The prerequisites for accessing demand response as a resource include a clear system objective and need, loads that are responsive, a control scheme, measurement and verification (and baseline) methodology, and adequate customer/program participant compensation."[159]

Scope: HELCO's five-year Demand Response Action Plan consists of:

- Continue Under Frequency Load Shed (UFLS) and Rider M and Schedule U tariffs.
- Complete and evaluate the results of the DR Potential Study.
- Evaluate Hawaiian Electric and MECO Fast DR Pilot Program for applicability to HELCO's system.
- Evaluate the results of the Hawaiian Electric and MECO GETS studies.
- File applications for feasible and cost-effective DR programs identified during the evaluation process, for approval by the Commission and implement programs. (The costs shown under DR Program are placeholders for costs to be developed once the specific program(s) design is determined and are based upon MECO's estimated costs of rolling out a full-scale program in 2015.)

Demand Response means changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.[160] "The use of loads to provide electric utility services historically provided by generation resources (for example, capacity, energy, and their grid ancillary services) is known as 'demand response.'"[161] Demand Response as described in the RSWG DSO Report may provide HELCO the opportunity to obtain additional operating flexibility.

Of major priority for HELCO is to continue efforts to contain and even reduce the high costs of electric service to its customers. For this reason, HELCO will fully and thoughtfully investigate the necessary technical and operational requirements for DR to be a feasible resource, the cost and rate-impact implications, and the potential benefits of DR for reliability improvement and reduction of revenue requirements compared to current practices and policies. These evaluations will be based on specific models of HELCO operations for (a) peak shifting (steady state) and (b) system balancing and reliability (transient state — Fast DR replacing online reserve and/or acting as circuit level underfrequency load shed).

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[158] The RSWG DSO Report dated December 5, 2012 was filed in the RSWG proceeding, Docket No. 2011-0206.

[159] *Id.*, at 3.

[160] FERC's definition as cited by the Commission in its November 9, 2011 Decision and Order in the Fast DR Pilot Program, Docket 2010-0165.

[161] RSWG DSO Report, at 1.

As HELCO evaluates various types of DR resources, it will also take into account how HELCO's system operation differs from interconnected mainland systems including the minimal use of online contingency reserves, the availability of fast-start generation resources, the use of UFLS, and lack of grid interconnections which requires DR for system balancing to occur in a much shorter time frame than might be required in mainland interconnected systems. HELCO has already integrated clean energy generation to a level exceeding 40% (a large amount of which is variable). To make an analytical evaluation of the cost and technical benefits from DR, the resource potential must be evaluated for the specific functional objective and need. Further, it is paramount that any use of DR on HELCO's system coordinates with and does not jeopardize the existing load-shed system protection scheme which HELCO currently has in place.

DR also offers the potential to reduce excess energy curtailments as one of the potential benefits of peak-shifting DR, shifting loads into periods of low demand to reduce the potential for excess energy and potentially reduce production costs. While HELCO supports examination of load-shifting to quantify potential production cost savings, it should be noted that off-peak curtailments have already been significantly reduced from historical levels by the combined effects of reduction of conventional plant minimums, increased offline cycling, and provision of frequency response from the geothermal facility.

The HELCO DR Roadmap will build upon a foundation of existing DR and load management usage by HELCO. HELCO's DR efforts are described in more detail below:

- Under-frequency load shedding (UFLS). Currently, HELCO uses UFLS to deal with severe ramp-down events. The UFLS strategy works very effectively and inexpensively to accomplish some of the same results as Fast DR. HELCO has for many years successfully utilized under-frequency load-shedding (UFLS) as a very low-cost but effective DR resource. HELCO utilizes the first stage of UFLS in response to loss of generation contingencies in lieu of carrying the contingency reserve online as spinning reserve. This reduces the use of fossil fuel by requiring less online spinning reserve. Unexpected changes in the output of variable-generation units (for example, wind/solar output ramps) are managed using a fleet of fast-starting generators and/or the UFLS for severe ramp events. The fast start generation resources, which are used to restore service after load shed as well as to respond to unanticipated changes in variable generation, can be brought on and loaded in less than one minute for some units and within 2.5 minutes for other units. HELCO also obtains peak shifting from load management through its available tariffs. The Rider M and Schedule U load management rate and rider have helped HELCO over the years to meet its daily system peak load with fewer operating generation units. By the end of 2012, HELCO had in place 33 load management contracts totaling 8,086 kW under Rider M and Schedule U, reducing evening peak by approximately 5,600 kW.

- DR Potential Study. As stated in the RSWG DSO Report, one of the prerequisites for accessing demand response as a resource is to determine whether the size of an available resource can sufficiently provide system benefits. A study will be completed in 2014 will estimate the amount of DR potentially available over the next 20 years. This study will use customer end-use data currently being collected by the Commission's consultant for the Commission's energy efficiency potential study. The customer end-use data is scheduled to be available before the end of 2013.
- HELCO is also currently investigating DR for peak load shifting. As part of production simulation studies being conducted by HELCO's Production Department, one of the objectives included is to determine production cost impacts of DR in steady-state system model frameworks. The tasks under this objective include developing several examples of DR in hour-by-hour format, performing simulation runs to determine the production cost impact of these DR events, and creating a report describing production cost impacts for a range of DR events. HELCO will complete its evaluation of these studies in 2014.
- Fast DR Pilot Program

  HELCO will observe and monitor the progress of the ongoing Fast DR Pilot Programs of Hawaiian Electric and Maui Electric, with the objectives of evaluating (1) the potential for Fast DR on the HELCO system; (2) the applicability of Hawaiian Electric's and Maui Electric's experiences with Fast DR to the HELCO system; and (3) potential problems or complications that HELCO may encounter with Fast DR as a grid management tool. Final evaluations of the Fast DR Pilot Programs are slated to be complete in 2014. Should these evaluations show Fast DR as a feasible and desired resource for the HELCO system, HELCO will file an application for a Fast DR program.

  The Fast DR technologies rely on the availability of existing internet protocol communications infrastructure. In parallel with Fast DR evaluation work, HELCO is currently undertaking the development of communication and control systems appropriate to the large size and geographic challenges of Hawaii Island. In addition, HELCO is preparing to undertake additional modeling studies of Fast DR in a transient system model framework.
- Targeted Market Sectors

  HELCO has approached several targeted sectors, including big box stores and water supply companies, to explore their interests and ability to participate in a DR program. Some interest was expressed but there were concerns regarding their ability to commit to reducing usage on demand as well as the potential costs and benefits. HELCO will continue to work with these customers to explore options to overcome these and other customer concerns, including the design of special customer contracts, and adoption of Hawaiian Electric's successful Technology Assistance/Technology Incentive (TA/TI) approach. To the extent that Hawaiian Electric is able to successfully develop tailored DR options for the Honolulu Board of Water Supply and/or the U.S. Army, HELCO will evaluate and adopt similar approaches working with customers on Hawaii Island.

- Grid Interactive Electric Thermal Storage (GETS). Currently, MECO and Electric Power Research Institute (EPRI) are working together to analyze the potential of Grid Interactive Electric Thermal Storage (GETS) as a DR solution. The objective of the analysis, being performed by EPRI, is to determine if a program utilizing the GETS technology has the potential to improve the integration of as-available generation as well as the required number of controlled water heaters needed to achieve the desired outcome. The results are expected in August 2013. In addition, Hawaiian Electric is also working with EPRI to evaluate potential benefits of the GETS technology by analyzing field data and utility SCADA data together. When completed in 2014, this demonstration project will provide valuable performance data and information related to customer interfacing of grid interactive water heater technology. HELCO will implement its own GETS initiatives to the extent that the MECO and Hawaiian Electric demonstrations show it to be a feasible DR resource for Hawaii Island.

- Evaluate On Bill Financing for DR-Enabled Renewable Energy Generating Devices. The Commission issued Decision and Order No. 30974 in Docket No. 2011-0186 stating "that it is appropriate to require participants that avail themselves of on-bill financing for the use of renewable energy generating devices to participate in available and forthcoming demand response programs and ancillary services programs as a requirement to their use of financed renewable energy generation." The Hawaiian Electric Companies are members of the On Bill Financing Working Group and will assist in identifying technical specifications and DR program design options for renewable generating devices such as solar water heaters and/or photovoltaic systems with a GETS-type DR control.

- Innovation for DR Technologies. HELCO will leverage the information to be compiled by Hawaiian Electric via its Request for Information (RFI) titled, "Innovation for Demand Response Technologies Residential & Small Business Sectors" on newer technologies that offer the potential to supplement and/or replace the deployment of legacy load management devices. The RFI will inform a subsequent request for proposals (RFP) for newer technologies, which Hawaiian Electric plans to issue in the 4Q 2013 – 1Q 2014 time frame.[162]

Future Actions: As described above, if the outcome of the Fast DR pilot, steady-state, transient condition, GETS analysis, or DR potential study, indicate that DR potential exists that is cost-effective, system beneficial and non-disruptive to the existing UFLS, HELCO will move forward with pilot and/or full-scale DR program design, application, and implementation upon Commission approval. Potential pilot programs that HELCO may consider

[162] This assumes that the Commission approves Hawaiian Electric's RDLC Expansion Application in 2013. Without Commission approval, Hawaiian Electric will not have program funds available to conduct an RFP.

include a load shifting pilot program to control water pumping loads and/or a GETS pilot program.

As DR programs are implemented, HELCO will also work to develop an integrated suite of tools and telecommunications infrastructure to enable the effective, reliable, secure and scalable dispatch and management of the DR programs through the development and implementation of a Demand Response Management System (DRMS) and Customer Relationship Management (CRM) system, the planning, mobilization and implementation of a DR Telecommunication Plan, and related cyber security activities.

Table 21-5. HELCO Demand Response Projected Program Expenditures (Millions)

Project	2014	2015	2016	2017	2018	Total
Studies	$0.1	$0.1	$0.1			$0.3
Programs		$0.1	$0.2	$3.2	$2.5	$6.0
Total	*$0.1*	*$0.2*	*$0.3*	*$3.2*	*$2.5*	*$6.3*

4.B. Energy Efficiency

Purpose: While the Companies no longer administer any energy efficiency rebate programs, they remain committed to providing their customers with educational support to manage their electricity bills through energy efficiency and through demand response programs. The Companies also continue to assist in regulatory initiatives that further the objectives of the Hawaii Clean Energy Initiative (HCEI).

Scope: HELCO's five-year energy efficiency action plan consists of the following initiatives:

- Collaborate with Hawaii Energy on responding to customer inquiries regarding Hawaii Energy's energy efficiency programs, providing educational information on energy efficiency and conservation, placing additional focus on low-income customers, and more closely integrating the separate administration of energy efficiency and demand response programs.
- Continue to provide input as members of the Public Benefit Fund Administrator (PBFA) Technical Advisory Group and the Energy Efficiency Portfolio Standards (EEPS) Technical Working Group (EEPS TWG)
- Implement billing, collection, and transmittal of revenues for On-Bill Financing (OBF) and Green Infrastructure.
- Continue to administer the electric vehicle time-of-use pilot rates if granted an extension by the Commission, and
- Implement public electric vehicle charging facility tariffs, including Schedules EV-F and EV-U if approved by the Commission.

On-Bill Financing (OBF)

The Companies are heavily involved in on-going Commission-led efforts to implement OBF by January 2014.[163] OBF has the promise of making energy efficiency measures available to customers without an upfront cost. Repayments can be made over time through the monthly electric bill. The obligation to repay the upfront cost remains with the premise in which the energy efficiency measure is installed, and not the occupant of the premise. Therefore, OBF may be a major step forward in penetrating the rental market.

The Companies are members of the OBF Working Group, co-lead the Utility Integration Subgroup (with Kauai Island Utility Cooperative) and are members of the two remaining subgroups (Program Design and Administration, and Finance Administration).

Green Infrastructure

A Green Infrastructure Program was proposed under SB1087 and was signed into law on June 27, 2013. The Green Infrastructure Program provides for state-issued revenue bonds as an alternative source of capital for OBF. Under the legislation, the Companies would include a non-bypassable Green Infrastructure Fee on all customers' bills that would collect revenues used to repay the bondholders.

PBFA Energy Efficiency Programs

The Companies continue to support Hawaii Energy, the Commission's Public Benefits Fund Administrator (PBFA), by providing customer data that is necessary for the PBFA to assist customers with energy audits and energy efficiency program customer rebates. In addition, both Hawaii Energy and the Hawaiian Electric Companies are moving to collaborate more closely on making energy efficiency more accessible by customers. On January 24, 2013, the Reliability Standards Working Group[164] approved a Demand-side Options Subgroup (DSO) Whitepaper[165] that recommended Hawaii Energy be required to "[W]ork with the utilities to identify those customers and loads that are most promising for demand response, and assure that Hawaii Energy and the DR planners coordinate program plans and marketing to assure that energy efficiency does not compromise promising DR opportunities (and vice versa)". This effort is identified within the Companies' DR action plans.

Educational Resources

The Companies are providing basic educational materials that help them understand and implement energy savings behaviors. Educational outreach to customers includes mobile displays of energy saving information that are

[163] Docket No. 2011-0186, Decision and Order No. 30974, February 1, 2013.

[164] Docket No. 2011-0206.

[165] RSWG Demand-Side Options Subgroup, *Demand Response as a Flexible Operating Resource*, December 5, 2012.

exhibited at community fairs, conferences and public events. Customers that want to participate in Hawaii Energy's customer rebate programs are referred to Hawaii Energy.

4.C. Operational Flexibility Projects

Purpose: To modify the steam units (Hill 5/Hill 6/Puna Steam) and their facilities to implement offline and deep cycling to manage integration of lower cost variable renewable resources.

Scope: Unit projects include:

- Puna offline cycling protection
- Puna condensate upgrades – Dissolved oxygen improvement for deep cycling
- General deep cycling operation improvements – Water chemistry
- Control upgrades for offline and deep cycling operations – Puna
- Control upgrades for offline and deep cycling operations – Hill Unit 5
- Control upgrades for offline and deep cycling operations – Hill Unit 6

Table 21-6. HELCO Operational Flexibility Project Capital Expenditures and Plant Addition Costs (Millions)

Project	2014	2015	2016	2017	2018
Hill 5 Projects	$0.26				
Hill 6 Projects	$0.7				
Puna Steam Projects	$0.625	$0.25			
Production Forecasting	$0.1	$0.1	$0.1	$0.1	$0.1

Clean Energy Future

5. Meet or Exceed RPS

5.A. Implement Approved Reliability Standards Working Group (RSWG) Commitments

Purpose: To implement operational changes to increase the integration of renewable energy into the HELCO grid and lower generation costs.

Scope: As part of the RSWG effort, HELCO committed to certain actions. In general, HELCO will continuously identify new or different ways to lower generation costs and synergies or trade-offs with reliability/security or renewable energy integration. These actions could result in re-optimization of generation commitment and dispatch for energy and ancillary services as new resources become available or relative costs change, implementation of new or changing methods as each system evolves, and/or addition of new cost-effective renewable energy resources to displace fossil generation.

5.B. Biofuel Conversion

Purpose: Utilize biofuels at Keahole Power Plant and/or other possible diesel units to reduce price volatility and add to renewable energy portfolio.

Scope: There are no anticipated equipment modifications required to utilize biofuel at Keahole or other diesel units as it is a drop-in replacement fuel. If that assessment changes in the future, appropriate budget adjustments will occur. The Aina Koa Pono biofuel contract is pending Commission approval.

Modernize Grid

6. Improve Grid Operations

6.A. Energy Delivery

Purpose: To continue plans to meet transmission planning criteria including improvements to cross-island transmission capabilities.

Scope:

- 6200 line relocation: To relocate the 6200 line from Kaumana to Keamuku out of the forest reserve/conservation zone to the highway right-of-way.
- 6800 line reconstruction: To replace existing 69 kV conductors with higher capacity conductors from Keamuku Switching Station to Keahole.
- 3300 line rebuild: To modify 34.5 kV line from Waimea to North Kohala.
- 3400 line rebuild: To modify 34.5 kV line from Keaau to Kilauea.

Table 21-7. HELCO Grid Modernization Project Capital Expenditures and Plant Addition Costs (Millions)

Project	2014	2015	2016	2017	2018
6200 Line Relocation			$0.5	$9.6	$10.5
6800 Line Reconstruction	$6.9	$7.5	$3.4		
3300 Line Rebuild	$3.4	$4.5	$5.6	$5.0	
3400 Line Rebuild	$5.5	$2.6	$2.3		

6.B. Telecommunications

Purpose: To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

Scope: To strategically implement the upgrade of the telecom infrastructure in the following six project categories.

- *Tier 1 & 2 (Infrastructure and Electronics):* Key backbone fiber optic cables, high capacity microwave radios, and high-speed, high-capacity electronic equipment linking and providing service to, critical company sites. Carries data traffic between all areas of the Company, including, but not limited to, all types of SCADA, Business IT LAN, Demand Response, Security Video, Advanced Metering, Mobile Radio, Protective Relaying, and Renewable Integration.

- *Tier 3 (Comm to Distr. Subs, Comm Sites, etc):* Lower capacity, point-to-point communications which connect Distribution Subs, Utility Comm Sites, and other locations into the Tier 1&2 comm backbone. Data transported includes, but is not limited to, Distribution SCADA, IT Hot-spots for Mobile Computing, Demand Response, Security Video, Advanced Metering, and Land Mobile Radio voice trunks.
- *Prorated Frequency Purchase for DA, DR, SG, AMI Collector Points:* Frequencies will need to be purchased for the point-to-point and point-to-multipoint radio links between the Tier 3 sites and the Tier 4 collector points. These radio links will carry the DR, DA, SG, and AMI data to and from the Tier 1 and Tier 2 backbone network. The cost of the frequency purchase is allocated among the Companies.
- *Tier 4 Collector Points for DA, DR, SG, and AMI:* Data Collection systems located throughout the service areas of all three Companies. These collect data from various end-user applications and devices including, but not limited to, Distribution Automation, Mobile Radio, Advanced Meters, EV Charging Stations, etc.
- *Communications Network Operations Center (NOC):* Will monitor the health of the communications systems across all three Companies, and provide the focus of activity for the on-going deployment of existing, newly constructed, and upgraded portions of the communications network. Primary NOC planned for HECO, back-up NOC will be at MECO. HELCO will have an entry point to the NOC which will enable them to view their system as needed.
- *Cyber Security:* Cyber Security back-office systems and devices which will provide for secure communications networks within and across all three Companies.

Table 21-8. HELCO Telecommunications Project Capital Expenditures and Plant Addition Costs (Millions)

Project	Prior Years	2013	2014	2015	2016	2017	2018	Future Years	Total	In-Service Year
Tiers 1 & 2 (Comm Backbone)			$3.506	$5.832	$4.206	$6.177	$6.394	$26.404	$52.519	
Tier 3 (comm to Distr. Subs, Comm Sites, etc.)										
Prorated Freq Purchase for DA, DR, SG, AMI Collector points			$0.2						$0.2	
Tier 4 Collector points for DA, DR, SG, & AMI								$1.0	$1.0	
Communications Network Operations Center (NOC)					$2.5				$2.5	
Cyber Security			$0.25	$0.083	$0.083	$0.083	$0.083	$0.417	$1.0	
Total			*$3.956*	*$5.915*	*$6.790*	*$6.260*	*$6.478*	*$27.821*	*$57.219*	

6.C. Smart Grid

Purpose: To transform the existing grid into a "smarter", more efficient, more reliable grid that integrates more renewable energy through the use of various technologies and capabilities and provide more information and options to customers with the overall goal of reducing costs and improving service to our customers. The initial Smart Grid deployments will be functionally and/or geographically targeted, installing a limited number of advanced grid technology components to obtain and assess some of the high value benefits expected from smart systems. If these targeted deployments are successful in providing the benefits that are anticipated and discussed in the Smart Grid principal issue section, then these programs can be expanded through the action plan period, contingent upon Commission approval.

Scope: The HELCO Smart Grid five-year action plan includes Advanced Metering Infrastructure (AMI) including Conservation Voltage Reduction (CVR) projects and a Pre-Pay program.

AMI

The Company will be updating the AMI business case for full AMI deployment across all three service territories. This update will take advantage of the lessons learned from other utilities that have implemented AMI, identify new capabilities which have been proven at other utilities (such as CVR and Pre-Pay) since the Company's last AMI financial analysis (2008) and business case (2009). The Company will also leverage the information that has been obtained through the Company's interaction with the Electric Power Research Institute (EPRI) and EPRI-member utilities throughout the world. The updated business case, including additional use cases, benefits and functional and technical requirements, will be developed through 2014, followed by a competitive RFP and vendor selection process. The application and approval process with the Commission will follow and run through 2015. Contingent upon Commission approval, AMI implementation is planned to begin in 2016, starting with the deployment of a Meter Data Management System (MDMS) that will be shared by HECO, MECO and HELCO. Meter replacements at HELCO will begin in 2017 (along with related CVR projects and the Pre-Pay program).

Table 21-9. HELCO AMI Project: Operation and Maintenance Costs (Millions)

Project	Prior Years	2014	2015	2016	2017	2018	Future Years	Total	In-Service Year
AMI (HELCO)	$0.084	$0.244	$0.309	$1.875	$9.841	$1.534	$0.000	$13.888	2017

Table 21-10. HELCO AMI Project: Capital and Deferred Costs (Millions)

Project	Prior Years	2014	2015	2016	2017	2018	Future Years	Total	In-Service Year
AMI (HELCO)	$0.000	$0.035	$0.071	$2.960	$21.339	$0.317	$0.000	$24.722	2017

Fairness

7. Address Issues with Existing Distributed Generation Programs

7.A. Standardize Interconnection

Purpose: To standardize interconnection process and practices at HECO, HELCO, and MECO, and to implement in a fair and efficient manner for customers.

Scope: The Companies will collaborate to ensure consistent utilization of Rule 14H and adopt best practices to streamline processes. The Companies will support future Commission reviews of its interconnection tariffs to further improve on their fairness, such as reviewing whether the current "first-come, first-served" interconnection approach best serves the interests of all interconnected customers.

To mitigate the cost impact of such studies and upgrades on an individual small customer, the Hawaiian Electric Companies will uniformly adopt the practice of proactively studying and upgrading electric circuits to accommodate multiple PV customers, and will pro-rate the associated study and upgrade costs to customers as they request to install their PV systems. In this manner, costs will be spread across more customers and PV systems will be more efficiently interconnected.

7.B. Implement Technical Solutions for DG

Purpose: To study, develop, and implement technical solutions for high penetration of distributed generation.

Scope: The Companies will collaborate on and standardize technical solutions to mitigate safety and reliability issues associated with high penetration of distributed generation. Where required, proactive cluster studies and system impact studies will be conducted. The Companies will evaluate, demonstrate, and deploy new technologies including those associated with smart grid to upgrade infrastructure to support future interconnecting customers.

7.C. Review Policies

Purpose: Review policies, programs, and rules for best interests of all customers.

Scope: In order to facilitate a fair and continued safe deployment of distributed generation systems, the Companies will review internal policies, Tarff Rules, and programs. Hawaiian Electric will participate in and support Commission reviews of its interconnection tariffs and energy procurement programs to improve their fairness and effectiveness in acquiring cost-effective clean energy for the benefit of all customers. The Companies will fully participate in Commission-ordered regulatory dockets to review these issues, as was recommended by the RSWG Independent Facilitator.

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Chapter 22:
MECO Action Plan

The Maui Electric Action Plan details the specific actions to take to meet energy needs, with an accompanying implementation schedule, over the next five years of our twenty year planning cycle. Putting this plan into effect will meet the energy requirements of Maui, Lanai, and Molokai.

Implementation of the Action Plan

The energy landscape on the islands of Maui, Molokai, and Lanai is complicated and varied. To best meet the broad array of energy needs, the actions the Companies have developed are equally complex. To best show the interrelation of these actions, the Companies have developed flowcharts that show the interactions between and among these actions.

Implementing one action oftentimes affects another action. Understanding the relationship among all of these actions enables the Companies to not only mitigate the downside of taking one action at the expense of another, but also to execute these actions in a way that best meets the current and future energy needs of our customers. Separate action plans have been created for Maui, Molokai, and Lanai.

Four Strategic Themes

The Companies have identified future circumstances and developed appropriate actions that can move the Companies toward our goals. These actions are detailed in our Action Plans under four strategic themes:

- Lower customer bills
- Clean energy future
- Modernized grid
- Fairness

The Companies face many challenging issues and uncertainties about a rapidly changing energy environment. Thus, the Companies' IRP report is informative and the Action Plans are clear enough to identify what undertakings (for example, projects, programs, studies) must be done in a structured, proactive manner, while being flexible enough to adapt to an ever-changing future.

Lower Customer Bills — Maui

1. Deactivate and Decommission Generation

1.A. Deactivate Kahului Units 1 and 2

Purpose: To deactivate existing generation.

Scope: Kahului Units 1 and 2 will be deactivated in 2014. The engineering and installation of technology to lay up the units will commence immediately. Deactivating units in lieu of decommissioning units allows for the potential reactivation for emergencies and generation shortfalls. On an annual basis, the adequacy of supply for the Maui system will be analyzed. If as a result of the termination of the HC&S power purchase agreement, load growth, natural disaster, or other it is determined that the generating capacity of K1 and/or K2 is needed to meet peak load demand, then K1 and/or K2 will be reactivated and made available for duty.

1.B. Retire Kahului Power Plant (KPP)

Purpose: To integrate more renewable energy which will reduce consumption of fossil fuel, address increasingly stricter environmental regulations, and mitigate the risk of Company-owned generation in the tsunami inundation zone.

Scope: In its planning for the retirement of KPP[166], MECO is looking at a number of alternatives such as demand response, energy storage, assigning capacity value to intermittent renewable resources, and the replacement of old, less efficient generation units with new, quickstarting units. These alternatives are discussed in more detail in the RFP section of this Action Plan. In order to realize the expected benefits, MECO is planning to retire KPP as expeditiously as possible.

In planning and implementing the retirement of KPP, MECO will have to address the following system needs currently fulfilled by KPP. Thus, the estimated retirement date is 2019.

- Adequacy of supply
- Voltage support

[166] Maui Electric Company, Limited's Motion for Partial Reconsideration of Decision and Order No. 31288, Evidentiary Hearing, and Partial Clarification of Decision and Order No. 31288, Docket No. 2011-0092, filed on June 12, 2013, Exhibit B.

Benefits of KPP Retirement

If, even after pursuing capacity alternatives such as DR, energy storage and capacity value to intermittent generation, MECO requires additional generation, it will seek to replace the existing KPP steam units with new, quick-starting units. Quick-starting units will provide offline reserve capacity such that less online regulating reserve will need to be carried. This will enable MECO to integrate increased amounts of renewable energy and potentially reduce fuel costs.

Retiring KPP will allow MECO to avoid possible significant costs to comply with stricter environmental standards. For example, in May 2013, the State of Hawaii Department of Health (DOH) advised MECO of new requirements relating to cooling water discharge at KPP as it relates to its National Pollution Discharge Elimination System (NPDES) permit. The DOH's planned action is similar to permit renewal actions underway for other regulated facilities and MECO is researching the status of those permitting actions. The estimated costs for compliance may be significant and even with substantial investments it is not clear at this time whether MECO would be able to achieve compliance with the new requirements in a timely manner or cost effective manner. While it is expected that there could be significant environmental requirements associated with other alternatives that the Company is considering to replace the generating capacity currently provided by KPP, by retiring KPP in the 2019 time frame, MECO would possibly avoid the significant costs of compliance with NPDES.

Retiring KPP and adding replacement generation to maintain an adequate supply of power for Maui at the already heavy industrial zoned Waena site, will allow some of the island's generation to be outside of the newly redrawn tsunami inundation zones. Refer to 6.F. Tsunami Inundation Zone Protection (page 22-30) in this action plan for further discussion related to the new tsunami inundation zones.

Need for KPP – Adequacy of Supply

MECO's Adequacy of Supply letter was filed with the Commission on January 30, 2013 (January 2013 AOS letter). Based on its June 2012 peak forecast[167], its total firm capacity of 262.3 MW-net, and a reduction in firm capacity by 16 MW at the end of 2014 assuming HC&S no longer provides capacity and energy to MECO, MECO concluded that it expects to have an adequate amount of firm capacity for Maui to meet all reasonably expected demands for service and provide reasonable reserves for emergencies for the period 2012 to 2018, but also anticipated needing additional firm capacity in the 2019 time frame. The retirement of KPP units would increase the amount additional firm capacity needed in the year KPP is retired by 35.9 MW-net.

[167] MECO's June 2012 peak forecast projected gradually increasing peak demand ranging from 192.3 MW-net in 2013 to 204.9 MW-net in 2019.

Need for KPP – Voltage Support

KPP currently provides the 23 kV system with as much as 35.9 MW-net of power, which minimizes the amount of power fed into the 23 kV system from the 69 kV system. When the power provided by KPP is reduced, the 23 kV system becomes heavily dependent on the 69 kV transmission lines and tie transformers. In addition, a reduction of generation from KPP increases Maui system losses. The extra stress on the 69 kV that would result from reduced KPP generation could cause transmission line and tie transformer overloads as well as undervoltage violations across the 23 kV system and parts of the 69 kV system. Undervoltage conditions are such that the voltage at the bus is less than 0.90 PU, per the Company's Transmission Planning Criteria.

On March 11, 2013, MECO submitted its report on "Kahului Power Plant Reduced Operation: Transmission System Impacts and Requirements" in its supplemental response to PUC-IR-15, part d., in this MECO Test Year 2012 Rate Case proceeding. The report provided the findings and conclusions of its analysis and an assessment of the alternatives to operating KPP to provide voltage support and prevent line overloads. The study stated, "The upgrade of the MECO Waiinu-Kanaha 23 kV line to 69 kV (reference Alternative 2) is the lowest cost alternative to meet the goal of operating the Kahului Power Plant (KPP) at reduced output."

Also, the EPS Generation Reserve and Cycling Study was performed in 2012 for MECO to determine, among other things, the number of Kahului units that must operate as a function of the total system demand in order to maintain adequate voltage levels in the Kahului area should certain transmission lines unexpectedly be out of service. The results of its analysis were presented to the Reliability Standards Working Group[168] on January 24, 2013. Although EPS's findings related to voltage support were as follows, they also recommended running at least one large Kahului unit at all times due to lengthy start-up times:

- If the system load level is less than 144 MW, no Kahului generation is required.
- If the system load level is between 144 MW and 175 MW, either one large Kahului unit (Kahului 3 or 4) or two small Kahului units (Kahului 1 and 2) need to be operating.
- If the system load level is between 175 MW and 186 MW, Kahului 3 or 4 needs to be operating.
- If the system load level is between 186 MW and 207 MW, one large Kahului unit (Kahului 3 or 4) and one small Kahului unit (Kahului 1 or 2) need to be operating.
- If the system load level is between 207 MW and 221 MW, one large Kahului unit and both small Kahului units need to be operating.

[168] Formed as part of the Reliability Standards Investigation, in Docket No. 2011-0206.

In 2012, MECO's recorded peak demand on Maui was 194.8 MW-net. The system load was at the following levels in 2012.

Table 22-1. Maui 2012 Load Duration Levels

Load Level	Number of Hours
At or Above 186 MW	7
175 to 186 MW	128
144 to 175 MW	3,291
Below 144 MW	5,358
Total	*8,874*

The level of system demand and the number of hours at the various segments of system demand indicate that KPP is still needed to maintain voltage support on the 23 kV system. As a result, the Waiinu-Kanaha line project and reconductoring is included in this action plan as outlined in the T&D Upgrades section.

1.C. Deactivate or Decommission Additional Units as Peak Load Decreases

Scope: Monitor peak load as the future unfolds and deactivate and/or decommission existing generation if capacity is not needed.

1.D. Reactivate Generating Units If Needed for Emergencies and/or Generation Shortfalls

Scope: Monitor peak load and capability of existing generating units as the future unfolds and reactivate generating units if capacity is needed.

2. Lower-Cost Generating Facilities

2.A. Firm Generation

Purpose: To explore multiple alternatives for balancing generation capability and customer demands.

Scope: The need to add more firm capacity on the system can be triggered by rising peak demand, the loss of firm capacity from the system, or both, since both result in reductions in reserve capacity. Two of the four IRP Scenarios for Maui show an eventual need for additional firm capacity. Additionally, as discussed in the Retirements section of this action plan, the planned retirement of the Kahului Power Plant (KPP) results in a firm capacity need. MECO will pursue the following measures in efforts to defer or reduce the need for new firm capacity:

- *Demand Response (DR) Programs.* DR programs can reduce system demand (and thereby reduce the need for reserve capacity) by (1) automatically separating certain customer loads from the system through underfrequency load shedding, or (2) reducing certain customer loads through utility control with or without a certain amount of notice, or (3) providing economic incentives to customers to reduce consumption during peak times. MECO plans to begin implementation of direct load control pilot programs by the end of 2015 and pursue other DR opportunities as discussed in the Demand Response section of this action plan.

- *Battery Energy Storage System (BESS).* If BESSs can be designed to provide steady output over peak periods under dispatch control by the utility (and recharged in off-peak periods), they can provide firm capacity that would otherwise be provided by conventional generating units. As outlined in the Energy Storage section of this action plan, MECO plans to evaluate the use of a BESS on the Maui system and, if cost effective, proceed with procurement and installation. Currently that the most beneficial use of a BESS on the Maui system appears to be the ability to provide regulating reserve, which will help reduce curtailment of as-available renewable generation. The capacity deferral benefits of a BESS will also be part of the Company's evaluation.
- *Capacity Value of Wind Generation.* There are various probabilistic calculation techniques that can be used to estimate the capacity value of as-available generation. In addition, historical data are used to draw a correlation between the availability of generation from the as-available resources and the periods of peak demand on the system. MECO will continue to collect and analyze hourly power output data from the three wind farms. At this time, MECO is not assigning any capacity value to the wind generation, but as more information is collected and analyzed, MECO expects to assign some capacity value to each wind generation resource. MECO's final report on its assessment of wind capacity value is included in Chapter 15 of this report.

If, even after accounting for any firm capacity contribution of DR, BESS and as-available generation, additional firm capacity is needed to satisfy MECO's capacity planning criteria, MECO will acquire that firm capacity through a Request For Proposal (RFP) in accordance with the Commission's Competitive Bidding Framework. The RFP is planned per the schedule outlined below in parallel to the other initiatives mentioned above.

Table 22-2. MECO Generation RFP Milestones

RFP Milestones	Timing
Develop and issue draft RFP	Q4 2013
PUC approval of RFP	Q1 2014
Issue RFP	Q1 2014
Complete PPA Negotiations	Q4 2015
Submit PPA to PUC	Q4 2015
Commercial Operation	Q1 2019

2.B. Continue Negotiations with HC&S

Purpose: To determine the basis for a potential new or extended power purchase agreement (PPA) with Hawaiian Commercial and Sugar (HC&S) with energy pricing that is lower than and de-linked from the avoided cost in order to lower customer bills.

Scope: MECO is committed to a flexible action plan that includes options to meet its objective of providing safe and reliable energy. MECO and HC&S are engaged in discussions to determine the basis for HC&S to continue providing firm, cost effective, renewable energy to the Maui grid with pricing that is lower than and de-linked from avoided costs.[169]

3. Replace Oil with LNG

3.A. Liquefied Natural Gas Switching

Purpose: To reduce MECO customers' cost of electricity and comply with the requirements of U.S. Environmental Protection Agency's (EPA) air regulations, National Ambient Air Quality Standards (NAAQS), by displacing use of liquid petroleum fuel with Liquefied Natural Gas (LNG). The ability to combust liquid petroleum fuel will be retained to enhance the flexibility and reliability of the units.

Scope: To facilitate development of a bulk LNG import and regasification terminal on Oahu and plan, design, and construct cost effective modifications to MECO's generating units to enable operation with natural gas; and distribution of LNG to MECO.

- *Oahu LNG Import and Regasification Terminal:* Hawaiian Electric currently anticipates that such a terminal will be designed and constructed by another entity and that terminal costs will be included in the cost of the LNG. Hence, Hawaiian Electric does not anticipate making capital expenditures for the LNG Import and Regasification Terminal at this time.
- *LNG Supply and Purchase Agreement (SPA):* Hawaiian Electric currently anticipates purchasing LNG from an LNG supplier and does not anticipate the need for capital expenditures in the export terminal.
- *Distribution of LNG to MECO:* Hawaiian Electric currently envisions LNG being distributed to MECO's facilities using ISO Containers that are loaded at the Oahu LNG Import and Regasification Terminal and barged to the neighbor islands. Hawaiian Electric anticipates that the cost of the LNG ISO containers to be included in the shipping cost to MECO's facilities.
- *Modifications to the certain generating units to add gas-firing capability:* The following units are planned for modification to add gas-firing capability.

[169] MECO and HC&S have agreed not to provide a notice of termination of the PPA such that the PPA could end no sooner than December 31, 2014. The PPA could continue on a year-to-year basis if neither party provides notice of termination of the PPA.

It should be noted that liquid-fuel firing capability will be retained at all units. Units that are scheduled for either deactivation or decommissioning will not be modified to add gas-firing capability.

Maui: Maalaea combustion turbine units 14, 16, 17, 19

Assuming that there are sufficient indications that LNG Import and Regasification Terminal on Oahu is to be completed in 2020, the Company could potentially start modification work for MECO generating units as early as 2018, with engineering starting as early as 2015. If small scale containerized LNG is financially feasible, MECO will proceed with modifications as soon as PUC approval is received.

- *Early small scale containerized LNG distribution, where financially feasible:* If LNG can be sourced in small scale and delivered via ISO containers at prices lower than our current petroleum fuel prices and cover the costs of any upgrades required for MECO's generating units to be able to run on LNG, then portions of the project will be accelerated in advance of the LNG Import Terminal. It is anticipated that Molokai and Lanai are the better candidates for small scale LNG due to the current relatively higher price of fuel for those islands together with the possibility of managing the relatively smaller volume of LNG required using existing shipping schedules.

Table 22-3. Maui LNG Budget (Thousands)

Project	Prior Years	2014	2015	2016	2017	2018	Future Years	Total	In-Service Year
Maalea LNG Infrastructure	$0	$0	$110	$30	$20	$20	$1,090	$1,270	2020
Maalaea 14 Modifications	$0	$0	$70	$20	$10	$10	$730	$840	2020
Maalaea 16 Modifications	$0	$0	$70	$20	$10	$10	$730	$840	2020
Maalaea 17 Modifications	$0	$0	$70	$20	$10	$10	$680	$790	2020
Maalaea 19 Modifications	$0	$0	$70	$20	$10	$10	$680	$790	2020
Total	*$0*	*$0*	*$390*	*$110*	*$60*	*$60*	*$3,910*	*$4,530*	*2020*

4. Other Projects

4.A. Demand Response

Purpose: To develop a portfolio of residential, commercial and industrial customer loads that will enable reliable and economic operation of the Maui grid. MECO will continue to proactively explore opportunities for flexible grid resources to absorb the growth of as-available renewable generation and defer or reduce the size of new capacity additions.

Scope: MECO's demand response (DR) strategy and initiatives are detailed in this DR Action Plan

DR means changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or signal from the utility designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.[170] Utilities have employed DR as system reliability resources to interrupt participant use of power during periods of system management emergencies and/or critical peaks for decades. Such programs allow specific customer loads to serve the interest of all customers by allowing these loads to be controlled to improve grid reliability, reduce capacity shortfalls, and achieve economic savings. However, the utilization of such programs as a tool to support the integration of as-available generation is a new, evolving application of the programs.

MECO recognizes that DR could play a significant role in meeting Hawaii's electric system operational objectives, as stated by the Reliability Standards Working Group (RSWG) Demand Side Options Subgroup:[171]

- Reduce total kWh consumed to reduce oil imports (for example, through efficiency including always-on building commissioning and more efficient, rationalized end-use operation with flatter load factors);
- Reduce peak loads (in the 5–9 PM period) to reduce the amount of fossil generation required for contingencies and demand or PV variability (for example, through lower on-peak air conditioning (AC), water heater, refrigeration and pool pump usage);
- Build off-peak loads to increase consumption of minimum load generation and reduce wind curtailments (for example, through building and device pre-cooling or pre-heating);
- As distributed PV generation and penetration increases on many feeders and expands across the Companies' island grids, reduce the impact of variability and volatility of PV ramps by integrating PV operation with end use loads, offsetting and absorbing much of the fast ramps against host building or same-feeder loads and distributed storage (possibly including end uses as storage media), so the bulk power system sees slower net ramps with less magnitude and speed;
- Use utility-dispatchable and automatic (for example, demand-side equivalent of Automatic Generator Control and frequency droop response), automated load control to deliver fast ancillary services (frequency management, up-regulation and down-regulation, spinning reserve) without burning fossil fuels in a boiler;
- Use utility-dispatchable and automatic, automated load control (responding in the same frequency range as generator governor response and ahead of, but coordinated with, the utility's current under-frequency

[170] FERC's definition as cited in the Commission's Decision and Order issued November 9, 2011, approving the Fast DR Pilot Program, in Docket 2010-0165.

[171] Reliability Standards Working Group (RSWG) Demand Side Options Subgroup Whitepaper "Demand Response as a Flexible Operating Resource" dated December 5, 2012 (RSWG DSO Report), which was approved by the RSWG on January 24, 2013, in Docket No. 2011-0206.

load shedding schemes), and eventually, spinning reserve to protect system frequency;

- Use utility-dispatchable demand response as a bridge under contingency conditions while waiting for utility emergency diesel generators to come on-line.

MECO also recognizes that while DR is only a tool and does not always lower cost or increase renewable energy usage, DR options have the potential to create value for its customers and should be investigated to meet the objectives listed above. Accordingly, MECO will continue to aggressively pursue DR as a potential alternative to delay the addition or reduce the size of new generation as well as the potential to provide regulating reserve and reduce the use of existing conventional generation to lower costs. MECO's current DR efforts are described below:

- *Under-frequency load-shedding (UFLS) and load-shifting Rider M tariff:* MECO has for many years successfully utilized UFLS as a very low-cost but effective DR resource. MECO utilizes the first stage of UFLS in response to loss of generation contingencies in lieu of carrying the contingency reserve online as spinning reserve. This reduces the use of fossil fuel by requiring less online spinning reserve. Unexpected changes in the output of variable-generation units (wind/solar output ramps) are managed using a fleet of fast-starting generators and/or the UFLS for severe ramp events. The fast start generation resources, which are used to restore load shed from generating facilities as well as to respond to unanticipated changes in variable generation, can be brought on and loaded relatively quickly. MECO also obtains peak shifting from load management through its available tariffs. The Rider M load management rate and rider have helped MECO over the years to meet its daily system peak load with fewer operating generation units. At the end of 2012, Maui had in place 10 load management contracts totaling 5,800 kW under Rider M, reducing evening peak by approximately 2,800 kW.

- *Fast DR Pilot Program:*[172] Since November 2011, MECO, together with Hawaiian Electric, has been implementing a pilot program[173] designed to test market acceptance of newer DR technologies and quick response program designs that are intended to provide grid operational benefits for supporting integration of intermittent renewable resources. MECO Fast DR participant loads are controlled on a semi-automated basis with a 10 minute notification by the system operator. In 2012, MECO enrolled three commercial customers in the Fast DR Pilot Program for a total of 150 kW of load. One customer has been commissioned, while the remaining two customers will be commissioned in 2013.

- *DR Potential Study:* As stated in the RSWG DSO Report, one of the prerequisites for accessing DR as a resource is to determine whether the

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[172] The Commission approved the Fast Demand Response Pilot Program by Decision and Order dated November 9, 2011, in Docket No. 2010-0165.

[173] See Docket No. 2010-0165, *Application for Approval of a Fast Demand Response Pilot Program and Recovery of Program Costs*, filed August 31, 2010.

size of an available resource can sufficiently provide system benefits.[174] A study will be completed in 2014 that will estimate the amount of DR potentially available over the next 20 years. This study will use customer end-use data currently being collected by the Commission's consultant for the Commission's energy efficiency potential study. The customer end-use data is scheduled to be available before the end of 2013.

- *Targeted Market Sectors:* MECO has also approached several targeted sectors to explore their interest and ability to participate in DR programs. Water pumping and cold storage customers expressed interest but are concerned with their ability to commit to reducing their usage on demand.
- *Grid Interactive Electric Thermal Storage (GETS):* Currently, MECO and the Electric Power Research Institute (EPRI) are working together to analyze the potential of Grid Interactive Electric Thermal Storage (GETS) as a load management resource. The objective of the analysis is to determine if a program utilizing the GETS technology has the potential to improve the integration of Maui's as-available generation as well as the required number of controlled water heaters needed to achieve the desired outcome. The results are expected in August 2013. If study results show that a reasonable number of GETS systems would have a favorable impact on the integration of as-available generation, a limited field deployment of systems may be implemented.
- *Smart Grid Demonstration Projects:* As a partner on two Smart Grid demonstration projects, MECO expects to leverage the experience and knowledge gained with the implementation of two different load management solutions. The Department of Energy (DOE) funded, HNEI-led Maui Smart Grid Project has enrolled residential customers to participate in a direct load control (DLC) program. The participants elect to have service to their electric water heater or central air-conditioning unit interrupted through a switch or programmable controllable thermostat (PCT). As part of the JUMPSmart project, in collaboration with Japan's New Energy and Industrial Technology Development Organization (NEDO) and Hitachi, electric vehicle chargers are expected to be tested for the ability participate in load control programs.

Future Actions

In the Action Plan period, MECO plans to continue and/or implement the following initiatives:

- Explore other load shifting incentives such as a very low dumped power rate offered to customers to shift customer demand to times when excess renewable energy would otherwise be curtailed.
- Continue to explore demand response opportunities with targeted market sectors.
- Continue Fast DR Pilot Program

[174] See RSWG DSO Report, at 16.

- Continue GETS evaluation and possible field deployments
- Evaluate On Bill Financing for DR-Enabled Renewable Energy Generating Devices
- As DR programs are implemented, MECO will also work to develop an integrated suite of tools and telecommunications infrastructure to enable the effective, reliable, secure and scalable dispatch and management of the DR programs through the development and implementation of a Demand Response Management System (DRMS) and Customer Relationship Management (CRM) system, the planning, mobilization and implementation of a DR Telecommunication Plan, and related cyber security activities.

The Commission issued Decision and Order No. 30974 in Docket No. 2011-0186 stating "that it is appropriate to require participants that avail themselves of on-bill financing for the use of renewable energy generating devices to participate in available and forthcoming demand response programs and ancillary services programs as a requirement to their use of financed renewable energy generation." The Hawaiian Electric Companies are members of the On Bill Financing Working Group and will assist in identifying technical specifications and DR program design options for renewable generating devices such as solar water heaters and/or photovoltaic systems with a GETS-type DR control.

Implement Direct Load Control (DLC) Pilot Programs in 2015

MECO plans to implement residential and commercial pilot DR programs in 2015 to directly control participant appliances or equipment or allow the participant to decide how best to provide the committed reduction in usage. The pilot programs are still being developed, with application for Commission approval planned to be filed in the near future. The programs are expected to be very similar in design to Hawaiian Electric's DLC programs. The key differences between the MECO and Hawaiian Electric programs are: (1) the hosting of the back-office software package by a third party[175] in the MECO program, and (2) the utilization of two-way communication technology.

The pilot program objective will be to gain hands-on experience with a customer-based DR resource that may provide MECO an alternative to new generation as well as the ability to incorporate more as-available renewable resources at lower cost. MECO will analyze cost and operational data utilizing two-way communication technology for the further development of DR programs. Customer acceptance and ability to participate in the DR program offerings will also be evaluated and used to guide future program offerings.

MECO will utilize the most recent experience from the Hawaiian Electric Companies' existing DR programs, Hawaiian Electric's RFI entitled

[175] MECO plans to hire a third party to host (operate and maintain) a back-end software control system which remotely activates/restores load control switches with proprietary coded load shed commands sent through a communication system.

"Innovation for Demand Response Technologies Residential & Small Business Sectors", the Hawaiian Electric Companies smart grid demonstration projects, as well as vendor proposals received in response to the MECO DR RFP, to inform the final pilot program design that will be put forth in the application. Pending refinement and confirmation of program design based on these informative activities, further detail on the pilot program is described below.

Residential Direct Load Control (RDLC) Pilot Program

MECO plans to implement a RDLC pilot program for emergency and economic demand response system benefits. In anticipation of higher peak load, use of the RDLC pilot program resource can also be used as an economic resource to defer or avoid starting additional generation units that would otherwise be needed and, therefore, save on fuel and variable O&M generation costs. MECO envisions the program to initially include approximately 4,400 residential customers on the island of Maui, representing an estimated 2.1 MW in peak demand reduction. Participants in the pilot program will receive the necessary technology (hardware and services) at no cost and an incentive in return for allowing MECO to interrupt service to their electric water heaters and/or to increase the thermostat temperature of their central air conditioning (A/C) systems. The pilot program is envisioned to employ two-way communication technology in order to provide benefits such as visibility of available customer load and validation of load interruption. A customer's load would be curtailed in response to a MECO request, via a third party, sent (emergency or economic dispatch) to load switches or PCTs at participant sites. MECO will expand and modify the design of the program to include additional participants and/or residential customer loads based on pilot program experience and available technology solutions.

Commercial & Industrial Direct Load Control (CIDLC) Pilot Program

MECO also plans to implement a CIDLC pilot program for emergency and economic demand response system benefits. The CIDLC pilot program resource can also be used as an economic resource to defer starting or avoid starting additional generation units that would otherwise be needed and, therefore, save on fuel and variable O&M generation costs. MECO envisions the program to initially target 3.0 MW in peak demand reduction. Enrolled commercial and industrial customers may nominate all or a portion of their electrical load (Controlled Load) to participate in the CIDLC Pilot Program. Controlled Loads may be interrupted automatically by MECO, or manually by the participant, and participants will receive incentives to allow these interruptions. Participants will receive a Load Control Event notification at least one hour prior to each Load Control Event. This will allow participants to interrupt their Controlled Loads: (a) automatically (utilizing a remotely operated relay switch); (b) through a Building Management System (BMS); (c) manually; or (d) through a combination of these options.

Table 22-4. MECO Demand Response Milestones

Demand Response Milestones	Timing
Issue RFP to DR vendors	Q4 2013
Vendor selection and negotiations	Q2 2014
File Commission application	Q3 2014
Begin implementation	Q4 2015
Estimated impacts – 0.7 MW	2016
Estimated impacts – 1.9 MW	2017
Estimated impacts – 3.4 MW	2018
Estimated impacts – 4.0 MW	2019

Table 22-5. MECO Demand Response Budget (Thousands)

Project	2014	2015	2016	2017	2018	Total
Studies and Pilots	$150	$100	$0	$0	$0	$250
Fast DR Pilot Program	$99	$99	$99	$99	$99	$495
RDLC Pilot Program	$0	$1,829	$1,369	$1,499	$1,679	$6,376
CIDLC Pilot Program	$0	$1,228	$1,002	$1,244	$1,317	$4,791

4.B. Energy Efficiency

Purpose: While the Companies no longer administer any energy efficiency rebate programs, they remain committed to providing their customers with educational support to manage their electricity bills through energy efficiency and through demand response programs. The Companies also continue to assist in regulatory initiatives that further the objectives of the Hawaii Clean Energy Initiative (HCEI).

Scope: Maui Electric's five-year energy efficiency action plan consists of the following initiatives:

- Collaborate with Hawaii Energy on responding to customer inquiries regarding Hawaii Energy's energy efficiency programs, providing educational information on energy efficiency and conservation, placing additional focus on low-income customers, and more closely integrating the separate administration of energy efficiency and demand response programs.
- Continue to provide input as members of the Public Benefit Fund Administrator (PBFA) Technical Advisory Group and the Energy Efficiency Portfolio Standards (EEPS) Technical Working Group (EEPS TWG)
- Implement billing, collection, and transmittal of revenues for On-Bill Financing (OBF) and Green Infrastructure.

- Continue to administer the electric vehicle time-of-use pilot rates if granted an extension by the Commission, and
- Implement public electric vehicle charging facility tariffs, including Schedules EV-F and EV-U if approved by the Commission.

On-Bill Financing (OBF)

The Companies are heavily involved in on-going Commission-led efforts to implement OBF by January 2014.[176] OBF has the promise of making energy efficiency measures available to customers without an upfront cost. Repayments can be made over time through the monthly electric bill. The obligation to repay the upfront cost remains with the premise in which the energy efficiency measure is installed, and not the occupant of the premise. Therefore, OBF may be a major step forward in penetrating the rental market.

The Companies are members of the OBF Working Group, co-lead the Utility Integration Subgroup (with Kauai Island Utility Cooperative) and are members of the two remaining subgroups (Program Design and Administration, and Finance Administration).

Green Infrastructure

A Green Infrastructure Program was proposed under SB1087 and was signed into law on June 27, 2013. The Green Infrastructure Program provides for state-issued revenue bonds as an alternative source of capital for OBF. Under the legislation, the Companies would include a non-bypassable Green Infrastructure Fee on all customers' bills that would collect revenues used to repay the bondholders.

PBFA Energy Efficiency Programs

The Companies continue to support Hawaii Energy, the Commission's Public Benefits Fund Administrator (PBFA), by providing customer data that is necessary for the PBFA to assist customers with energy audits and energy efficiency program customer rebates. In addition, both Hawaii Energy and the Hawaiian Electric Companies are moving to collaborate more closely on making energy efficiency more accessible by customers. On January 24, 2013, the Reliability Standards Working Group[177] approved a Demand-Side Options Subgroup (DSO) Whitepaper[178] that recommended Hawaii Energy be required to "[W]ork with the utilities to identify those customers and loads that are most promising for demand response, and assure that Hawaii Energy and the DR planners coordinate program plans and marketing to assure that energy efficiency does not compromise promising DR opportunities (and vice versa)". This effort is identified within the Companies' DR action plans.

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[176] Docket No. 2011-0186, Decision and Order No. 30974, February 1, 2013.

[177] Docket No. 2011-0206.

[178] RSWG Demand-Side Options Subgroup, *Demand Response as a Flexible Operating Resource*, December 5, 2012.

Educational Resources

The Companies are providing basic educational materials that help them understand and implement energy savings behaviors. Educational outreach to customers includes mobile displays of energy saving information that are exhibited at community fairs and public events. The Companies also provide an on-line energy audit for residential customers that give energy conservation and energy efficiency tips to help customers reduce their electrical usage. The on-line Going Solar resource center provides information on solar water heating and other energy efficient technologies. Customers that want to participate in Hawaii Energy's customer rebate programs are referred to Hawaii Energy.

Existing Regulatory Initiatives

The Companies also participate in regulatory initiatives that support energy efficiency. This includes the establishment of tariffs specifically designed to increase the adoption of electric vehicles (EVs).

The Companies are members of the PBFA Technical Advisory Group that provides input into the design, deployment, and evaluation of the PBFA's energy efficiency programs.

The Companies are also members of the EEPS TWG that is charged with coordinating the issues in the EEPS by making recommendations regarding prioritizing savings strategies for the portfolio [of programs and activities], determining eligible measures and programs and revising goals as necessary.[179]

Under the auspices of the EEPS TWG, the Commission initiated activities in 2012 designed to result in a completed energy efficiency potential study for the state in late 2013 or early 2014. The Companies assisted in the development of the mail survey forms, provided the assistance of their key account managers in contacting major customers in their service territories, and provided overall reference sales and market segmentation information to help the Commission with the potential study.

4.C. Low-Cost Biofuels

Purpose: To source low-cost biofuels as a part of the portfolio of renewable energy consistent with the Company's commitment to the Hawaii Clean Energy Initiative and the State's Renewable Portfolio Standards Requirements.

Scope: Biofuels have recently become cost competitive with some high quality petroleum fuels. In fact, biodiesel is a renewable substitute with superior attributes for what is currently the Utilities highest price grade of fossil fuel, Ultra Low Sulfur Diesel (ULSD). Such ULSD is currently supplied primarily on the basis of tanker truck delivery sourced at on-island facilities,

[179] Docket No. 2010-0037, Decision and Order No. 30089, Approving a Framework for Energy Efficiency Portfolio Standards, January 4, 2012, Exhibit A, pages 17–18.

a logistical arrangement entirely consistent with the smaller-scale biofuel producers' processing and distribution capabilities.

Hawaiian Electric is preparing to issue a RFP in 3Q 2013 seeking supplies of ULSD and other petroleum fuels for all of its island Utilities, focused on the procurement of generation fuels for Hawaii Electric Light Company, Inc. (HELCO) and MECO, whose current supply arrangements expire at the end of 2014. This Inter-Island Fuel Supply RFP will offer biofuel suppliers, including but not limited to local biodiesel producers, the opportunity to offer competitively priced supplies of fuel for all or part of the Utility's ULSD required volumes consumed on the Islands of Hawaii, Lanai, Molokai and Maui.

As additional supplies of renewable liquid fuels become increasingly cost effective and more commonly available, through local production or bulk importation, for example, Hawaiian Electric may issue successive renewable fuel RFPs later in the decade for additional amounts of biofuel in order to meet increasingly stringent environmental regulations on engine and boiler emissions or for consumption in the Companies' generating facilities in order to comply with State 2020 and later RPS goals.

Clean Energy Future — Maui

5. Meet or Exceed RPS

5.A. Implement Reliability Standards Working Group (RSWG) Commitments

Purpose: To implement operational changes to increase the integration of renewable energy into the Maui grid and lower generation costs.

Scope: As part of the RSWG effort, MECO committed to certain actions. In general, MECO will continuously identify new or different ways to lower generation costs and synergies or trade-offs with reliability/security or renewable energy integration. These actions could result in re-optimization of generation commitment and dispatch for energy and ancillary services as new resources become available or relative costs change, implementation of new or changing methods as each system evolves, and/or addition of new cost-effective renewable energy resources to displace fossil generation.

As a result of the general commitments and goals defined above, MECO has already identified and is committed to implement some specific actions such as:

- Modifications to Kahului generating units 3 and 4 necessary to:
  - Enable the units to start up in a shorter time frame
  - Lower the minimum operating loads on the units
  - Enable the units to cycle on a daily basis or to be shut down for extended durations (days, weeks, or months) while mitigating any deleterious effects, and maintaining compliance with environmental requirements
- Implement transmission projects to reduce the voltage constraint on the Kahului generating station operations
- Continue improvements to the Automatic Generation Control (AGC) system to allocate the combined cycle steam units contribution to regulation reserves
- Develop unit commitment and dispatch procedures incorporating integrated load and variable generation forecasting and offline cycling decisions

Decisions on whether to make investments in modifications of Kahului Power Plant units will be evaluated in light of the retirement schedule for the plant and impact to customers.

5.B. Maui System Regulating Reserve Policy

Purpose: To reduce curtailment of wind energy

Scope: The existing regulating reserve policy for system operation of the Maui System will immediately be reviewed, with a view to reduce the regulating reserve requirements currently defined for varying levels of wind energy. It is recognized that this may induce some operational risk to the Maui System. Accordingly, operating guidelines for reduced amounts of regulating reserve will be implemented and the effects monitored and evaluated. As necessary and appropriate the regulating reserve requirements will be further refined to mitigate system operational risk or further reduce the curtailment of wind energy.

5.C. Cost-Effective Renewable Energy Projects

Purpose: To integrate cost-effective firm renewable generation.

Scope: Various renewable resources were analyzed under all of the IRP scenarios. Depending on the scenario, geothermal, wind, biofuel, biomass and/or PV were selected by the analysis model as resources in lowest cost resource plans.

MECO will pursue cost-effective firm renewable generation via the firm RFP for Maui as described in 2.A. Firm Generation (page 22-6) of this action plan. In addition, MECO will continue to consider proposals from potential IPPs that could reduce customer bills and increase renewable energy use on the island.

Modernize Grid — Maui

6. Improve Grid Operations

6.A. Transmission and Distribution (T&D) Upgrades

Purpose: To provide safe, reliable power to all MECO customers.

Scope: MECO performs routine maintenance, repair and improvement of its T&D infrastructure. MECO also continually evaluates its T&D system capabilities relative to existing load and anticipated future loads to identify needs for expansion and/or significant upgrades.

As discussed in the Retirements section of the Maui action plan, MECO has also identified the need to upgrade the existing Waiinu–Kanaha 23 kV transmission line to enable retirement of the Kahului Power Plant. A detailed analysis and explanation of the relationship between the Waiinu–Kanaha line project and retirement of KPP was provided in Exhibit B of MECO's Motion for Partial Reconsideration of Decision and Order No. 31288, filed with the commission on June 12, 2013 in Docket No. 2011-0092. In connection with the Waiinu–Kanaha Transmission Line Upgrade project, MECO will also need to reconductor existing transmission lines between (a) the Maalaea Power Plant to Waiinu substation; and (b) Maalaea Power Plant to Puunene substation. MECO is committed to working to complete these projects by December 2018 in order to enable the retirement of KPP in 2019.

Within the Action Plan period, MECO plans the following transmission and distribution projects:

- *Kaonoulu Substation:* Design and construction of a new substation to be located between Maalaea Power Plant and Kihei Substation 35 to accommodate future load growth. Installation of two 10/12.5 MVA transformers, switchgear and related equipment.
- *Kamalii substation and MPP–Kamalii 69kV line:* Development and construction of a new 69kV transmission line and transmission substation to terminate three 69kV lines to accommodate future load growth in South Maui.
- *Waiinu, Kanaha, Kahului substations and Waiinu–Kanaha 69kV line upgrade:* Planning, engineering, and construction to upgrade the existing 23 kV line to a 69 kV transmission line, upgrade related substations, and associated reconductoring work to support the retirement of KPP.
- *Kuihelani Substation:* Installation of associated equipment (a new 10/12.5 MVA, 69-12kV transformer, 12kV switchgear and related equipment).
- *Waena Dispatch Center:* The existing dispatch center at the Kahului Baseyard contains all the critical infrastructure required by the company

for its business operations. This existing center however, is not a hardened site (relative to damage from hurricanes, major storms, etc.) and is located in the Tsunami Inundation Zone. The Waena Center is located out of the Tsunami Inundation Zone and will be built to meet all specifications of a hardened site. This will allow Maui Electric to safely house the critical infrastructure that will be required to restore the system in an expeditious manner in the case of a major emergency.

- *Other distribution projects:* Switchgear and transformer projects; other projects identified by the asset management program
- Other transmission projects: Various other relay upgrades and breaker replacements.
- Other routine T&D maintenance and repair activities

Table 22-6. Maui Transmission and Distribution Action Plan Budget (Thousands)

Project	Prior Years	2014	2015	2016	2017	2018	Total	In-Service Year
Kaonoulu substation	$1,047	$6,496	$7,625	$0	$0	$0	$15,169	2015
Kamalii substation and MPP–Kamalii 69 kV line	$2,035	$1,320	$6,053	$13,156	$10,971	$14	$33,549	2017
Waiinu–Kanaha 69 kV line	$69	$1,119	$999	$1,486	$11,749	$13,283	$28,704	2018
Kuihelani substation	$533	$2,899	$7,084	$7,259	$0	$0	$17,775	2016
Waena Dispatch Center	$0	$0	$0	$0	$7,000	$0	$7,000	2017
Other T&D	n/a	$12,539	$9,930	$8,470	$7,679	$7,141	$45,759	Various
Total	*$3,685*	*$24,373*	*$31,692*	*$30,370*	*$37,399*	*$20,438*	*$147,956*	

6.B. Smart Grid

Purpose: To transform the existing grid into a "smarter", more efficient, more reliable grid that integrates more renewable energy through the use of various technologies and capabilities and provide more information and options to customers with the overall goal of reducing costs and improving service to our customers. The initial Smart Grid deployments will be functionally and/or geographically targeted, installing a limited number of advanced grid technology components to obtain and assess some of the high value benefits expected from smart systems. If these targeted deployments are successful in providing the benefits that are anticipated and discussed in the Smart Grid principal issue section, then these programs can be expanded through the action plan period, contingent upon Commission approval.

Scope: The MECO Smart Grid five-year action plan includes Advanced Metering Infrastructure (AMI) including Conservation Voltage Reduction (CVR) and a Pre-Pay program.

AMI

The Company will be updating the AMI business case for full AMI deployment across all three service territories. This update will take advantage of the lessons learned from other utilities that have implemented AMI, identify new capabilities which have been proven at other utilities (such as CVR and Pre-Pay) since the Company's last AMI financial analysis (2008) and business case (2009). The Company will also leverage the information that has been obtained through the Company's interaction with the Electric Power Research Institute (EPRI) and EPRI-member utilities throughout the world. The updated business case, including additional use cases, benefits and functional and technical requirements, will be developed through 2014, followed by a competitive RFP and vendor selection process. The application and approval process with the Commission will follow and run through 2015. Contingent upon Commission approval, AMI implementation is planned to begin in 2016, starting with the deployment of a Meter Data Management System (MDMS) that will be shared by HECO, MECO and HELCO. Meter replacements at MECO (Maui, Molokai and Lanai) will begin in 2017 (along with related CVR projects and the Pre-Pay program).

Table 22-7. Maui AMI Project Operation and Maintenance Costs (Millions)

Project	Prior Years	2014	2015	2016	2017	2018	Future Years	Total	In-Service Year
AMI (Maui)	$0.068	$0.211	$0.303	$1.875	$8.029	$1.534	$0.000	$12.021	2017

Table 22-8. Maui AMI Project Capital and Deferred Costs (Millions)

Project	Prior Years	2014	2015	2016	2017	2018	Future Years	Total	In-Service Year
AMI (Maui)	$0.000	$0.035	$0.071	$2.406	$16.776	$0.317	$0.000	$19.605	2017

Smart Grid Demonstration Projects

The Companies will continue to implement and support the ongoing smart grid demonstration projects on Maui leveraging outside funding from sources such as the U.S. Department of Energy (DOE) and the New Energy and Industrial Technology Development Organization (NEDO) of Japan. The utilities' role is primarily to provide oversight and project management support in 2014 and 2015 after which the demonstrations will conclude. New systems and capabilities that are developed through these projects will then be assessed to determine if the deployment should be expanded to obtain greater benefits to the system and our customers.

6.C. Telecommunications

Purpose: To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate initiatives such as AMI, Distribution Automation, Smart Grid technologies, and customer programs.

Scope: To strategically implement the upgrade of the telecommunications infrastructure in the following six project categories:

- *Tier 1 & 2 (Infrastructure and Electronics):* Key backbone fiber optic cables, high capacity microwave radios, and high-speed, high-capacity electronic equipment linking and providing service to, critical company sites. Carries data traffic between all areas of the Company, including, but not limited to, all types of Supervisory Control and Data Acquisition (SCADA), Business IT LAN, Demand Response, Security Video, Advanced Metering, Mobile Radio, Protective Relaying, and Renewable Integration.
- *Tier 3 (Communications to Distribution Subs, Communications Sites, etc.):* Lower capacity, point-to-point communications which connect Distribution Subs, Utility Communications Sites, and other locations into the Tier 1&2 communication backbone. Data transported includes, but is not limited to, Distribution SCADA, IT Hot-spots for Mobile Computing, Demand Response, Security Video, Advanced Metering, and Land Mobile Radio voice trunks.
- *Prorated Radio Frequency Purchase for Distribution Automation (DA), DR, Smart Grid (SG), AMI Collector Points:* Frequencies will need to be purchased for the point-to-point and point-to-multipoint radio links between the Tier 3 sites and the Tier 4 collector points. These radio links will carry the DR, DA, SG, and AMI data to and from the Tier 1 and Tier 2 backbone network. The cost of the frequency purchase is allocated among the Companies.
- *Tier 4 Collector Points for DA, DR, SG, and AMI:* Data Collection systems located throughout the service areas of all three Companies. These collect data from various end-user applications and devices including, but not limited to, Distribution Automation, Mobile Radio, Advanced Meters, EV Charging Stations, etc.
- *Communications Network Operations Center (NOC):* Will monitor the health of the communications systems across all three Companies, and provide the focus of activity for the on-going deployment of existing, newly constructed, and upgraded portions of the communications network. Primary NOC planned for HECO, back-up NOC will be at MECO. HELCO will have an entry point to the NOC which will enable them to view their system as needed.
- *Cyber Security:* Cyber Security back-office systems and devices which will provide for secure communications networks within and across all three Companies.

Table 22-9. Maui Telecommunications Master Plan Project Capital Expenditures and Plant Addition Costs (Thousands)

Project	Prior Years	2014	2015	2016	2017	2018	Future Years	Total	In-Service Year
Tiers 1 & 2 (Comm Backbone)	$0	$0	$3,023	$6,433	$5,580	$6,335	$5,825	$27,196	
Tier 3 (Comm to Distr. Subs, Comm Sites, etc.)	$0	$0	$0	$0	$0	$0	$6,441	$6,441	
Prorated Freqency Purchase for DA, DR. SG, AMI Collector Points	$0	$0	$0	$0	$0	$0	$174	$174	
Tier 4 Collector points for DA, DR, SG, & AMI	$0	$0	$0	$0	$0	$0	$870	$870	
Communications Network Operations Center (NOC)	$0	$0	$1,250	$1,250	$0	$0	$0	$2,500	
Cyber Security	$0	$250	$83	$83	$83	$83	$417	$1,000	
Total	*$0*	*$250*	*$4,356*	*$7,767*	*$5,664*	*$6,418*	*$13,726*	*$38,181*	

6.D. Asset Management Plan

Purpose: To optimize T&D asset performance to ensure system reliability, while managing operational and financial risks.

Scope: MECO initiated work to create an Asset Management Program in 2012 to identify and prioritize company assets relative to the T&D electrical system. This involves the development of scenarios and strategies to determine either maintenance or replacement needs of these assets. The objective is to optimize asset performance to ensure system reliability, while managing operational and financial risks.

T&D assets would be prioritized based on impact to reliability indices and financial risks. This initial stage includes building and then managing databases with current asset condition and nameplate information. Strategies would be built around each asset, which would take the assembled databases to come up with replacement forecasts, which would then be translated into an implementation strategy.

While MECO continues to work on the current system data, a consolidated effort is underway to align the Companies in the strategy and organization approach to asset management.

6.E. Energy Storage

Purpose: The Companies are fully committed to achieving a clean energy future. The tremendous growth of intermittent renewable energy resources, primarily wind and PV, is one of the key drivers for the need to explore operational solutions that maintain grid operability and reliability. The Companies view energy storage as part of a portfolio of potential solutions to manage current resources and to help reliably integrate as much renewable energy as possible into the Companies' island grids. The Companies are evaluating energy storage technologies and applications in parallel with ongoing investigations of increasing the operational flexibility of its generating units, decommissioning aging generating units, development of planning and operational tools, development of DR programs, assigning capacity value to intermittent renewable generation resources, and adding new firm renewable generation resources. These parallel efforts are aimed at evaluating and deploying the correct set of reliable and cost-effective solutions to help the Companies achieve its clean energy goals.

Scope: Maui's Action Plan for energy storage over the next five years (2014–2018) consists of three (3) primary components:

1. Develop and deploy utility-scale utility-owned and -operated energy storage project by the end of 2017 if feasible.
2. Conduct energy storage research and demonstration projects.
3. Assess and track energy storage technologies and applications.

1. Develop and deploy utility-owned and -operated energy storage project by the end of 2017 if cost-effective

MECO has conducted several studies that have indicated a BESS may be beneficial for the island of Maui. MECO plans to further evaluate and move forward with development of utility-owned and -operated energy storage project(s) on the island of Maui in the 2014–2018 Action Plan period should a project or projects be shown to be cost-effective and provide system-wide operational benefits that bring value to all customers.

The operational need, maturing product development, performance, cost, and utility experience related to energy storage are expected to create a positive value proposition for utility-operated energy storage within the Action Plan time frame. The application (purpose and duty cycle), size, technology, and location of the project will be determined during preliminary design and engineering. The project will be either centralized (single site), distributed (multiple sites), or a combination of these project types.

For budgetary purposes, a centralized 10 MW/15 MWh BESS operated by MECO is assumed for this preliminary Action Plan. The scope of the utility-owned BESS project includes design, engineering, competitive solicitation of a turn-key project, land acquisition, permitting and approvals (including PUC approval), construction, and commissioning. In addition, MECO has budgeted $250k in each year of the action plan period for utility-owned small-scale distributed energy storage systems to be added to the Maui system based on current system needs and learning from the smart grid projects.

To execute the Action Plan task for a centralized 10MW/15MWh BESS, the following project schedule has been identified:

Complete upgrades to MECO units (K3, M15 and M18)	Q3 2013
Finalize operating practices	Q4 2013
Analyze to determine benefits, size, characteristics	Q2 2014
Develop and issue RFP	Q3 2014
Evaluate responses – decide direction	Q4 2014
If yes: execute turn-key BESS project contract	Q4 2014
File G.O. 7 application with the PUC	Q4 2014
Receive PUC approval	Q4 2015
Complete final turn-key BESS design and engineering	Q1 2016
Receive permits and approvals	Q4 2016
Complete construction and installation	Q2 2017
Complete commissioning, start of commercial operation	Q3 2017

Using the Unit Information Form (UIF) as a basis for BESS equipment cost and cost estimates from Hawaiian Electric project experience, the project budget for a 10 MW/15 MWh BESS is estimated at $34.1 million over the five-year Action Plan period (2014–2018). The breakout of the BESS project budget by year in 2014–2018 is shown in Table 22-10.

Table 22-10. Maui Utility-Owned BESS Project Budget Estimate (Thousands)

Project	Prior Years	2014	2015	2016	2017	2018	Future Years	Total	In-Service Year
AFUDC	–	$0.7	$15	$153	$948	–	–	$1,117	
Labor	–	$25.0	$126	$175	$203	–	–	$529	
Materials	–	–	–	–	$22,000	–	–	$22,000	
Outside Services	–	–	$100	$1,650	$2,400	–	–	$4,150	
Overheads	–	$18.0	$114	$240	$3,663	–	–	$4,035	
Other (Land)	–	–	–	$2,284	–	–	–	$2,284	
Total	*$0*	*$43.7*	*$355*	*$4,502*	*$29,214*	*$0*	*$0*	*$34,115*	*2017*

The capital budget estimate described in Table 22-10 represents a preliminary, high-level cost estimate, and includes costs for design and engineering, BESS[180], materials, and hardware, site preparation, construction materials, and labor, and land purchase of two acres of land in 2016.

[180] Based on "Battery Energy Storage System (BESS) Unit Information Form (UIF)", HECO IRP, Table I-1.

The aforementioned scope, schedule, and budget are preliminary, high-level estimates and are subject to material change as further project development work is conducted.

Alternative business models that provide MECO, and its customers, with a reduced-risk business arrangement will also be explored. One example is a build, operate, and transfer arrangement whereby the BESS is operated by a third party for a specified period of time until performance milestones are achieved prior to ownership transfer to MECO.

Table 22-11. Maui Small-Scale Distributed Energy Storage Systems Budget Estimate (Thousands)

Project	2014	2015	2016	2017	2018	Total
Small Scale Distributed Energy Storage Systems	$250	$250	$250	$250	$250	$1,250

MECO is committed to be more aggressive in the adoption of advanced commercial-ready technologies to meet evolving grid requirements and customer expectations. The ultimate goal is to increase customer value by deploying grid technologies, such as energy storage, that can increase the production and utilization of safe, reliable, and cost-competitive clean energy.

2. Conduct energy storage research and demonstration projects

Due to technology risks and evolving business cases for energy storage, the Companies have taken a measured approach in evaluating the performance and cost of energy storage technologies. To offset the technical and business risks, the Companies are engaged in collaborative opportunities with outside entities. Here is a summary of the MECO's current energy storage activities:

MECO is currently testing potential benefits of two energy storage systems on Maui as part of the on-going Maui smart grid demonstration projects:

- MECO is commissioning a 1 MW/1 MWh lithium ion BESS at its Wailea substation on the island of Maui as part of the DOE-funded, HNEI-led Maui Smart Grid project. The BESS will provide peak circuit load reduction and voltage support. Installation was completed in June 2013.
- MECO is also installing and testing an 18kW/33kWh BESS at its Kahului baseyard.
- Small-scale energy storage systems such as these could be used to provide a demand response function through manual operation or frequency response, provide local voltage/VAR control and/or if aggregated, provide regulating reserve.
- MECO is pursuing a utility-scale BESS project on the island of Molokai in collaboration with HNEI to provide frequency regulation and PV integration support. Terms of the collaboration and preliminary technical assessments continue to be developed. Although a project schedule has

not yet been developed, installation of the BESS is anticipated to occur in 2014.

MECO, in collaboration with Japan's New Energy and Industrial Technology Development Organization (NEDO) and Hitachi, are planning on using both lead–acid and lithium Ion batteries to simulate EV charging on circuits. While not specifically designed to do so, this type of changing can provide insights to load shifting actions performed by a battery. As described in the energy storage action plans for Hawaiian Electric, HELCO, and MECO, the Companies are following a broad-based application strategy to evaluate the merits of energy storage. The applications of the Companies' energy storage research and demonstration projects were purposely varied to enable investigation of various operational issues. For example, BESS projects were sited and developed to address different operational categories such as system-level response to voltage and frequency events, substation-based assets to manage load and impacts of aggregated PV, integrated assets to manage individual IPP PV projects, and mitigation of impacts from customer-sited generation and loads.

The existing BESS demonstration projects are envisioned to continue within the 2014–2018 Action Plan time frame, and in some cases, beyond this period to provide the Companies with operational experience. This experience will be valuable to the Companies in future energy storage planning and operational functions.

3. Assess and track energy storage technologies and applications

The Companies continue to assess and track energy storage technologies and demonstration projects through technical evaluations, site visits, direct communications and technical briefings with vendors, electric utility interactions, and its EPRI membership. To date, the Companies have met with over thirty (30) energy storage manufacturers, inverter manufacturers, and system integrators. The Companies also increase its knowledge base through interactions with IPPs and associated project partners that sell renewable energy to the Companies from generation projects that utilize BESS to meet performance requirements under PPAs. Utility scale BESS projects have been installed at two wind farms on Maui, one PV project on Lanai, and one wind farm on Oahu (not currently operational due to a fire in August 2012). The Companies continue to monitor the BESS procurement and operating activities by Kauai Island Utility Cooperative (KIUC) to manage the impacts of large PV installations in its service territory.

The Companies will continue to assess energy storage technologies throughout the five-year Action Plan period to keep abreast of commercial and emerging technologies, application by electric utilities, and advancements in the energy storage industry.

6.F. Tsunami Inundation Zone Protection

Purpose: To determine potential impact of new tsunami inundation zones on Maalaea Power Plant and take appropriate mitigation measures.

Scope: In 2013, the Civil Defense Agency of Maui County adopted new tsunami inundation maps for the island of Maui. The maps are based on newly-released scientific modeling by the University of Hawaii geophysicists. The modeling takes into account the topography of the ocean floor around the islands of Hawaii and how that would impact a tsunami wave as it reached the shoreline. The new maps envelope the Maalaea power plant (see www.mauicounty.gov/CivilDefense for maps). The new inundation maps indicate a potential need for greater tsunami protection at the Maalaea power plant/switchyard. MECO will perform an engineering analysis to determine possible impacts to the site and appropriate mitigation options. A project is estimated to be completed in 2017.

Table 22-12. Maui Tsunami Inundation Protection Estimates (Thousands)

Project	2014	2015	2016	2017	2018	Total
Tsunami Protection	$518	$97	$6,158	$7,538	$0	$14,312

Fairness — Maui

7. Address Issues with Existing Distributed Generation Programs

7.A. Standardize Interconnection

Purpose: To standardize interconnection process and practices at HECO, HELCO, and MECO, and to implement in a fair and efficient manner for customers.

Scope: The Companies will collaborate to ensure consistent utilization of Rule 14H and adopt best practices to streamline processes. The Companies will support future Commission reviews of its interconnection tariffs to further improve on their fairness, such as reviewing whether the current "first-come, first-served" interconnection approach best serves the interests of all interconnected customers.

To mitigate the cost impact of such studies and upgrades on an individual small customer, the Hawaiian Electric Companies will uniformly adopt the practice of proactively studying and upgrading electric circuits to accommodate multiple PV customers, and will pro-rate the associated study and upgrade costs to customers as they request to install their PV systems. In this manner, costs will be spread across more customers and PV systems will be more efficiently interconnected.

7.B. Implement Technical Solutions for DG

Purpose: To study, develop, and implement technical solutions for high penetration of distributed generation.

Scope: The Companies will collaborate on and standardize technical solutions to mitigate safety and reliability issues associated with high penetration of distributed generation. Where required, proactive cluster studies and system impact studies will be conducted. The Companies will evaluate, demonstrate, and deploy new technologies including those associated with smart grid to upgrade infrastructure to support future interconnecting customers.

7.C. Review Policies

Purpose: Review policies, programs, and rules for best interests of all customers.

Scope: In order to facilitate a fair and continued safe deployment of distributed generation systems, the Companies will review internal policies, Tarff Rules, and programs. Hawaiian Electric will participate in and support Commission reviews of its interconnection tariffs and energy procurement programs to improve their fairness and effectiveness in acquiring cost-effective clean energy for the benefit of all customers. The Companies will fully participate in Commission-ordered regulatory dockets to review these issues, as was recommended by the RSWG Independent Facilitator.

Maui Electric Company — Molokai

Lower Customer Bills — Molokai

1. Replace Oil with LNG

1.A. Liquefied Natural Gas Switching

Purpose: To reduce MECO customers' cost of electricity and comply with the requirements of U.S. Environmental Protection Agency's (EPA) air regulations, National Ambient Air Quality Standards (NAAQS), by displacing use of liquid petroleum fuel with Liquefied Natural Gas (LNG). The ability to combust liquid petroleum fuel will be retained to enhance the flexibility and reliability of the units.

Scope: To facilitate development of a bulk LNG import and regasification terminal on Oahu and plan, design, and construct cost effective modifications to MECO's generating units to enable operation with natural gas; and distribution of LNG to MECO.

- *Oahu LNG Import and Regasification Terminal.* Hawaiian Electric currently anticipates that such a terminal will be designed and constructed by another entity and that terminal costs will be included in the cost of the LNG. Hence, Hawaiian Electric does not anticipate making capital expenditures for the LNG Import and Regasification Terminal at this time.
- *LNG Supply and Purchase Agreement (SPA).* Hawaiian Electric currently anticipates purchasing LNG from an LNG supplier and does not anticipate the need for capital expenditures in the export terminal.
- *Distribution of LNG to Molokai.* Hawaiian Electric currently envisions LNG being distributed to MECO's Palaau power plant on Molokai using ISO Containers that are loaded at the Oahu LNG Import and Regasification Terminal and barged to Molokai. Hawaiian Electric anticipates that the cost of the LNG ISO containers to be included in the shipping cost to MECO's facilities.
- *Modifications to the following generating units to add gas-firing capability.* The following units are planned for modification to add gas-firing capability. It should be noted that liquid-fuel firing capability will be retained at all units.

  Molokai Palaau Units 7–9 (50% due to knock limitations)

Assuming that there are sufficient indications that the LNG Import and Regasification Terminal on Oahu is to be completed in 2020, the Company could potentially start unit modification work for Molokai generating units as early as 2018, with engineering work starting as early as 2015. If small scale containerized LNG is financially feasible, MECO will proceed with modifications as soon as PUC approval is received.

- *Early small scale containerized LNG distribution, where financially feasible.* If LNG can be sourced in small scale and delivered via ISO containers at prices lower than our current petroleum fuel prices and cover the costs of any upgrades required for MECO's Palaau generating units to be able to run on LNG, then the work to enable the generating units on Molokai to run on LNG will be accelerated in advance of the construction of an LNG Import Terminal on Oahu. It is anticipated that Molokai is one of the better candidates for small scale LNG due to the current relatively higher price of fuel for that island together with the possibility of managing the relatively smaller volume of LNG required using existing shipping schedules.

Table 22-13. Molokai LNG Budget (Thousands)

Project	Prior Years	2014	2015	2016	2017	2018	Future Years	Total	In-Service Year
Palaau 7 Modifications	$0	$30	$70	$20	$1,010	$0	$0	$1,130	2017
Palaau 8 Modifications	$0	$30	$70	$20	$1,010	$0	$0	$1,130	2017
Palaau 9 Modifications	$0	$30	$70	$20	$1,010	$0	$0	$1,130	2017
Total	*$0*	*$90*	*$210*	*$60*	*$3,030*	*$0*	*$0*	*$3,390*	*2017*

2. Other Projects

2.A. Energy Efficiency

Purpose: While the Companies no longer administer any energy efficiency rebate programs, they remain committed to providing their customers with educational support to manage their electricity bills through energy efficiency and through demand response programs. The Companies also continue to assist in regulatory initiatives that further the objectives of the Hawaii Clean Energy Initiative (HCEI).

Scope: Maui Electric's five-year energy efficiency action plan consists of the following initiatives:

- Collaborate with Hawaii Energy on responding to customer inquiries regarding Hawaii Energy's energy efficiency programs, providing educational information on energy efficiency and conservation, placing additional focus on low-income customers, and more closely integrating the separate administration of energy efficiency and demand response programs.

- Continue to provide input as members of the Public Benefit Fund Administrator (PBFA) Technical Advisory Group and the Energy Efficiency Portfolio Standards (EEPS) Technical Working Group (EEPS TWG)
- Implement billing, collection, and transmittal of revenues for On-Bill Financing (OBF) and Green Infrastructure.
- Continue to administer the electric vehicle time-of-use pilot rates if granted an extension by the Commission, and
- Implement public electric vehicle charging facility tariffs, including Schedules EV-F and EV-U if approved by the Commission.

On-Bill Financing (OBF)

The Companies are heavily involved in on-going Commission-led efforts to implement OBF by January 2014.[181] OBF has the promise of making energy efficiency measures available to customers without an upfront cost. Repayments can be made over time through the monthly electric bill. The obligation to repay the upfront cost remains with the premise in which the energy efficiency measure is installed, and not the occupant of the premise. Therefore, OBF may be a major step forward in penetrating the rental market.

The Companies are members of the OBF Working Group, co-lead the Utility Integration Subgroup (with Kauai Island Utility Cooperative) and are members of the two remaining subgroups (Program Design and Administration, and Finance Administration).

The Companies maintain that an appropriately designed OBF program can be implemented such that on-going OBF program support from the utilities, the PBFA, and the financial administrator is transparent from the customer's point of view. In this way, OBF can fully achieve its objective of providing energy efficiency opportunities to underserved markets.

Green Infrastructure

A Green Infrastructure Program was proposed under SB1087 and was signed into law on June 27, 2013. The Green Infrastructure Program provides for state-issued revenue bonds as an alternative source of capital for OBF. Under the legislation, the Companies would include a non-bypassable Green Infrastructure Fee on all customers' bills that would collect revenues used to repay the bondholders.

PBFA Energy Efficiency Programs

Under a Commission-approved protective order, the Companies continue to support Hawaii Energy, the Commission's PBFA, by providing customer data to Hawaii Energy that is necessary for the PBFA to assist customers with energy audits and energy efficiency program customer rebates. In

[181] Docket No. 2011-0186, Decision and Order No. 30974, February 1, 2013.

addition, both Hawaii Energy and the Hawaiian Electric Companies are moving to collaborate more closely on making energy efficiency more accessible by customers.

On January 24, 2013, the Reliability Standards Working Group[182] approved a Demand-Side Options Subgroup (DSO) Whitepaper[183] that recommended Hawaii Energy be required to "[W]ork with the utilities to identify those customers and loads that are most promising for demand response, and assure that Hawaii Energy and the DR planners coordinate program plans and marketing to assure that energy efficiency does not compromise promising DR opportunities (and vice versa)". This effort is identified within the Companies' DR action plans.

Educational Resources

The Companies are providing basic educational materials that help them understand and implement energy savings behaviors. Educational outreach to customers includes mobile displays of energy saving information that are exhibited at public events. The Companies also provide an on-line energy audit for residential customers that give energy conservation and energy efficiency tips to help customers reduce their electrical usage. The on-line Going Solar resource center provides information on solar water heating and other energy efficient technologies. Customers that want to participate in Hawaii Energy's customer rebate programs are referred to Hawaii Energy.

Existing Regulatory Initiatives

The Companies also participate in regulatory initiatives that support energy efficiency. This includes the establishment of tariffs specifically designed to increase the adoption of electric vehicles (EVs).

The Companies are members of the PBFA Technical Advisory Group that provides input into the design, deployment, and evaluation of the PBFA's energy efficiency programs.

The Companies are also members of the EEPS TWG that is charged with coordinating the issues in the EEPS by making recommendations regarding prioritizing savings strategies for the portfolio [of programs and activities], determining eligible measures and programs and revising goals as necessary.[184]

Under the auspices of the EEPS TWG, the Commission initiated activities in 2012 designed to result in a completed energy efficiency potential study for the state in late 2013 or early 2014. The Companies assisted in the development of the mail survey forms, provided the assistance of their key account managers in contacting major customers in their service territories,

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[182] Docket No. 2011-0206.

[183] RSWG Demand-Side Options Subgroup, *Demand Response as a Flexible Operating Resource*, December 5, 2012.

[184] Docket No. 2010-0037, Decision and Order No. 30089, Approving a Framework for Energy Efficiency Portfolio Standards, January 4, 2012, Exhibit A, pages 17–18.

and provided overall reference sales and market segmentation information to help the Commission with the potential study.

2.B. Low-Cost Biofuels

Purpose: To source low-cost biofuels as a part of the portfolio of renewable energy consistent with the Company's commitment to the Hawaii Clean Energy Initiative and the State's Renewable Portfolio Standards Requirements.

Scope: Biofuels have recently become cost competitive with some high quality petroleum fuels. In fact, biodiesel is a renewable substitute with superior attributes for what is currently the Utilities highest price grade of fossil fuel, Ultra Low Sulfur Diesel (ULSD). Such ULSD is currently supplied primarily on the basis of tanker truck delivery sourced at on-island facilities, a logistical arrangement entirely consistent with the smaller-scale biofuel producers' processing and distribution capabilities.

Hawaiian Electric is preparing to issue a RFP in 3Q 2013 seeking supplies of ULSD and other petroleum fuels for all of its island Utilities, focused on the procurement of generation fuels for Hawaii Electric Light Company, Inc. (HELCO) and MECO, whose current supply arrangements expire at the end of 2014. This Inter-Island Fuel Supply RFP will offer biofuel suppliers, including but not limited to local biodiesel producers, the opportunity to offer competitively priced supplies of fuel for all or part of the Utility's ULSD required volumes consumed on the Islands of Hawaii, Lanai, Molokai and Maui.

As additional supplies of renewable liquid fuels become increasingly cost effective and more commonly available, through local production or bulk importation, for example, Hawaiian Electric may issue successive renewable fuel RFPs later in the decade for additional amounts of biofuel in order to meet increasingly stringent environmental regulations on engine and boiler emissions or for consumption in the Companies' generating facilities in order to comply with State 2020 and later RPS goals.

Clean Energy Future — Molokai

3. Meet or Exceed RPS

3.A. Cost-Effective Renewable Energy Projects

Purpose: To integrate cost-effective firm renewable generation.

Scope: Various renewable resources were analyzed under all of the IRP scenarios. Depending on the scenario, wave, wind, biofuel, biomass and/or PV were selected by the analysis model as resources in lowest cost resource plans.

As described in Chapter 8 in the "Lanai and Molokai Analysis" section (page 8-24) for the island of Molokai, the IRP analysis suggested that utility-scale PV with battery storage and biomass could potentially reduce costs and increase renewable energy. MECO will conduct a resource assessment and system impact study for a potential biomass resource on Molokai. If the results of the assessment and study suggest that biomass could be a cost-effective resource for Molokai, MECO will engage with the Molokai community to create a plan for further pursuit of a biomass generation resource. Similarly, MECO will conduct an impact assessment for utility scale PV. If the assessment suggests utility-scale PV would be a cost-effective resource for Molokai, MECO will engage with the Molokai community to create a plan for further pursuit of such a resource. In addition, MECO will continue to consider proposals from potential IPPs that could reduce customer bills and increase renewable energy use on the island.

Modernize Grid — Molokai

4. Improve Grid Operations

4.A. Transmission and Distribution (T&D) Upgrades

Purpose: To provide safe, reliable power to all MECO customers.

Scope: MECO performs routine maintenance, repair and improvement of its T&D infrastructure. MECO also continually evaluates its T&D system capabilities relative to existing load and anticipated future loads to identify needs for expansion and/or significant upgrades.

- Within the Action Plan period, MECO plans to conduct upgrades of aging equipment and routine maintenance on the T&D equipment on island of Molokai. Distribution projects include: switchgear and transformer projects; other projects identified by the asset management program
- Transmission projects: Various other relay upgrades and breaker replacements.
- Other routine T&D maintenance and repair activities

Table 22-14. Molokai Transmission and Distribution Action Plan Budget (Thousands)

Project	2014	2015	2016	2017	2018	Total
Other T&D	$850	$850	$850	$850	$850	$4,250

4.B. Smart Grid

Purpose: To transform the existing grid into a “smarter”, more efficient, more reliable grid that integrates more renewable energy through the use of various technologies and capabilities and provide more information and options to customers with the overall goal of reducing costs and improving service to our customers. The initial Smart Grid deployments will be functionally and/or geographically targeted, installing a limited number of advanced grid technology components to obtain and assess some of the high value benefits expected from smart systems. If these targeted deployments are successful in providing the benefits that are anticipated and discussed in the Smart Grid principal issue section, then these programs can be expanded through the action plan period, contingent upon Commission approval.

Scope: The MECO Molokai Smart Grid five-year action plan includes implementation of Advanced Metering Infrastructure (AMI), with an opt-out provision for customers.

AMI

The Company will be updating the AMI business case for full AMI deployment across all three service territories. This update will take advantage of the lessons learned from other utilities that have implemented AMI, identify new capabilities which have been proven at other utilities since the Company's last AMI financial analysis (2008) and business case (2009) and leverage the information that has been obtained through the Companies' interaction with the EPRI and EPRI-member utilities throughout the world. The updated business case, including additional use cases, benefits and functional and technical requirements, will be developed through 2014, followed by a competitive RFP and vendor selection process. The application and approval process with the Commission will follow and run through 2015. Contingent upon Commission approval, AMI implementation is planned to begin in 2016, starting with the deployment of a Meter Data Management System (MDMS) that will be shared by Hawaiian Electric, MECO, and HELCO Meter replacements on Molokai, are estimated to be performed in 2017.

Table 22-15. Molokai AMI Project Operation and Maintenance Costs (Thousands)

Project	Prior Years	2014	2015	2016	2017	2018	Future Years	Total	In-Service Year
AMI (Molokai)	$3	$6	$1	$0	$327	$0	$0	$337	2017

Table 22-16. Molokai AMI Project Capital and Deferred Costs (Thousands)

Project	Prior Years	2014	2015	2016	2017	2018	Future Years	Total	In-Service Year
AMI (Molokai)	$0	$0	$0	$100	$822	$0	$0	$922	2017

4.C. Telecommunications

Purpose: To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate initiatives such as AMI, Smart Grid technologies, and customer programs.

Scope: To strategically implement the upgrade of the telecommunications infrastructure in the following six project categories:

- *Tier 1 & 2 (Infrastructure and Electronics):* Key backbone fiber optic cables, high capacity microwave radios, and high-speed, high-capacity electronic equipment linking and providing service to, critical company sites. Carries data traffic between all areas of the Company, including, but not limited to, all types of Supervisory Control and Data Acquisition (SCADA), Business IT LAN, Demand Response, Security Video, Advanced Metering, Mobile Radio, Protective Relaying, and Renewable Integration.

- *Tier 3 (Communications to Distribution Subs, Communications Sites, etc.):* Lower capacity, point-to-point communications which connect Distribution Substations, Utility Communications Sites, and other locations into the Tier 1&2 communication backbone. Data transported includes, but is not limited to, Distribution SCADA, IT Hot-spots for Mobile Computing, Demand Response, Security Video, Advanced Metering, and Land Mobile Radio voice trunks.

- *Prorated radio frequency purchase for Distribution Automation (DA), DR, Smart Grid (SG), AMI Collector Points:* Frequencies will need to be purchased for the point-to-point and point-to-multipoint radio links between the Tier 3 sites and the Tier 4 collector points. These radio links will carry the DR, DA, SG, and AMI data to and from the Tier 1 and Tier 2 backbone network. The cost of the frequency purchase is allocated amount the Companies.

- *Tier 4 Collector Points for DA, DR, SG, and AMI:* Data Collection systems located throughout the service areas of all three Companies. These collect data from various end-user applications and devices including, but not limited to, Distribution Automation, Mobile Radio, Advanced Meters, EV Charging Stations, etc.

- *Communications Network Operations Center (NOC):* Will monitor the health of the communications systems across all three Companies, and provide the focus of activity for the on-going deployment of existing, newly constructed, and upgraded portions of the communications network. Primary NOC planned for HECO, back-up NOC will be at MECO. HELCO will have an entry point to the NOC which will enable them to view their system as needed.

- *Cyber Security:* Cyber Security back-office systems and devices which will provide for secure communications networks within and across all three Companies.

Table 22-17. Molokai Telecommunications Master Plan Project Capital Expenditures and Plant Addition Costs (Thousands)

Project	Prior Years	2014	2015	2016	2017	2018	Future Years	Total	In-Service Year
Tiers 1 & 2 (Comm Backbone)	$0	$0	$0	$0	$552	$0	$328	$880	2017–2019
Tier 3 (Comm to Distr. Subs, Comm Sites, etc.)	$0	$0	$0	$0	$0	$0	$555	$555	2021–2023
Prorated Freq Purchase for DA, DR. SG, AMI Collector points	$0	$0	$0	$0	$0	$0	$4	$4	
Tier 4 Collector points for DA, DR, SG, & AMI	$0	$0	$0	$0	$0	$0	$20	$20	
Communications Network Operations Center (NOC)	$0	$0	$0	$0	$0	$0	$0	$0	
Cyber Security	$0	$0	$0	$0	$0	$0	$0	Included within projects	
Total	*$0*	*$0*	*$0*	*$0*	*$552*	*$0*	*$907*	*$1,459*	

4.D. Asset Management Plan

Purpose: To optimize T&D asset performance to ensure system reliability, while managing operational and financial risks.

Scope: MECO initiated work to create an Asset Management Program in 2012 to identify and prioritize company assets relative to the T&D electrical system. This involves the development of scenarios and strategies to determine either maintenance or replacement needs of these assets. The objective is to optimize asset performance to ensure system reliability, while managing operational and financial risks.

T&D assets would be prioritized based on impact to reliability indices and financial risks. This initial stage includes building and then managing databases with current asset condition and "nameplate" information. Strategies would be built around each asset, which would take the assembled databases to come up with replacement forecasts, which would then be translated into an implementation strategy.

While MECO continues to work on the current system data, a consolidated effort is underway to align the Companies in the strategy and organization approach to asset management.

4.E. Energy Storage

Purpose: The Companies are fully committed to achieving a clean energy future. The tremendous growth of intermittent renewable energy resources, primarily wind and PV, is one of the key drivers for the need to explore operational solutions that maintain grid operability and reliability. The Companies view energy storage as part of a portfolio of potential solutions to manage current resources and to help reliably integrate as much renewable energy as possible into the Companies' island grids. The Companies are evaluating energy storage technologies and applications in parallel with ongoing investigations of increasing the operational flexibility of its generating units, decommissioning aging generating units, development of planning and operational tools, development of DR programs, assigning capacity value to intermittent renewable generation resources, and adding new firm renewable generation resources. These parallel efforts are aimed at evaluating and deploying the correct set of reliable and cost-effective solutions to help the Companies achieve its clean energy goals.

Scope: Molokai's Action Plan for energy storage over the next five years (2014–2018) consists of three (3) primary components:

1. Develop and deploy utility-owned and -operated energy storage project if feasible.
2. Conduct energy storage research and demonstration projects.
3. Assess and track energy storage technologies and applications.

1. Develop and deploy utility-owned and -operated energy storage project projects if cost-effective

MECO intends to continue to engage the community on potential opportunities to deploy energy storage on the island of Molokai that are in line with the community needs. MECO intends to continue working with HNEI on a storage project for Molokai in order to gain operational experience on how storage can facilitate the integration of small scale intermittent renewable sources on Molokai's small island grid. Currently, the Action Plan budget does not include costs for additional energy storage projects because the benefits from the MECO-HNEI energy storage project are yet to be demonstrated and validated with operational experience. If it is determined that an additional storage project should be pursued within the Action Plan period based on experience with the MECO-HNEI energy storage project and evaluation of cost effectiveness, MECO will pursue an update to the Action Plan to accommodate such a project.

2. Conduct energy storage research and demonstration projects

Due to technology risks and evolving business cases for energy storage, the Companies have taken a measured approach in evaluating the performance and cost of energy storage technologies. To offset the technical and business risks, the Companies are engaged in collaborative opportunities with outside entities. Here is a summary of MECO's current energy storage activities.

MECO is currently testing potential benefits of two energy storage systems on Maui as part of the on-going Maui smart grid demonstration projects:

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MECO is pursuing a utility-scale BESS project on the island of Molokai in collaboration with HNEI to provide frequency regulation and PV integration support. Terms of the collaboration and preliminary technical assessments continue to be developed. Although a project schedule has not yet been developed, installation of the BESS is anticipated to occur in 2014.

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The existing BESS demonstration projects are envisioned to continue within the 2014–2018 Action Plan time frame, and in some cases, beyond this period to provide the Companies with operational experience. This experience will be valuable to the Companies in future energy storage planning and operational functions.

3. Assess and track energy storage technologies and applications

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The Companies will continue to assess energy storage technologies throughout the five-year Action Plan period to keep abreast of commercial and emerging technologies, application by electric utilities, and advancements in the energy storage industry.

Fairness — Molokai

5. Address Issues with Existing Distributed Generation Programs

5.A. Standardize Interconnection

Purpose: To standardize interconnection process and practices at HECO, HELCO, and MECO, and to implement in a fair and efficient manner for customers.

Scope: The Companies will collaborate to ensure consistent utilization of Rule 14H and adopt best practices to streamline processes. The Companies will support future Commission reviews of its interconnection tariffs to further improve on their fairness, such as reviewing whether the current "first-come, first-served" interconnection approach best serves the interests of all interconnected customers.

To mitigate the cost impact of such studies and upgrades on an individual small customer, the Hawaiian Electric Companies will uniformly adopt the practice of proactively studying and upgrading electric circuits to accommodate multiple PV customers, and will pro-rate the associated study and upgrade costs to customers as they request to install their PV systems. In this manner, costs will be spread across more customers and PV systems will be more efficiently interconnected.

5.B. Implement Technical Solutions for DG

Purpose: To study, develop, and implement technical solutions for high penetration of distributed generation.

Scope: The Companies will collaborate on and standardize technical solutions to mitigate safety and reliability issues associated with high penetration of distributed generation. Where required, proactive cluster studies and system impact studies will be conducted. The Companies will evaluate, demonstrate, and deploy new technologies including those associated with smart grid to upgrade infrastructure to support future interconnecting customers.

5.C. Review Policies

Purpose: Review policies, programs, and rules for best interests of all customers.

Scope: In order to facilitate a fair and continued safe deployment of distributed generation systems, the Companies will review internal policies, Tarff Rules, and programs. Hawaiian Electric will participate in and support Commission reviews of its interconnection tariffs and energy procurement programs to improve their fairness and effectiveness in acquiring cost-effective clean energy for the benefit of all customers. The Companies will fully participate in Commission-ordered regulatory dockets to review these issues, as was recommended by the RSWG Independent Facilitator.

Lower Customer Bills — Lanai

1. Replace Oil with LNG

1.A. Liquefied Natural Gas Switching

Purpose: To reduce MECO customers' cost of electricity and comply with the requirements of U.S. Environmental Protection Agency's (EPA) air regulations, Mercury & Air Toxics Standards (MATS) and National Ambient Air Quality Standards (NAAQS), where applicable, by displacing use of liquid petroleum fuel with Liquefied Natural Gas (LNG). The ability to combust liquid petroleum fuel will be retained to enhance the flexibility and reliability of the units.

Scope: To facilitate development of a bulk LNG import and regasification terminal on Oahu and plan, design, and construct cost effective modifications to MECO's generating units to enable operation with natural gas; and distribution of LNG to MECO.

- *Oahu LNG Import and Regasification Terminal.* Hawaiian Electric currently anticipates that the terminal will be designed and constructed by another entity and that terminal costs will be included in the cost of the LNG. Hence, Hawaiian Electric does not anticipate making capital expenditures for the LNG Import and Regasification Terminal at this time.
- *LNG Supply and Purchase Agreement (SPA).* Hawaiian Electric currently anticipates purchasing LNG from an LNG supplier and does not anticipate the need for capital expenditures in the export terminal.
- *Distribution of LNG to Lanai.* Hawaiian Electric currently envisions LNG being distributed to MECO's Miki Basin power plant on Lanai using ISO Containers that are loaded at the Oahu LNG Import and Regasification Terminal and barged to Lanai. Hawaiian Electric anticipates that the cost of the LNG ISO containers to be included in the shipping cost to MECO's facilities.
- *Modifications to the following generating units to add gas-firing capability.* The following units are planned for modification to add gas-firing capability. It should be noted that liquid-fuel firing capability will be retained at all units.

  Lanai Miki Basin Units 7–8 (50% due to knock limitations)

  Assuming that there are sufficient indications that the LNG Import and Regasification Terminal on Oahu is to be completed in 2020, the Company could potentially start unit modification work for Lanai generating units as early as 2018, with engineering work starting as early as 2015. If small scale containerized LNG is financially feasible, MECO will proceed with modifications as soon as PUC approval is received.

- *Early small scale containerized LNG distribution, where financially feasible.* If LNG can be sourced in small scale and delivered via ISO containers at prices lower than our current petroleum fuel prices and cover the costs of any upgrades required for MECO's Miki Basin generating units to be able to run on LNG, then the work to enable generating units on Lanai to run on LNG will be accelerated in advance of the construction of an LNG Import Terminal on Oahu. It is anticipated that Lanai is one of the better candidates for small scale LNG due to the current relatively higher price of fuel for that island together with the possibility of managing the relatively smaller volume of LNG required using existing shipping schedules.

Table 22-18. Lanai LNG Budget (Thousands)

Project	Prior Years	2014	2015	2016	2017	2018	Future Years	Total	In-Service Year
Miki Basin 7 Modifications	$0	$30	$70	$20	$1,010	$0	$0	$1,130	2017
Miki Basin 8 Modifications	$0	$30	$70	$20	$1,010	$0	$0	$1,130	2017
Total	*$0*	*$60*	*$140*	*$40*	*$2,020*	*$0*	*$0*	*$2,260*	*2017*

2. Other Projects

2A. Energy Efficiency

Purpose: While the Companies no longer administer any energy efficiency rebate programs, they remain committed to providing their customers with educational support to manage their electricity bills through energy efficiency and through demand response programs. The Companies also continue to assist in regulatory initiatives that further the objectives of the Hawaii Clean Energy Initiative (HCEI).

Scope: Maui Electric's five-year energy efficiency action plan consists of the following initiatives:

- Collaborate with Hawaii Energy on responding to customer inquiries regarding Hawaii Energy's energy efficiency programs, providing educational information on energy efficiency and conservation, placing additional focus on low-income customers, and more closely integrating the separate administration of energy efficiency and demand response programs.
- Continue to provide input as members of the Public Benefit Fund Administrator (PBFA) Technical Advisory Group and the Energy Efficiency Portfolio Standards (EEPS) Technical Working Group (EEPS TWG)

- Implement billing, collection, and transmittal of revenues for On-Bill Financing (OBF) and Green Infrastructure.
- Continue to administer the electric vehicle time-of-use pilot rates if granted an extension by the Commission, and
- Implement public electric vehicle charging facility tariffs, including Schedules EV-F and EV-U if approved by the Commission.

On-Bill Financing (OBF)

The Companies are heavily involved in on-going Commission-led efforts to implement OBF by January 2014.[185] OBF has the promise of making energy efficiency measures available to customers without an upfront cost. Repayments can be made over time through the monthly electric bill. The obligation to repay the upfront cost remains with the premise in which the energy efficiency measure is installed, and not the occupant of the premise. Therefore, OBF may be a major step forward in penetrating the rental market.

The Companies are members of the OBF Working Group, co-lead the Utility Integration Subgroup (with Kauai Island Utility Cooperative) and are members of the two remaining subgroups (Program Design and Administration, and Finance Administration).

The Companies maintain that an appropriately designed OBF program can be implemented such that on-going OBF program support from the utilities, the PBFA, and the financial administrator is transparent from the customer's point of view. In this way, OBF can fully achieve its objective of providing energy efficiency opportunities to underserved markets.

Green Infrastructure

A Green Infrastructure Program was proposed under SB1087 and was signed into law on June 27, 2013. The Green Infrastructure Program provides for state-issued revenue bonds as an alternative source of capital for OBF. Under the legislation, the Companies would include a non-bypassable Green Infrastructure Fee on all customers' bills that would collect revenues used to repay the bondholders.

PBFA Energy Efficiency Programs

Under a Commission-approved protective order, the Companies continue to support Hawaii Energy, the Commission's PBFA, by providing customer data to Hawaii Energy that is necessary for the PBFA to assist customers with energy audits and energy efficiency program customer rebates. In addition, both Hawaii Energy and the Hawaiian Electric Companies are moving to collaborate more closely on making energy efficiency more accessible by customers.

[185] Docket No. 2011-0186, Decision and Order No. 30974, February 1, 2013.

On January 24, 2013, the Reliability Standards Working Group[186] approved a Demand-Side Options Subgroup (DSO) Whitepaper[187] that recommended Hawaii Energy be required to "[W]ork with the utilities to identify those customers and loads that are most promising for demand response, and assure that Hawaii Energy and the DR planners coordinate program plans and marketing to assure that energy efficiency does not compromise promising DR opportunities (and vice versa)". This effort is identified within the Companies' DR action plans.

Educational Resources

The Companies are providing basic educational materials that help them understand and implement energy savings behaviors. Educational outreach to customers includes mobile displays of energy saving information that are exhibited at public events. The Companies also provide an on-line energy audit for residential customers that give energy conservation and energy efficiency tips to help customers reduce their electrical usage. The on-line Going Solar resource center provides information on solar water heating and other energy efficient technologies. Customers that want to participate in Hawaii Energy's customer rebate programs are referred to Hawaii Energy.

Existing Regulatory Initiatives

The Companies also participate in regulatory initiatives that support energy efficiency. This includes the establishment of tariffs specifically designed to increase the adoption of electric vehicles (EVs).

The Companies are members of the PBFA Technical Advisory Group that provides input into the design, deployment, and evaluation of the PBFA's energy efficiency programs.

The Companies are also members of the EEPS TWG that is charged with coordinating the "issues in the EEPS by making recommendations regarding prioritizing savings strategies for the portfolio [of programs and activities], determining eligible measures and programs and revising goals as necessary."[188]

Under the auspices of the EEPS TWG, the Commission initiated activities in 2012 designed to result in a completed energy efficiency potential study for the state in late 2013 or early 2014. The Companies assisted in the development of the mail survey forms, provided the assistance of their key account managers in contacting major customers in their service territories, and provided overall reference sales and market segmentation information to help the Commission with the potential study.

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[186] Docket No. 2011-0206.

[187] RSWG Demand-Side Options Subgroup, *Demand Response as a Flexible Operating Resource*, December 5, 2012.

[188] Docket No. 2010-0037, Decision and Order No. 30089, Approving a Framework for Energy Efficiency Portfolio Standards, January 4, 2012, Exhibit A, pages 17–18.

2.B. Low-Cost Biofuels

Purpose: To source low-cost biofuels as a part of the portfolio of renewable energy consistent with the Company's commitment to the Hawaii Clean Energy Initiative and the State's Renewable Portfolio Standards Requirements.

Scope: Biofuels have recently become cost competitive with some high quality petroleum fuels. In fact, biodiesel is a renewable substitute with superior attributes for what is currently the Utilities highest price grade of fossil fuel, Ultra Low Sulfur Diesel (ULSD). Such ULSD is currently supplied primarily on the basis of truck tanker delivery transportation sourced at on-island facilities, a logistical arrangement entirely consistent with the smaller-scale biofuel producers' processing and distribution capabilities.

Hawaiian Electric is preparing to issue a RFP in 3Q 2013 seeking supplies of ULSD and other petroleum fuels for all of its island Utilities, focused on the procurement of generation fuels for Hawaii Electric Light Company, Inc. (HELCO) and MECO, whose current supply arrangements expire at the end of 2014. This Inter-Island Fuel Supply RFP will offer biofuel suppliers, including but not limited to local biodiesel producers, the opportunity to offer competitively priced supplies of fuel for all or part of the Utility's ULSD required volumes consumed on the Islands of Hawaii, Lanai, Molokai and Maui.

As additional supplies of renewable liquid fuels become increasingly cost effective and more commonly available, through local production or bulk importation, for example, Hawaiian Electric may issue successive renewable fuel RFPs later in the decade for additional amounts of biofuel in order to meet increasingly stringent environmental regulations on engine and boiler emissions or for consumption in the Companies' generating facilities in order to comply with State 2020 and later RPS goals.

Clean Energy Future — Lanai

3. Meet or Exceed RPS

3.A. Cost-Effective Renewable Energy Projects

Purpose: To integrate cost-effective firm renewable generation.

Scope: Various renewable resources were analyzed under all of the IRP scenarios. Depending on the scenario, wave, wind, biofuel, biomass and/or PV were selected by the analysis model as resources in lowest cost resource plans.

As described in Chapter 8 in the "Lanai and Molokai Analysis" section (page 8-24) for the island of Lanai, the IRP analysis suggested that utility-scale PV with battery storage and biomass could potentially reduce costs and increase renewable energy. Lanai Resorts has publicly stated it is actively evaluating possible renewable energy projects for the island of Lanai. MECO will conduct a resource assessment and system impact study for a potential biomass resource on Lanai as well as an impact assessment for utility scale PV. Concurrently, MECO will continue to communicate and coordinate with Lanai Resorts with respect to its renewable energy plans. If the results of the assessment and studies suggest that biomass and/or utility scale PV could be cost-effective resources for Lanai, MECO will engage with the Lanai community and to create a plan for further pursuit of such a resource. In addition, MECO will continue to consider proposals from potential IPPs that could reduce customer bills and increase renewable energy use on the island.

Modernize Grid — Lanai

4. Improve Grid Operations

4.A. Transmission and Distribution (T&D) Upgrades

Purpose: To provide safe, reliable power to its customers.

Scope: MECO performs routine maintenance, repair and improvement of its T&D infrastructure. MECO also continually evaluates its transmission and distribution system capabilities relative to existing load and anticipated future loads to identify needs for expansion and/or significant upgrades. On the island of Lanai, the system does not include any transmission assets, therefore all assets and projects are designated as distribution.

Within the Action Plan period, MECO plans to conduct upgrades of aging equipment and routine maintenance on the distribution equipment on island of Lanai.

Table 22-19. Lanai Distribution Action Plan Budget (Thousands)

Project	2014	2015	2016	2017	2018	Total
Distribution	$450	$450	$450	$450	$450	$450

4.B. Smart Grid

Purpose: To transform the existing grid into a "smarter", more efficient, more reliable grid that integrates more renewable energy through the use of various technologies and capabilities and provide more information and options to customers with the overall goal of reducing costs and improving service to our customers. The initial Smart Grid deployments will be functionally and/or geographically targeted, installing a limited number of advanced grid technology components to obtain and assess some of the high value benefits expected from smart systems. If these targeted deployments are successful in providing the benefits that are anticipated and discussed in the Smart Grid principal issue section, then these programs can be expanded through the action plan period, contingent upon Commission approval.

Scope: The MECO Lanai Smart Grid five-year action plan includes implementation of Advanced Metering Infrastructure (AMI), with an opt-out provision for customers.

AMI

The Company will be updating the AMI business case for full AMI deployment across all three service territories. This update will take advantage of the lessons learned from other utilities that have implemented AMI, identify new capabilities which have been proven at other utilities since the Company's last AMI financial analysis (2008) and business case (2009) and leverage the information that has been obtained through the Companies' interaction with the EPRI and EPRI-member utilities throughout the world. The updated business case, including additional use cases, benefits and functional and technical requirements, will be developed through 2014, followed by a competitive RFP and vendor selection process. The application and approval process with the Commission will follow and run through 2015. Contingent upon Commission approval, AMI implementation is planned to begin in 2016, starting with the deployment of a Meter Data Management System (MDMS) that will be shared by Hawaiian Electric, MECO and HELCO Meter replacements on Lanai are estimated to be performed in 2017.

Table 22-20. Lanai AMI Project Operation and Maintenance Costs (Thousands)

Project	Prior Years	2014	2015	2016	2017	2018	Future Years	Total	In-Service Year
AMI (Lanai)	$2	$3	$1	$0	$171	$0	$0	$176	2017

Table 22-21. Lanai AMI Project Capital and Deferred Costs (Thousands)

Project	Prior Years	2014	2015	2016	2017	2018	Future Years	Total	In-Service Year
AMI (Lanai)	$0	$0	$0	$52	$431	$0	$0	$484	2017

4.C. Telecommunications

Purpose: To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate initiatives such as AMI, Smart Grid technologies, and customer programs.

Scope: To strategically implement the upgrade of the telecommunications infrastructure in the following six project categories:

- *Tier 1 & 2 (Infrastructure and Electronics):* Key backbone fiber optic cables, high capacity microwave radios, and high-speed, high-capacity electronic equipment linking and providing service to, critical company sites. Carries data traffic between all areas of the Company, including, but not limited to, all types of Supervisory Control and Data Acquisition (SCADA), Business IT LAN, Demand Response, Security Video, Advanced Metering, Mobile Radio, Protective Relaying, and Renewable Integration.
- *Tier 3 (Communications to Distribution Subs, Communications Sites, etc.):* Lower capacity, point-to-point communications which connect Distribution substations, Utility Communications Sites, and other locations into the Tier 1&2 communication backbone. Data transported

includes, but is not limited to, Distribution SCADA, IT Hot-spots for Mobile Computing, Demand Response, Security Video, Advanced Metering, and Land Mobile Radio voice trunks.

- *Prorated radio frequency purchase for Distribution Automation (DA), DR, Smart Grid (SG), AMI Collector Points:* Frequencies will need to be purchased for the point-to-point and point-to-multipoint radio links between the Tier 3 sites and the Tier 4 collector points. These radio links will carry the DR, DA, SG, and AMI data to and from the Tier 1 and Tier 2 backbone network. The cost of the frequency purchase is allocated among the Companies.
- *Tier 4 Collector Points for DA, DR, SG, and AMI:* Data Collection systems located throughout the service areas of all three Companies. These collect data from various end-user applications and devices including, but not limited to, Distribution Automation, Mobile Radio, Advanced Meters, EV Charging Stations, etc.
- *Communications Network Operations Center (NOC):* Will monitor the health of the communications systems across all three Companies, and provide the focus of activity for the on-going deployment of existing, newly constructed, and upgraded portions of the communications network. Primary NOC planned for HECO, back-up NOC will be at MECO. HELCO will have an entry point to the NOC which will enable them to view their system as needed.
- *Cyber Security:* Cyber Security back-office systems and devices which will provide for secure communications networks within and across all three Companies.

Table 22-22. Lanai Telecommunications Master Plan Project Capital Expenditures and Plant Addition Costs (Thousands)

Project	Prior Years	2014	2015	2016	2017	2018	Future Years	Total	In-Service Year
Tiers 1 & 2 (Comm Backbone)	$0	$0	$0	$0	$278	$0	$4,087	$4,365	2017–2022
Tier 3 (Comm to Distr. Subs, Comm Sites, etc.)	$0	$0	$0	$0	$0	$0	$527	$527	2022
Prorated Freq Purchase for DA, DR. SG, AMI Collector points	$0	$0	$0	$0	$0	$0	$22	$22	
Tier 4 Collector points for DA, DR, SG, & AMI	$0	$0	$0	$0	$0	$0	$110	$110	
Communications Network Operations Center (NOC)	$0	$0	$0	$0	$0	$0	$0	$0	
Cyber Security	$0	$0	$0	$0	$0	$0	$0	Included within projects	
Total	*$0*	*$0*	*$0*	*$0*	*$278*	*$0*	*$4,746*	*$5,024*	

4.D. Asset Management Plan

Purpose: To optimize asset performance to ensure system reliability, while managing operational and financial risks.

Scope: MECO initiated work to create an Asset Management Program in 2012 to identify and prioritize company T&D assets relative to the transmission and distribution electrical system. This involves the development of scenarios and strategies to determine either maintenance or replacement needs of these assets. The objective is to optimize asset performance to ensure system reliability, while managing operational and financial risks.

T&D assets would be prioritized based on impact to reliability indices and financial risks. This initial stage includes building and then managing databases with current asset condition and "nameplate" information. Strategies would be built around each asset, which would take the assembled databases to come up with replacement forecasts, which would then be translated into an implementation strategy.

While MECO continues to work on the current system data, a consolidated effort is underway to align the Companies in the strategy and organization approach to asset management.

4.E. Energy Storage

Purpose: The Companies are fully committed to achieving a clean energy future. The tremendous growth of intermittent renewable energy resources, primarily wind and PV, is one of the key drivers for the need to explore operational solutions that maintain grid operability and reliability. The Companies view energy storage as part of a portfolio of potential solutions to manage current resources and to help reliably integrate as much renewable energy as possible into the Companies' island grids. The Companies are evaluating energy storage technologies and applications in parallel with ongoing investigations of increasing the operational flexibility of its generating units, decommissioning aging generating units, development of planning and operational tools, development of demand response (DR) programs, assigning capacity value to intermittent renewable generation resources, and adding new firm renewable generation resources. These parallel efforts are aimed at evaluating and deploying the correct set of reliable and cost-effective solutions to help the Companies achieve its clean energy goals.

Scope: MECO's Action Plan for Lanai for energy storage over the next five years (2014–2018) consists of three (3) primary components:

1. Develop and deploy utility-owned and -operated energy storage project if feasible.
2. Conduct energy storage research and demonstration projects.
3. Assess and track energy storage technologies and applications.

1. Develop and deploy utility-owned and -operated energy storage project projects if cost-effective

MECO intends to work with the community and Lanai Resorts on possible energy storage on Lanai that are line with community needs. The opportunities to integrate cost effective storage projects will be dependent on the future challenges that the island may see with increased intermittent generation, time of day load shifting, microgrids, and either increasing or decreasing energy usage of MECO's generation. There is significant uncertainty in Lanai Resorts' plans that impact the need for and benefits of energy storage on the island. In fact, Lanai Resorts is reportedly considering various types of energy storage such as pumped hydro and compressed air[189]. At this time, it is prudent for MECO to continue to engage with the community and with Lanai Resorts rather than planning a specific energy storage project independently.

2. Conduct energy storage research and demonstration projects

Due to technology risks and evolving business cases for energy storage, the Companies have taken a measured approach in evaluating the performance and cost of energy storage technologies. To offset the technical and business risks, the Companies are engaged in collaborative opportunities with outside entities. The Companies' energy storage activities on each island are detailed in the individual island action plans. Here is a summary of MECO's current energy storage activities:

MECO is currently testing potential benefits of two energy storage systems on Maui as part of the on-going Maui smart grid demonstration projects:

- MECO is commissioning a 1 MW/1 MWh lithium ion BESS at its Wailea substation on the island of Maui as part of the DOE-funded, HNEI-led Maui Smart Grid project. The BESS will provide peak circuit load reduction and voltage support. Installation was completed in June 2013. Operation of this BESS is expected to continue through 2018.
- MECO is also installing and testing an 18kW/33kWh BESS at its Kahului baseyard.

Small-scale energy storage systems such as these could be used to provide a demand response function through manual operation or frequency response, provide local voltage/VAR control and/or if aggregated, provide regulating reserve.

MECO is pursuing a BESS project on the island of Molokai in collaboration with HNEI to provide frequency regulation and PV integration support. Terms of the collaboration and preliminary technical assessments continue to be developed. Although a project schedule has not yet been developed, installation of the BESS is anticipated to occur in 2014.

MECO, in collaboration with Japan's New Energy and Industrial Technology Development Organization (NEDO) and Hitachi, will be planning on using

[189] "Calif. Energy official 'chief architect' for Lanai project", by Lee Imada, Maui News, May 18, 2013

both lead–acid and lithium Ion batteries to simulate EV charging on circuits. While not specifically designed to do so, this type of changing can provide insights to load shifting actions performed by a battery.

As described in the energy storage action plans for Hawaiian Electric, HELCO, MECO, the Companies are following a broad-based application strategy to evaluate the merits of energy storage. The applications of the Companies' energy storage research and demonstration projects were purposely varied to enable investigation of various operational issues. For example, BESS projects were sited and developed to address different operational categories such as system-level response to voltage and frequency events, substation-based assets to manage load and impacts of aggregated PV, integrated assets to manage individual IPP PV projects, and mitigation of impacts from customer-sited generation and loads.

The existing BESS demonstration projects are envisioned to continue within the 2014–2018 Action Plan time frame, and in some cases, beyond this period to provide the Companies with operational experience. This experience will be valuable to the Companies in future energy storage planning and operational functions.

3. Assess and track energy storage technologies and applications

The Companies continue to assess and track energy storage technologies and demonstration projects through technical evaluations, site visits, direct communications and technical briefings with vendors, electric utility interactions, and its Electric Power Research Institute (EPRI) membership. To date, the Companies have met with over thirty (30) energy storage manufacturers, inverter manufacturers, and system integrators. The Companies also increase its knowledge base through interactions with independent power producers (IPPs) and associated project partners that sell renewable energy to the Companies from generation projects that utilize battery energy storage systems (BESS) to meet performance requirements under power purchase agreements (PPAs). Utility scale BESS projects have been installed at two wind farms on Maui, one PV project on Lanai, and one wind farm on Oahu (not currently operational due to a fire in August 2012). The Companies continue to monitor the BESS procurement and operating activities by Kauai Island Utility Cooperative (KIUC) to manage the impacts of large PV installations in its service territory.

The Companies will continue to assess energy storage technologies throughout the five-year Action Plan period to keep abreast of commercial and emerging technologies, application by electric utilities, and advancements in the energy storage industry.

Fairness — Lanai

5. Address Issues with Existing Distributed Generation Programs

5.A. Standardize Interconnection

Purpose: To standardize interconnection process and practices at HECO, HELCO, and MECO, and to implement in a fair and efficient manner for customers.

Scope: The Companies will collaborate to ensure consistent utilization of Rule 14H and adopt best practices to streamline processes. The Companies will support future Commission reviews of its interconnection tariffs to further improve on their fairness, such as reviewing whether the current "first-come, first-served" interconnection approach best serves the interests of all interconnected customers.

To mitigate the cost impact of such studies and upgrades on an individual small customer, the Hawaiian Electric Companies will uniformly adopt the practice of proactively studying and upgrading electric circuits to accommodate multiple PV customers, and will pro-rate the associated study and upgrade costs to customers as they request to install their PV systems. In this manner, costs will be spread across more customers and PV systems will be more efficiently interconnected.

5.B. Implement Technical Solutions for DG

Purpose: To study, develop, and implement technical solutions for high penetration of distributed generation.

Scope: The Companies will collaborate on and standardize technical solutions to mitigate safety and reliability issues associated with high penetration of distributed generation. Where required, proactive cluster studies and system impact studies will be conducted. The Companies will evaluate, demonstrate, and deploy new technologies including those associated with smart grid to upgrade infrastructure to support future interconnecting customers.

5.C. Review Policies

Purpose: Review policies, programs, and rules for best interests of all customers.

Scope: In order to facilitate a fair and continued safe deployment of distributed generation systems, the Companies will review internal policies, Tarff Rules, and programs. Hawaiian Electric will participate in and support Commission reviews of its interconnection tariffs and energy procurement programs to improve their fairness and effectiveness in acquiring cost-effective clean energy for the benefit of all customers. The Companies will fully participate in Commission-ordered regulatory dockets to review these issues, as was recommended by the RSWG Independent Facilitator.

V. APPENDICES