Hawaiian Electric Power Supply Improvement Plan

August 2014

Hawaiian Electric
Maui Electric
Hawai‘i Electric Light

Hawaiian Electric Company submits this Power Supply Improvement Plan to comply with the Decision and Order issued by the Hawai'i Public Utilities Commission on April 28, 2014 in Docket No. 2011-0206, Order No. 32053. The Companies retained Black & Veatch, Boston Consulting Group, Electric Power Systems, HD Baker and Company, PA Consulting Group, and Solari Communication to assist in the creation of this plan.

The Hawaiian Electric Companies created this PSIP based, in parts, on a realization of the current state of the electric systems in Hawai'i, forecast conditions, and reasonable assumptions regarding technology readiness, availability, performance, applicability, and costs. As a result, this plan presents a reasonable and viable path into the future for the evolution of our power systems. We have attempted to document and be fully transparent about the assumptions and methodologies utilized to develop this plan. We recognize, however, that over time these forecasts and assumptions may or may not prove to be accurate or representative, and that the plan would need to be updated to reflect changes. As we move forward, we will continually evaluate the impacts of any changes to our material assumptions, seek to improve the planning methodologies, and evaluate and revise the plan to best meet the needs of our customers.

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Executive Summary

This Power Supply Improvement Plan (PSIP) defines Hawaiian Electric's vision for transforming the electric system to meet customer needs, implement the State of Hawai'i's policy goals, and secure a clean and affordable energy future. Based on the Company's ongoing strategic planning efforts, the PSIP includes a realistic, flexible and operable tactical plan (the "Preferred Plan") that recognizes our collective goals and the realities of our situation. For O'ahu, the PSIP increases renewable content of electricity to approximately 61% by 2030, and reduces full service residential customer bills, on average, by 22% in real terms. For the Hawaiian Electric Companies the consolidated renewable content of electricity increases to approximately 67% by 2030.

We take our obligations to our customers seriously. This report represents enormous amounts of thoughtful and thorough analysis to provide the most credible plan possible for our customers.

OUR SHARED VISION

Our vision is to deliver cost-effective, clean, reliable, and innovative energy services to our customers, creating meaningful benefits for Hawai'i's economy and environment, and making Hawai'i a leader in the nation's energy transformation. Hawai'i has the potential to become a national model for clean energy by not only achieving the highest Renewable Portfolio Standard (RPS) goal in the nation by 2030, but also by leading the way to define the utility model of the future.

To achieve this, we believe the Hawaiian Electric Companies have a responsibility and a unique opportunity to evolve in Hawai'i's complex and rapidly changing energy ecosystem. In this dynamic environment, no single party can realize this future for

Hawai‘i. For this reason, we seek a shared vision with our customers, regulators, policy makers and other stakeholders in order to achieve shared success for all of Hawai‘i.

THE PSIP ACHIEVES UNPRECEDENTED LEVELS OF RENEWABLE ENERGY

The Hawaiian Electric Companies will not just meet the mandated RPS of 40%, but will achieve an unprecedented level of 67% by 2030. As illustrated in Figure ES-1 and Figure ES-2, for O‘ahu alone, the Hawaiian Electric Preferred Plan more than triples the projected RPS from 2015 to 2030, from 18% to 61%. A significant amount of market-based, distributed solar photovoltaics (PV) is included in the Preferred Plan and accounts for about one-third of this total.

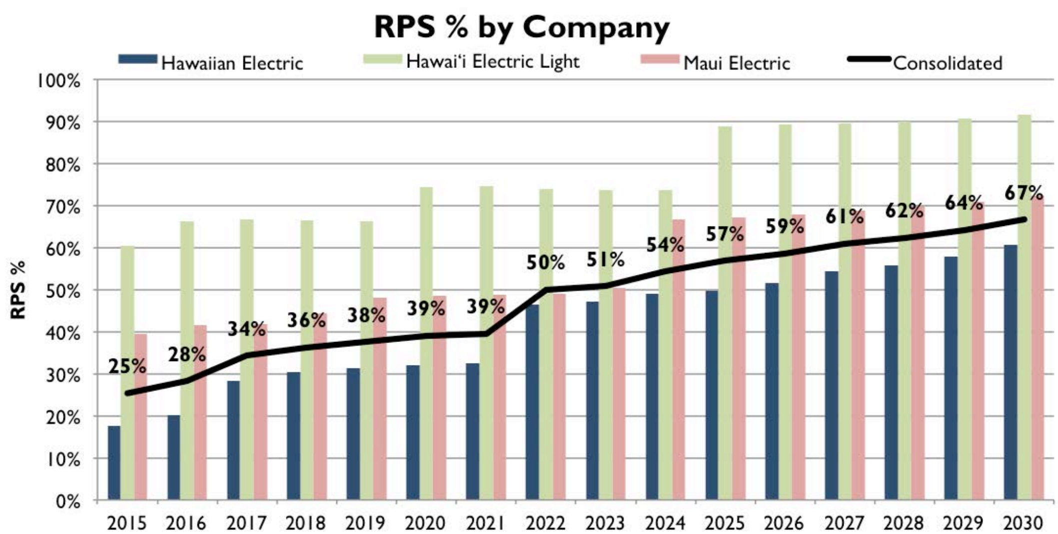

Figure ES-1. Renewable Portfolio Standard (RPS) for the Hawaiian Electric, Maui Electric, Hawai‘i Electric Light, and the Consolidated Companies, 2015–2030.

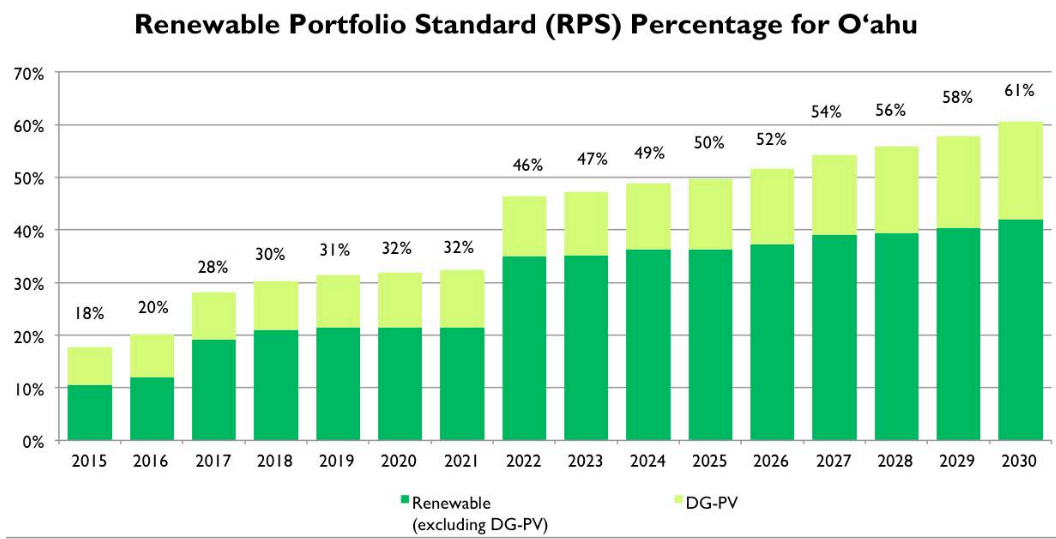

Figure ES-2. Renewable Portfolio Standard (RPS) for Hawaiian Electric on O'ahu, 2015-2030, showing the relative contribution from distributed generation (DG-PV)

Maximizes Utilization of Renewable Energy

From 2015 through 2030, 97.3% to 100% of the estimated energy produced from all variable renewable resources on O'ahu would be utilized (not curtailed) each year (Figure ES-3). This is accomplished by:

- Installing energy storage to provide regulating and contingency reserves.
- Using demand response as a tool for better managing system dispatch.
- Selecting future thermal generation resources that have a high degree of operational flexibility.
- Increasing the operational flexibility of existing thermal generation not slated for retirement during the planning period.
- Reducing the "must-run" requirements of thermal generators.

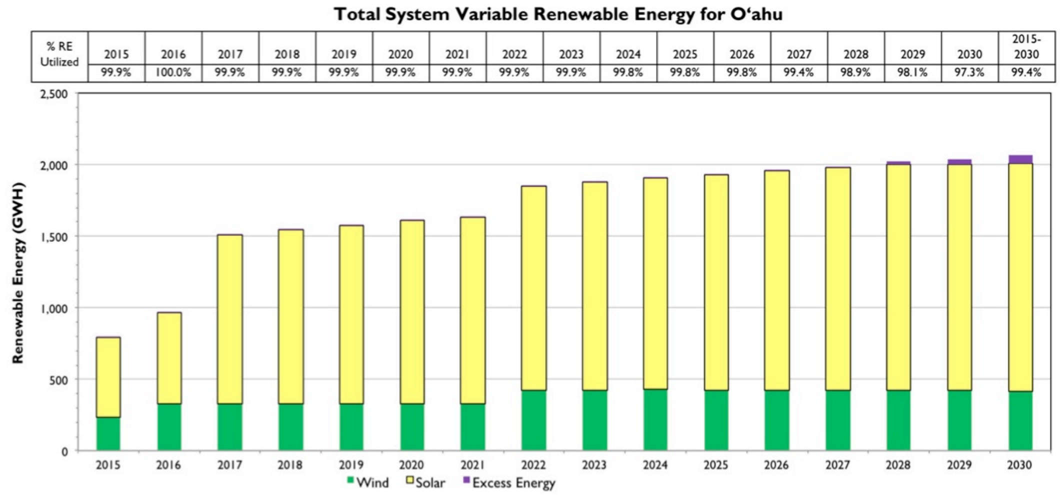

Figure ES-3. Total System Variable Renewable Energy Utilized by Hawaiian Electric

It should also be noted that the utilization is >99% for every year except the last three in the planing period (that is, 2028 to 2030), and it is still >97% even in this period. This results from the exponential growth of energy efficiency that is forecast to occur in the planning period. Conversely, if there is slight load growth during the intervening years (for example, due to higher adoption rates of electric vehicles), then utilization of energy produced from variable renewable energy resources would remain close to 100%.

The Preferred Plan Provides a Hedge Against Fuel Price Volatility

In developing the Preferred Plan, conscious choices were made to blend resources that move the generation mix away from fossil-fuel resources. This was done, in part, to provide a financial hedge against fuel price volatility and future uncertainty with respect to fuel availability.

When the analysis result showed a "close call" between a renewable and non-renewable option, the renewable option was chosen. The effects of fuel price volatility were a determining factor for some resource selections. Accordingly, renewable resources that consume no fuel were selected for the PSIP in some cases where they were not the obvious low-cost option. The selections of new generation resources for inclusion in the Preferred Plan were based on economics, planning flexibility, and operational flexibility.

Full consideration was also given to the portfolio value that demand response[1] and energy storage technologies, both non-fuel consuming options, can provide; both were found to make valuable contributions.

[1] As defined in the *Integrated Demand Response Portfolio Plan* (IDRPP), filed by the Companies on July 28, 2014.

OVERVIEW OF THE PREFERRED PLAN

Energy Mix

Figure ES-4 illustrates the energy mix for O‘ahu from 2015 to 2030. Renewable energy from distributed PV continues to grow over time; new utility-scale PV and wind are added to the system. As firm generating units are deactivated and decommissioned, new flexible firm generation is added in its place. Oil is replaced by liquefied natural gas (LNG), and a portion of the coal is replaced by biomass.

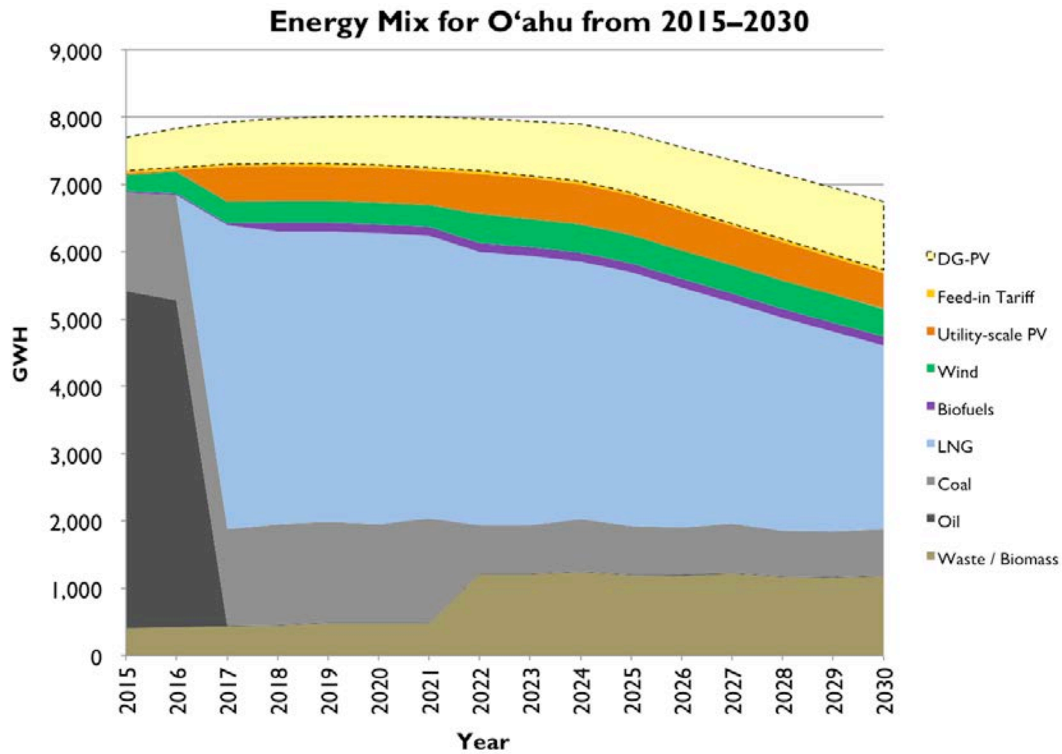

Figure ES-4. Annual Energy Mix of Hawaiian Electric Preferred Plan

The Hawaiian Electric Preferred Plan for 2015–2030 can be summarized as follows:

- Increases customer-owned distributed generation three-fold.
- Adds large amounts of new utility-scale solar.
- Adds modest amounts of new utility-scale wind.
- Aggressively expands our demand response programs.
- Installs energy storage for regulating and contingency reserves.
- Switches to low-sulfur fuels to meet environmental regulations.
- Procures LNG coupled with modifying certain generating units to burn LNG.

- Installs new LNG-fired combustion-turbine and combined cycle capacity to replace retired thermal units, which provides the generation flexibility necessary to accommodate high penetrations of distributed and utility-scale renewables.
- Deactivates all existing oil-fired generators.
- Installs internal combustion engine generators at Schofield Barracks, fueled with biofuels and LNG.
- Converts AES Hawai‘i from 100% coal to 50% biomass and 50% coal.
- Modernizes our power grid with smart technologies.

Timeline for the Preferred Plan

Figure ES-5 illustrates the timeline for the Preferred Plan for the Hawaiian Electric power system on O‘ahu for 2015–2030. It shows when new resources would be added (above the date line) and existing resources would be retired (below the date line).

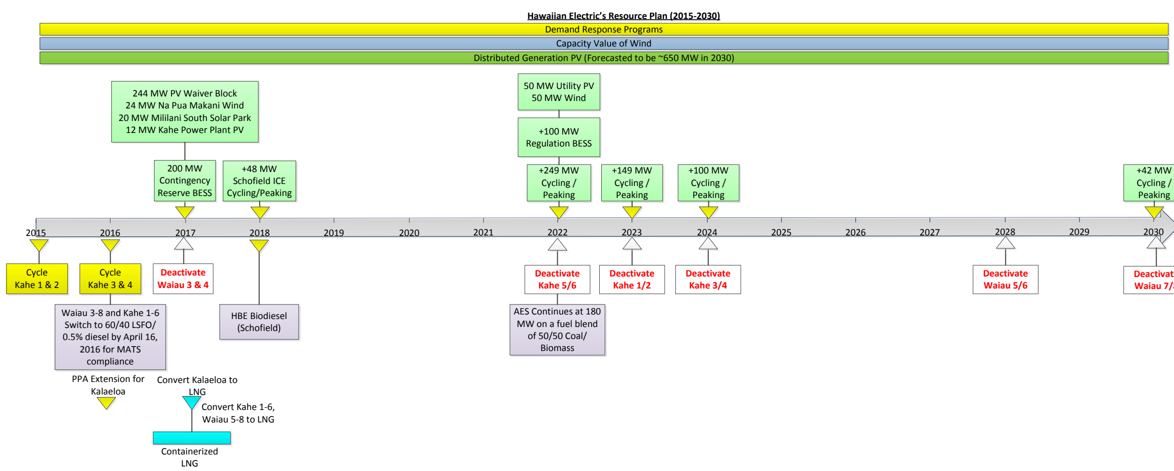

Figure ES-5. Hawaiian Electric Preferred Plan 2015–2030

The Preferred Plan is Realistic

The Preferred Plan accomplishes our strategic vision of the 2030 power system in a way that is both realistic and achievable.

The Preferred Plan relies only on technologies that are commercially ready today and that can be successfully developed in Hawai‘i's unique political and social environment.

Recognizing that the investment to implement the Preferred Plan will be substantial, and perhaps beyond the ability of a single entity to make, the plan assumes a mix of utility and third-party investment in new infrastructure. The Preferred Plan does not rely on a single large capital project to achieve success and thus, portfolio risk is well diversified.

Finally, the Preferred Plan is "operable". In other words, the plan is based on sound physics, engineering, and utility operating principles.

The Preferred Plan Reduces Customer Bills

The Preferred Plan identifies those transformational and foundational investments needed to reliably serve customers across O'ahu with flexible, smart, and renewable energy resources.

The Preferred Plan, coupled with changes in rate design that more fairly allocates fixed grid costs across all customers (assumed effective in 2017), is expected to reduce monthly bills for average full service residential customers by 22% from 2014 to 2030 (Figure ES-6).

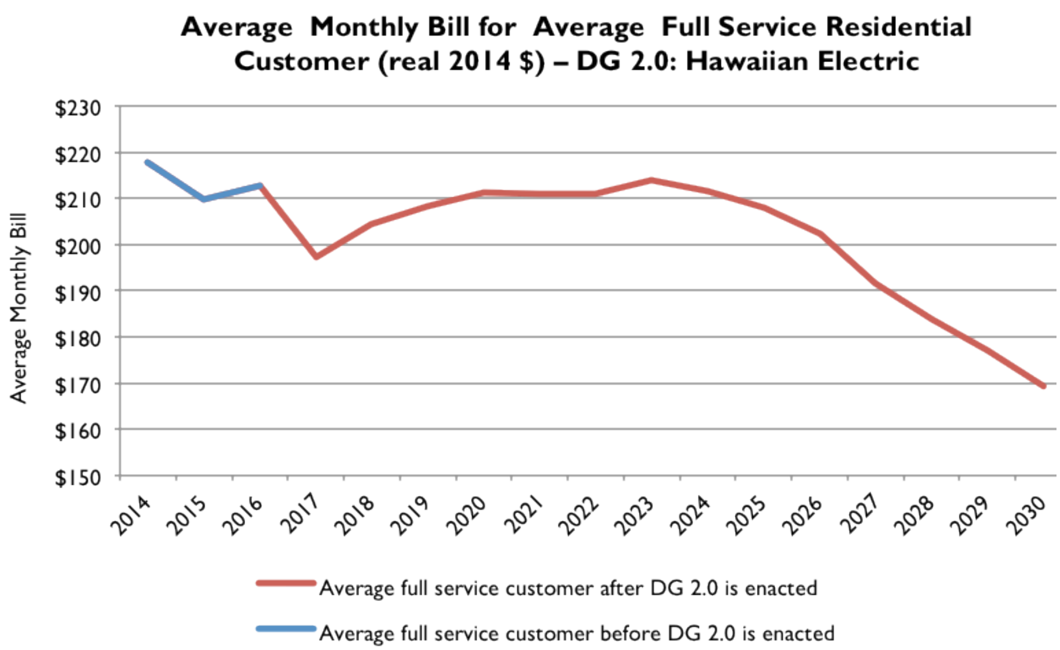

Figure ES-6. Average Full Service Residential Customer Bill Impact

The customer bill reductions are driven by projected changes in the underlying cost structures.

Fuel expense declines significantly over the planning period, driven by the continued shift toward renewable generation and the cost savings, beginning in 2017 with the introduction of LNG.

Purchased power costs increase over the planning period, reflecting both the expanding purchases of renewable energy and the capacity costs for replacement dispatchable generation.

Operations and maintenance (O&M) expenses are expected to decline in real terms across the planning period, driven by the reduced costs associated with Smart Grid and information technology investments.

The Preferred Plan is Flexible

The Preferred Plan is flexible and can be adjusted based on changing conditions as we move toward 2030.

Planning Flexibility: The ability to make adjustments regarding capital intensive resource decisions was accomplished through a combination of retiring less efficient power plants, and selecting new resources from a menu of generation, demand response programs, and energy storage options that can be developed in relatively short time frames.

Operational Flexibility: The selected thermal generation resources exhibit a high degree of operational flexibility across a wide range of duty-cycles and system conditions.

Technological Flexibility: The Preferred Plan can be immediately implemented using proven technologies that are available today. The Preferred Plan, however, is also flexible enough to retain the ability to change the mix of future resources in response to system conditions that differ from those assumed today. The plan also allows for the incorporation of emerging technologies that may achieve commercial readiness or produce cost savings in the future.

Financial Flexibility: The plan is agnostic with respect to ownership of incremental resource additions.

TRANSPARENCY

The planning approach we have taken provides our customers and other stakeholders with a transparent view of the options considered and the potential tradeoffs assessed as part of the planning analyses. To this end, we assembled numerous assumptions and forecasts critical to the analyses, and utilized sophisticated and comprehensive production simulation models to analyze alternatives. These models employed a variety of modeling techniques, and all were based on utility planning and operating methods with worldwide utility-industry acceptance.

Achieving the aggressive goals in this plan requires that all stakeholders be aligned in moving forward expeditiously. As with any planning process of this magnitude, the forecasts and assumptions incorporated in this PSIP may or may not be borne out.

However, we made what we believed were logical, fair, and assumptions that support near term actions.

EXECUTION OF THE PREFERRED PLAN

The Preferred Plan clearly identifies the strategic initiatives that must be implemented in order to continue the journey toward a more sustainable energy future.

The Preferred Plan is clear with respect to near-term actions that must be initiated on the path toward a realization of our shared vision. We are committed to do our part. We will continue to transform and collaborate to make this a reality. The Commission has already opened a docket to review our PSIPs. We look forward to the additional insight and any required approvals to keep moving toward our shared goals.

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1. Introduction

We operate in an environment that is defined by geography, changing technology, and policies intended to promote clean energy. These conditions create opportunities, as well as challenges, as we move into the future. We intend to adapt to changes in market and technological conditions to meet the challenges along the way. Accordingly, we have initiated a comprehensive strategic planning effort to position the Hawaiian Electric Companies to provide high value energy services to our customers, and promote the economic well-being of Hawai‘i. Our plan is based on extensive analysis of the current situation and of future opportunities. We have integrated our findings into a Preferred Plan that increases renewable content of electricity in Hawai‘i to 67% by 2030 and reduces full service customer bills by 22% to 30%.

THE POWER SUPPLY IMPROVEMENT PLAN

The Hawaiian Electric Companies were ordered to create Power Supply Improvement Plans (PSIPs) for each operating utility. The resultant PSIPs are tactical, executable plans based on well-reasoned strategies that can be implemented expeditiously. They are supported by comprehensive analyses in resource planning, and focus on customer needs.

Goals of the PSIP

Utilizing a strategic "clean slate" view of 2030, we created a balanced portfolio of the optimal mix of generation, both thermal and renewable, demand response, and energy storage to:

- Successfully and economically integrate substantial amounts of renewable energy.
- Maximize the utilization of renewable energy that is produced.
- Maintain system reliability.
- Systematically retire older, less-efficient fossil generation.
- Reduce "must-run" generation.
- Increase generation operational flexibility.
- Utilize new technologies for grid services.

The result of our effort is a tactical *Preferred Plan* for each operating utility—that can be confidently and expeditiously implemented.

OVERVIEW OF THE PSIP

This document is organized as follows:

Chapter 1. Introduction: An introduction to and an overview of the contents of the PSIP.

Chapter 2. Strategic Direction: A high-level vision of our power grid in 2030.

Chapter 3. Generation Resources: The current state of our power grids.

Chapter 4. Major Planning Assumptions: A discussion of the major assumptions upon which we based our modeling analyses to develop the Preferred Plans.

Chapter 5. Preferred Plan: A presentation of our Preferred Plan to attain the goals of the PSIP.

Chapter 6. Financial Implications: An analysis of the financial impacts of implementing the Preferred Plan.

Chapter 7. Conclusions & Recommendations: A summary of the conclusions derived from our analyses and recommendations moving forward

Appendices A–N: A series of appendices that provide supporting information and more detailed discussions regarding the creation of the PSIP.

HAWAIIAN ELECTRIC SYSTEM LOAD PROFILES

System loads throughout the day on our electric power grids have changed dramatically over the past eight years. As an example of this change, Figure 1-7 shows this trend on the O'ahu grid using data from the first week of June during the period from 2006 to 2014. This is not only an accurate representation for every week of a year on O'ahu, but is also relevant for the Maui Electric and Hawai'i Electric Light power systems.

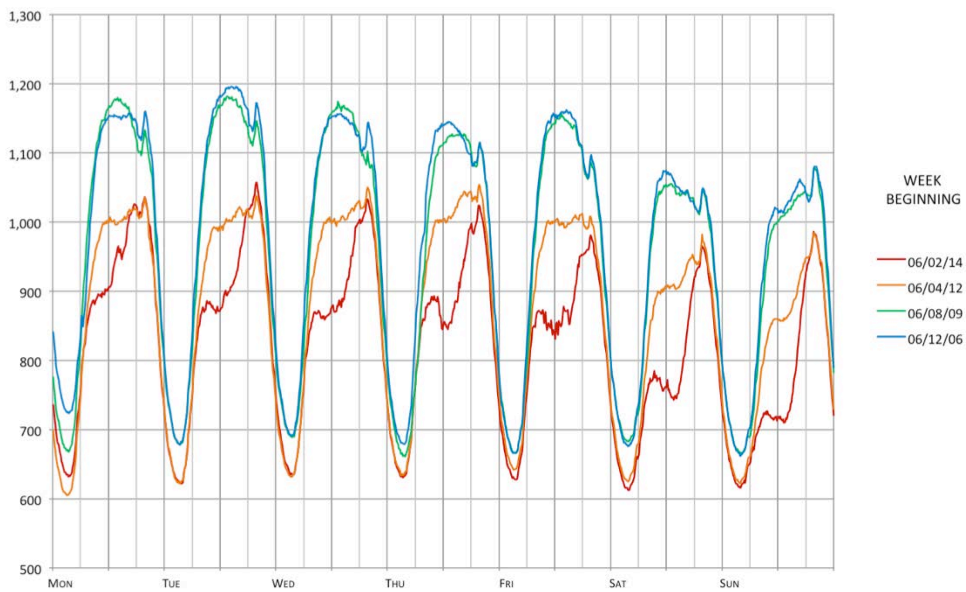

Figure 1-7. O'ahu System Load Profiles, 2006–2014

A review of load profiles from recent years yields the following observations:

- Daytime peak loads on the O'ahu grid in 2006 and 2009 regularly reached 1,200 MW; in 2014, daytime peak loads only reach approximately 850 MW: a drop of about 30%.
- Over the past four years, the summertime system load has shifted from a daytime peak to an early nighttime peak, due mainly to distributed solar generation.
- System minimum loads have also lowered, due mostly to energy efficiency measures.

This trend suggests that sales and peaks have declined which, coupled with the growth in distributed generation photovoltaics (DG-PV), is a harbinger for greater challenges operating a stable and reliable grid.

RENEWABLE ENERGY INTEGRATION AND DIVERSITY

The generation portfolio of the future will be comprised of greater amounts of variable renewable resources, complemented by firm thermal generation that will be both renewable and fossil fueled. The renewable energy will be derived from solar (both distributed generation and utility-scale generation), wind, hydroelectric, biomass (including waste), and geothermal resources. Energy storage and demand response will play integral roles in the grid of the future, while the role of fossil fuels will continue to diminish.

A Portfolio of Diverse Renewable Generation

The state of Hawai‘i is blessed with abundant sunshine, generous winds, and geothermal resources that can be harnessed for energy production, but no indigenous fossil fuels. Recognizing this, we have the most aggressive Renewable Portfolio Standard (RPS) in the nation. The Hawaiian Electric Companies are already on course to exceed the mandated RPS of 40% in 2030. Our PSIP further exploits Hawai‘i’s natural resources, creating plans to significantly exceed the RPS requirements.

The Role of Thermal Generation

Even with an abundance of renewable energy resources, the power system must have a complement of firm, dispatchable thermal resources. Historically, these types of generators provided bulk power for transmission and distribution throughout the electric grid. In the future, they will be called upon to generate power during periods when variable renewable generation is unavailable (that is, periods of darkness, extended storms, or no wind), and to provide valuable grid services to sustain grid reliability. These thermal resources will be fueled by liquefied natural gas (LNG), which is lower cost and environmentally cleaner than petroleum-based fuels.

Energy Storage

Continued advancements in energy storage technology harbors increased opportunities for employing additional amounts of variable renewable resources onto the electricity grid at reasonable costs. Our PSIP analyzes and develops a plan for using energy storage systems (ESS) to maximize renewable energy utilization (minimize curtailment) and sustain frequency regulation and dynamic stability requirements.

Demand Response (DR)

Demand response can enable grid operations, save costs, and provide customers more options to manage their bills and be active contributors to the electric system. Power systems have historically controlled the supply of power to match the uncontrolled demand for power. Demand response programs empower customers and system operators to work collaboratively to balance load supply and demand through innovative technology and programs. Toward that end, we have designed and will implement DR programs[2] across the entire state, and have incorporated the utilization of DR in our Preferred Plans.

FINANCIAL IMPLICATIONS

The transformation of the power system will require significant investments by the company and third parties to build the necessary flexible, smart, and renewable energy infrastructure needed to reliably serve customers across the state. We have developed estimates of foundational and transformational investments that will need to be made during the planning period. And, through detailed hourly and sub-hourly production simulation modeling, have estimated the fuel, power purchase, operating, and maintenance expenses resulting from implementation of the Preferred Plans. A financial model was utilized to examine the financial implications of the PSIPs for customers.

OVERVIEW OF OUR PREFERRED PLAN

For each operating utility, we have developed a Preferred Plan for transforming the system's current state to a future vision of the utility in 2030 consistent with the Strategic Direction we set forth to achieve long-term benefits for our customers and our state (and is presented in Chapter 2).

Implementation of these Preferred Plans will transform the electric systems on O‘ahu, Maui, Lana‘i, Moloka‘i, and Hawai‘i, and will substantially decrease our reliance on imported fossil fuels and reduce customer bills while integrating tremendously high levels of renewable energy. More than 65% of our energy will be provided by renewable energy resources in 2030, significantly surpassing our state's renewable energy target and securing Hawai‘i's place as a national leader in clean energy.

[2] The Companies filed its *Integrated Demand Response Portfolio Plan* (IDRPP) with the Commission on July 28, 2014.

Our Shared Vision

Our vision is to deliver cost-effective, clean, reliable, and innovative energy services to our customers, creating meaningful benefits for Hawai‘i’s economy and environment, and making Hawai‘i a leader in the nation’s energy transformation. Hawai‘i has the potential to become a national model for clean energy by not only achieving the highest Renewable Portfolio Standard (RPS) goal in the nation in 2030, but also by leading the way to define the utility model of the future.

To achieve this, we believe the Hawaiian Electric Companies have a responsibility and a unique opportunity to evolve in Hawai‘i’s complex and rapidly changing energy ecosystem. In this dynamic environment, no single party can realize this future for Hawai‘i. For this reason, we seek a shared vision with our customers, regulators, policy makers, and other stakeholders in order to achieve shared success for all of Hawai‘i.

2. Strategic Direction

A healthy, resilient, and cost effective power supply and electric power delivery system is vital to the well being of the people of Hawaiʻi. The Hawaiian Electric Companies provide service to over 450,000 customers across five of the Hawaiian Islands, and because our customers expect and depend on reliable electric service, we are in contact with them every second of every day. We believe that a healthy, viable, and progressive utility is imperative for managing, producing, and delivering the electric energy that is essential to our economy.

We operate in an environment that is defined by geography, changing technology, and policies intended to promote clean energy. These conditions create opportunities, as well as challenges, as we move into the future. We intend to adapt to changes in market and technology conditions and to meet the challenges along the way. Accordingly, we have initiated a comprehensive strategic planning effort to position the Hawaiian Electric Companies to provide high value energy services to our customers, and promote the economic well being of Hawaiʻi.

While our strategic planning is an ongoing effort, the work that has been accomplished to date has defined Power Supply Improvement Plans (PSIPs) that cover the desired end states, and the path to progress from the current state to the desired end state by 2030.

SHARED VISION

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COMMON OBJECTIVES

Common objectives across stakeholders drive the energy landscape of the future.

We share the Hawaiʻi Public Utilities Commission's commitment to lower, more stable electric bills; increased customer options; and reliable electric service in a rapidly changing environment.[3] In order to drive the transformation for Hawaiʻi, we have anchored our strategies in a set of common objectives.

These common objectives include:

1. **Affordable costs, reflecting the value provided to, and by, customers.** We will create sustainable value for our customers by providing affordable, stable and transparent costs. We will fairly compensate customers for the benefits they provide to the grid, while also fairly pricing the benefits customers derive from the grid.
2. **A clean energy future that protects our environment and reduces our reliance on imported fossil fuels.** Hawaiʻi is uniquely positioned to embrace the development of local renewable energy resources and increase our energy security. We will achieve a renewable portfolio that significantly exceeds the minimum standard of 40% by 2030.
3. **Expanded and diversified customer energy options.** We will serve all connected to the grid, including those with and without distributed generation (DG), through customized levels of grid services, electric power delivery and value-added products and service offerings.
4. **A safe, reliable and resilient electric system.** We will provide a level of reliability that supports our customers' quality of life. We are unwavering in our commitment to safety and reliability; these principles are the bedrock of any electrical system. Recognizing Hawaiʻi's remoteness and lack of interconnections, we must have an

[3] See "Commission's Inclinations on the Future of Hawaiʻi's Electric Utilities", Exhibit A attached to Decision and Order No 32052, filed on April 28, 2014, in Docket No. 2012-0036, at 3.

electric system resilient enough to support the continuous flow of energy to our communities through a wide variety of conditions and circumstances.

5. **A healthy Hawai'i economy.** We will contribute to the health and diversity of Hawai'i's economy for the benefit of all stakeholders.

6. **Innovation in energy technologies.** We will actively pursue new clean energy technologies in partnership with others to bring energy solutions to our customers.

APPROACH FOR THE PHYSICAL DESIGN OF THE ELECTRIC SYSTEM IN 2030

A transformation of the physical components of the grid (for example, generators, transmission and distribution infrastructure, non-transmission alternatives) is vital for the Companies to deliver on this vision. It requires both a clear understanding of the goals as well the ability to identify and implement a path from the current state to the desired end state.

The Companies recognize that the environment in which they operate is constantly changing. Continuous monitoring of market trends and changing circumstances are **critical for fact-based planning.** This **will require adjustment** of our **strategic and tactical plans within the planning horizon.**

To cope with the changing market trends, to support this transformation, to set goals and to set the path forward, the Companies have developed the Power Supply Improvement Plans in two steps:

A. **Step A: Define the desired end state for the physical design of the power system in 2030**

   This step was accomplished by developing a series of "clean sheet" hypothetical end states for 2030 that allowed the Companies to understand the broad ramifications associated with different futures, and choosing an end state that is in our view the best balance of objectives over the long term. The end state chosen is consistent with the underlying principles, recognizes the uniqueness of island grids, and promotes the State's clean energy policies.

B. **Step B: Define and validate a path to transform from the current state to the desired end state in 2030**

   This step was accomplished through application of utility industry accepted planning methods that take into account existing system conditions, technology commercial readiness, reliability and cost considerations. Chapters 3 through 7 and the appendices of this report provide the details of how this analysis was accomplished and the results of that analysis.

This approach enables our customers and other stakeholders to have a transparent view of the options considered and the potential tradeoffs[4] assessed during these analyses.

Step A: Clean-sheet analysis to define a desired end state and provide strategic direction

The goal of 'Step A'[5] was to provide high-level guidance for the physical design of the electric system in 2030, the end of the planning horizon considered in this PSIP. In order to ensure an un-biased and clean-sheet approach in defining the future physical design, the following guidelines were used in this step of the analysis:

- Forward-looking optimization focusing on 2030 as the single year.
- Using a fact-based and industry accepted set of assumptions and forecasts.
- Avoiding any pre-conceptions and not favoring any particular technology.
- Taking an ownership-agnostic view.
- Applying a spectrum of end state options to assess trade-offs.
- Applying a clean-sheet approach to define service reliability requirements.
- Evaluating the cost of the physical design options from an "all-in" societal perspective to consider the impact to Hawai'i versus any particular customer class (in this definition all-in societal costs included the total costs of DG-PV installation and maintenance in addition to all the utility-scale generation costs and T&D costs).[6]
- Using common objectives stated above to select the desired end state in 2030.

The goals of the approach were to assess the impact of various end states and to select one that the Companies should pursue as the desired target for the physical design in 2030.

Step B: Detailed and tactical production analytics to define and validate the path

In Step B., the focus shifted from goal setting to developing a detailed tactical and executable plan from today to the final vision in 2030, considering the feasibility, costs, risks, and activities required to support the transition. The operability of the system

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4 For instance one tradeoff might be low cost and another low cost volatility. Choosing the absolute lowest cost might result in high cost volatility. In a case like this we chose a path that resulted in a balance between low cost and low cost volatility.

5 The strategic exercise under Step A has been performed on O'ahu, Maui and Hawai'i Island; Lana'i and Moloka'i were assessed separately within the detailed and tactical production analytics.

6 Note that the evaluation under Step A was performed only for the clean-sheet analysis. The Preferred Plan and Financial analyses presented later in this report do not include customer-incurred costs related to installation and maintenance of customer-installed generation.

under various physical designs, as well as both normal and likely off-normal[7] circumstances, was tested and validated within an integrated planning and production simulation environment. Given the importance and complexity of this analysis, the Companies elected to create a unique, collaborative, and iterative modeling process powered by different models and participants. This process proved to be invaluable both in terms of validating key tactical and transitional solutions as well as providing a forum to test and refine concepts.

The detailed production simulations define the following annually from 2015 to 2030: existing generation portfolio, timing and characteristics of individual projects, retirements, implications of new tariffs (for example, DG 2.0)[8] and customer offerings (for example, Demand Response), system reliability, and operational requirements. This provides the ability to assemble and optimize the power system portfolio and grid design across time, consistent with our overall objectives to be cost-effective, to exceed the Renewable Portfolio Standard (RPS) goal, to reduce dependency on high-priced fossil fuels, to diversify and "green" the energy portfolio, and to establish a basis for implementing advanced technologies such as energy storage. **The analytical product is the Preferred Plan that is presented in Chapter 5 of this report.**

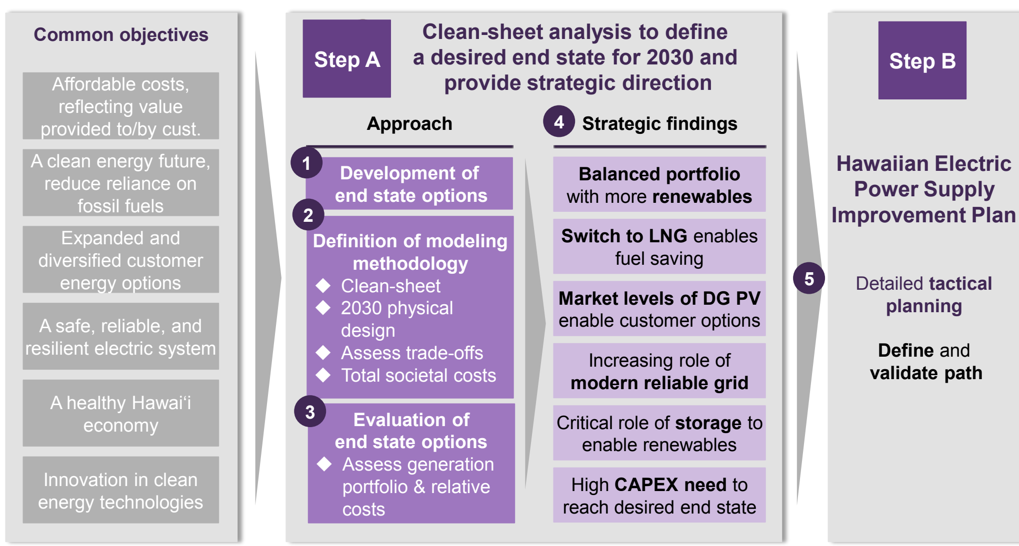

Figure 2-1. Approach to Define Desired Physical System Design 2030 End-State

The remainder of this chapter will focus on describing Step A in more detail.

[7] Off-normal circumstances include likely events like trip of a large generating unit, trip of a heavily loaded transmission line, etc.

[8] A generic term used to describe revised tariff structures governing export and non-export models, based on fair allocation of costs among distributed generation (DG) customers and traditional retail customers, and fair compensation of DG customers for energy provided to the grid.

Step A: Clean-Sheet Evaluation and Selection of the Desired End State

Development of End State Options

Five high-level physical design end state options were developed for the evaluation, reflecting a set of alternative futures with key trade-offs and differentiating factors, and fulfilling the necessary condition of achieving RPS targets and maintaining an operable system at affordable costs[9]. Five end state options were defined.

'Benchmark' end state: Describes the Companies' current liquid fuel-based portfolio trajectory with increasing DG-PV integration under the existing regulatory tariff and new utility-scale renewable projects that have already been submitted for approval to the PUC. It assumes LNG is not an accessible option for the islands.

'Least cost' end state: Describes the physical design assuming only the existing level of DG-PV integration, a cost-optimization of utility-scale renewable technologies firmed by LNG. This end state option optimizes the generation mix that results in the lowest overall societal cost level. As the levelized cost of DG-PV is expected to be higher than most other generation sources, DG-PV would not grow from today under the *'Least cost'* end state option.

'Balanced portfolio–DG 2.0' end state: Describes a generation portfolio that is a balance of system costs with increased renewables assuming a market driven DG-PV integration under a hypothetical "DG 2.0" rate structure (described in Chapter 6.), combined with an optimized utility-scale renewables portfolio firmed by LNG.

'Balanced portfolio–DG heavy' end state: Like *'Balanced portfolio–DG 2.0'*, this option seeks a balance of costs and renewables but allows for a much higher DG-PV integration compared with *'Balanced portfolio–DG 2.0'*. It assumes market driven DG-PV integration under the existing regulatory tariff, combined with an optimized, utility-scale renewable-portfolio firmed by LNG.

'100% Renewable' end state: Describes a generation portfolio to achieve 100% renewable share by 2030. It assumes market driven DG-PV integration under the existing tariff structure, maximum required utilization of other renewable resources on the islands, and the use of biofuel and biomass to fuel the necessary thermal generating resources for operability.

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[9] " Affordable" includes both cost and cost volatility thereby including considerations such as fuel diversity.

Definition of Modeling Methodology for Step A

To quickly evaluate and have the flexibility to test each end state option at a high-level—the Companies developed a simplified hourly-based production model for 2030[10]. The model was ownership agnostic regarding generation resources and sought to calculate the total 'all-in societal' costs for the physical design (including generation costs and cost of the DG-PV paid by customers and through tax credits) and T&D costs.

High-Level Modeling Logic for Step A

The high level model for Step A is characterized by the following attributes:

- Hourly supply-demand model was built for 2030 for O'ahu, Maui and Hawai'i Island; Lana'i and Moloka'i were not in the scope of the analysis performed under Step A.
- Levelized cost of energy and technology attributes assessed for over 15 technologies (DG-PV, utility-scale PV, onshore-wind, offshore-wind, ocean thermal, ocean wave, run-of-river hydro, geothermal, waste-to-energy, biomass, coal, various LNG technologies, oil-based steam, biofuel, and energy storage).
- DG-PV installed capacities for 2030 were taken as an input into the model, developed by the Companies and used in the *Distributed Generation Interconnection Plan* (DGIP) and PSIP process.
- High level estimates for reliability requirements were linked to capacities for DG-PV, utility-scale PV and wind for day-time and also linked to wind only for night-time. (Detailed tactical planning in Step B calculates with more precision system security requirements that differ by hour based on the generation portfolio output.)
- Demand was covered for every hour of the year starting with DG-PV considering its hourly load shape, followed by the various technologies based on their cost economics and resource constraints.
- Optimization minimizes aggregated costs across renewable generation, conventional generation, storage costs, curtailment and ancillary services.
- Overall installed firm capacities required were 30% above annual system peak-load
- The assessment did not consider most existing configurations, except that all existing contracts were honored until their expiration.
- The model assumed any and all configurations were operable and reliable.
- All the assumptions used in the model were aligned and consistent with subsequent, more detailed modeling efforts described in Chapters 3 through 7.

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[10] This model considered high-level estimates on reliability constraints, did not consider most existing configurations, except that all existing contracts were honored until their expiration and assumed any and all configurations were operable and reliable.

- Estimates on Transmission & Distribution (T&D) costs have also been added to each of the end state options. The T&D costs encompassed transmission, distribution, smart grid and system operations investments. These costs were derived for each resulting end state option by assessing the expected location of generation assets on the system.

Key input parameters that were included in the strategic model to assess tradeoffs:

- **Demand parameters:** All relevant demand information for 2030, such as hourly demand curves for 2030, including the impact of gross demand and energy efficiency measures, hourly demand response adjustment factors, network losses, and DG-PV integration rates.
- **Supply parameters:** All relevant supply information for 2030, such as technology readiness, levelized cost of energy capital and operating costs per technology for 2030 based on National Renewable Energy Laboratories (NREL) forecasts[11] and Energy Information Administration (EIA) adjustment factors[12], fuel price forecasts, resource constraints per technology, hourly capacity factors per renewable technologies, assumed lifetime of assets, grid integration costs, forecast on DG-PV installed capacities.
- **System security requirements:** Annual reserve margin requirement, day-time and night-time regulating and contingency reserves.
- **Other:** Inflation, cost of capital.

Parameters that were not included in the strategic model (Step A) but were included in the detailed tactical PSIP analytics and modeling (Step B):

- **Demand parameters:** All relevant demand information from 2015 to 2030, sub-hourly information.
- **Supply parameters:** All relevant supply information from 2015 to 2030, unit level technology information, maintenance schedules per unit, existing generation fleet, existing contractual capital cost and energy cost conditions, contractual dispatch requirements and contract duration, differentiation of costs depending on the year of building assets, retirements, minimum load requirement per unit, various type of storage technologies, retirement schedules.
- **System security requirements:** Regulating and contingency reserves on hourly basis; full range of system security requirements in line with the Companies written policies, use of demand response programs for ancillary services.
- **Other:** Avoided cost calculation for Hawai‘i Island PPAs.

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[11] National Renewable Energy Laboratories: Cost and performance data for power generation technologies (2012).

[12] Energy Information Administration: Updated capital cost estimates for utility-scale electricity generating plants (2013).

Key inputs of the model were the following:

- The expected levelized cost of various generation technologies assuming the generation mix is built by 2030
- Resource constraints and technological attributes of alternative technologies
- Service reliability requirements like contingency reserve requirement, regulating reserve requirement, and reserve margins
- Estimated T&D costs to enable interconnection and ensure safe and reliable service

The results of the assessment for Step A were optimized physical design portfolios by each end state option and island considering the costs and attributes of the different end states. In addition, transmission and distribution upgrade costs to integrate additional generation units were estimated and included to result in a total cost by end state option.

The same assumptions were used in Step A and Step B. The assumptions are summarized in Appendix F, and the major assumptions are presented and discussed in Chapter 4.

Evaluation of end state options across common objectives and selection of desired end state

The evaluation of the five high-level physical design end state options across the common objectives resulted in the selection of *'Balanced portfolio–DG 2.0'* as the desired 2030 physical design.

This option would provide for a robust and diversified renewable portfolio mix that will significantly exceed the 2030 RPS, reduce Hawai'i's dependence on oil, and support a clean energy economy. Market driven DG-PV provides options for our customers. While 'all-in societal costs' were higher than the least cost option, DG 2.0's revised tariff structure would create an equitable rate structure to mitigate the DG cost impact to full service customers who are expected to be the majority of our customer base through 2030.

While the other four end state options were optimized to certain objectives, they were not selected due to other tradeoffs:

- **'Benchmark':** Oil-based fuels make this option costly and is the least favorable for a clean energy future due to highest level of emissions and continued dependence on imported fossil fuels.
- **'Least cost':** This option proves that switching from oil to LNG and higher levels of renewables is favorable for reducing costs; however, due to the limitations on the option for customers to install DG-PV, it is not supportive of expanding and diversified customer energy options.
- **'Balanced Portfolio–DG heavy':** Driven by higher DG-PV prevalence, the end state all-in societal generation and T&D costs are higher than *'Least cost'* and *'Balanced*

portfolio–DG 2.0'. It also puts pressure on the reliability of the system given the high level of variable renewables.

- **'100% renewable':** This is achievable but it also has the highest cost, driven by potential resource constraints on lower cost resources, the required energy storage systems to integrate renewables and maintain an operable system and high cost of biofuels compared to other resources that are required to achieve 100% renewable generation. It also puts pressure on the reliability of the system given the high level of variable renewables.

Strategic findings from the selected desired end state ('Balanced portfolio–DG 2.0')

The above described exercise resulted in the following overall strategic findings related to the desired *'Balanced portfolio–DG 2.0'* physical design of the electric system in 2030:

- The aggregated Renewable Portfolio Standard (RPS) will substantially exceed the RPS mandate of 40% by 2030.
- A balanced portfolio of variable and dispatchable renewables in concert with thermal units offers the most value to customers.
- Converted and new LNG fired thermal units provide critical, efficient and flexible energy resources, ensure the operability and reliability of the grid, enable unit retirements, and can work in combination with variable renewable resources.
- LNG will enable significant fuel saving versus other liquid fuels.
- A combination of distributed and utility-scale resources contribute to the portfolio.
- Under the hypothetical new DG 2.0 tariff structure, aggregated DG-PV capacities across all Companies expected to grow rapidly from the current approximately 330 MW up to approximately 910 MW corresponding to about 15% of the total generation (Hawaiian Electric approximately 650 MW, Maui Electric approximately 135 MW, and Hawai'i Electric Light approximately 115 MW).
- Energy storage will be a key enabling technology for higher renewables while ensuring reliability and resiliency of the system.

STRATEGIC DIRECTION FOR THE DEVELOPMENT OF COMPREHENSIVE TACTICAL MODELS AND PLANS IN STEP B

The objective in Step A was to define the target clean-sheet end state for the physical design in 2030 for the Companies and derive strategic findings and strategic initiatives for future development. In order to realize the desired end state the Companies see the following major strategic initiatives:

- Increase the integration of utility-scale and DG renewable energy resources to exceed the 2030 RPS goal and provide customers with options;
- Diversify the fuel mix to provide lower-cost fuel options and energy service reliability;
- Prepare for LNG and pursue an optimized retirement plan for older oil-fired generation;
- Utilize energy storage to manage increasing integration of variable renewables;
- Expand demand response programs to allow increasing integration of renewables and broadening customer participation;
- Modernize the electric grid to provide greater reliability, minimize costs associated with operating the grid, and enable more renewables and customer energy-management options.

Guided by the strategic findings and directions outlined above, the next step was to translate the selection of 'Balanced Portfolio–DG 2.0' into a detailed tactical plan for each island to transform the existing physical design into the desired end state.

The remainder of this PSIP will further explain Step B and Preferred Plan to achieve the desired physical design, consistent with the above findings.

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3. Current Generation Resources

The Hawaiian Electric Companies provide generation on five islands—O‘ahu, Maui, Moloka‘i, Lana‘i, and Hawai‘i Island—with three utilities and five grids. This accounts for about 90% of all the generation requirements for the entire state of Hawai‘i.

Hawaiian Electric serves 299,528 customers (including those customers who have installed distributed generation to serve their own load while remaining connected to the power grid) on O‘ahu with 1,756 MW (net) of generation.

RENEWABLE RESOURCES

Within the three utilities, the renewable generation varies widely. As of December 31, 2013, Table 3-1 demonstrates that the Hawaiian Electric Companies are far exceeding the Renewable Portfolio Standard (RPS) requirement of 15% by 2015.

Utility	Renewable Portfolio Standard
Hawaiian Electric	28.6%
Maui Electric	44.4%
Hawai‘i Electric Light	60.7%
Consolidated	34.4%

Table 3-1. 2013 Renewable Portfolio Standard Percentages

Renewable Generation

The Companies have a number of clean energy generation units across the service area. Figure 3-1 points outs these units and the island where they are sited.

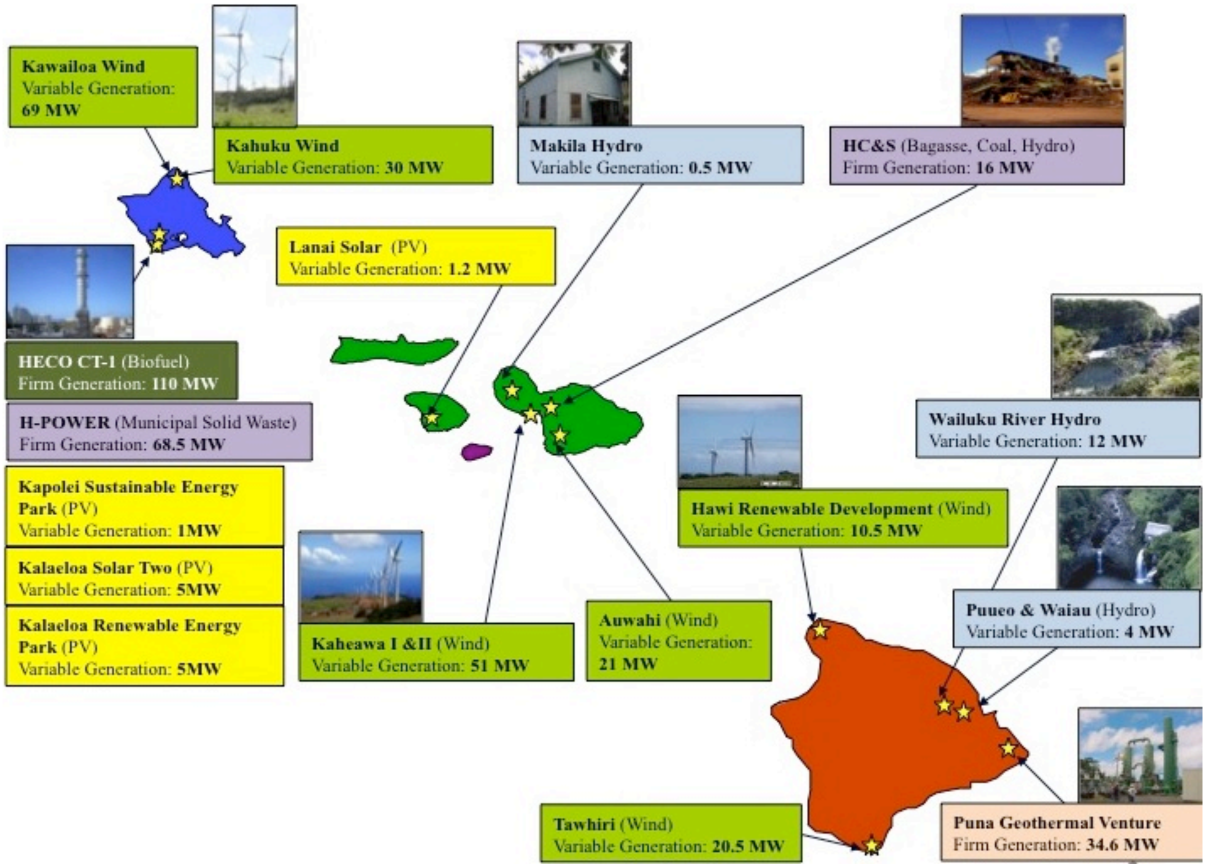

Figure 3-1. Current Clean Energy Resources

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

Renewable Generation Resources

The renewable energy generated by all three operating utilities is comprised of a number of resources. In total, we have attained an RPS of 34.4%.

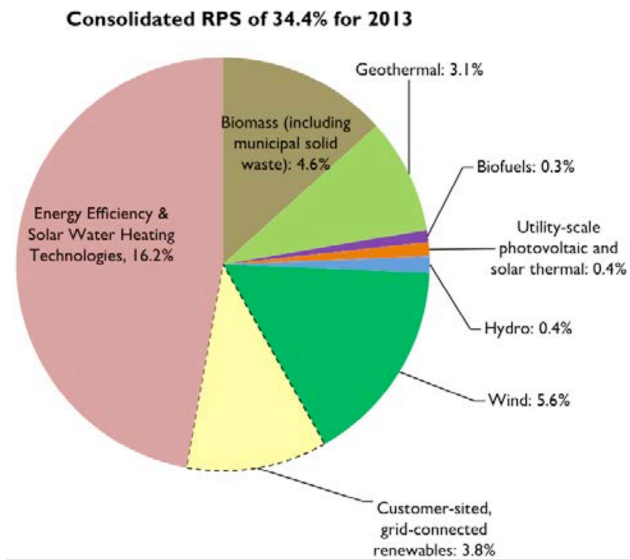

Figure 3-2. Consolidated RPS of 34.4% for 2013

Photovoltaic Installations

The last ten years have witnessed an explosion in PV generation, mostly from individual distributed generation. By the last quarter of 2013, the amount of megawatts generated has grown almost 170 times greater as compared to only seven years earlier (in 2005).

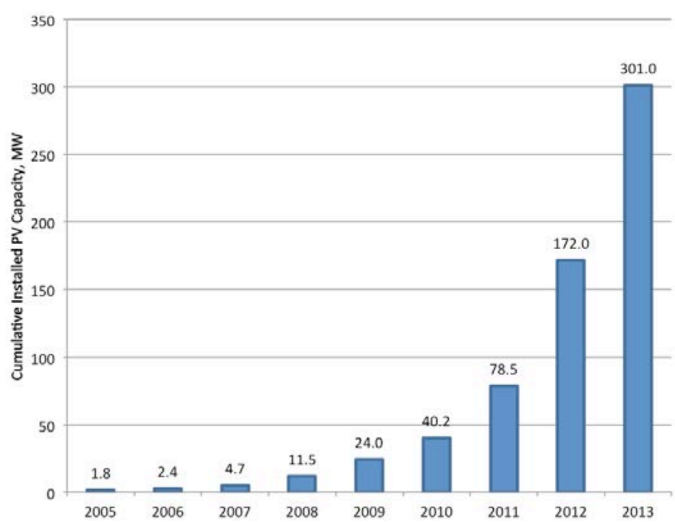

Figure 3-3. Photovoltaic Generation Growth: 2005 through 2013

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

All of our utility-owned generation is summarized in Table 3-2.

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, located in the downtown load center, has two steam units with a combined nameplate capacity of 113 MW, with 107 MW net generation. Both are cycling units. These units were deactivated in January 2014.

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.

Unit	Fuel	Top Load Ratings MW		Start Date	Delivery Type
		Gross	Net		
Kahe					
Kahe 1	LSFO	86.0	82.2	1963	Baseload
Kahe 2	LSFO	86.0	82.2	1964	Baseload
Kahe 3	LSFO	90.0	86.2	1970	Baseload
Kahe 4	LSFO	89.0	85.3	1972	Baseload
Kahe 5	LSFO	142.0	134.6	1974	Baseload
Kahe 6	LSFO	142.0	133.8	1981	Baseload
Total	—	*635.0*	*604.2*	—	—
Waiau					
Waiau 3	LSFO	49.0	47.0	1947	Cycling
Waiau 4	LSFO	49.0	46.5	1950	Cycling
Waiau 5	LSFO	57.0	54.5	1955	Cycling
Waiau 6	LSFO	56.0	53.7	1961	Cycling
Waiau 7	LSFO	87.0	83.3	1966	Baseload
Waiau 8	LSFO	90.0	86.2	1968	Baseload
Waiau 9	LSFO	53.0	52.9	1973	Quick-start
Waiau 10	LSFO	50.0	49.9	1973	Quick-start
Total	—	*491.0*	*474.1*	—	—
Honolulu					
Honolulu 8	LSFO	56.0	53.4	1954	Deactivated
Honolulu 9	LSFO	57.0	54.3	1957	Deactivated
Total	—	*113.0*	*107.6*	—	—
Campbell Industrial Park (CIP)					
CT-1	Biodiesel	113.0	112.2	2009	Peaker
Totals	—	*1,352.0*	*1,298.1*	—	—

Table 3-2. Oʻahu Utility-Owned Generation Units

IPP Generation

H-Power

The Honolulu Program of Waste Energy Recovery — H-Power — is a municipal solid waste refuse to energy plant that generates 68.5 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.

Kalaeloa Renewable Energy Park and Kalaeloa Two

Together, these two solar photovoltaic installations generate 10 MW of variable renewable generation.

Unit	Fuel	Net MW	Delivery Type
H-Power	Refuse	68.5	Baseload
AES	Coal	180.0	Baseload
Kalaeloa	LSFO	208.0	Baseload
Kahuku Wind	Wind	30.0	Variable
Kapolei Sustainable Energy Park	PV	1.0	Variable
Kawailoa	Wind	69.0	Variable
Kalaeloa Renewable Energy Park	PV	5.0	Variable
Kalaeloa Two	PV	5.0	Variable
Total	—	*566.5*	—

Table 3-3. O‘ahu IPP Generation Units

Hawaiian Electric Renewable Generation

Compared to a 4.7% RPS attainment in 2010, Hawaiian Electric has more than doubled the amount of renewable energy to 11.7% in 2013.

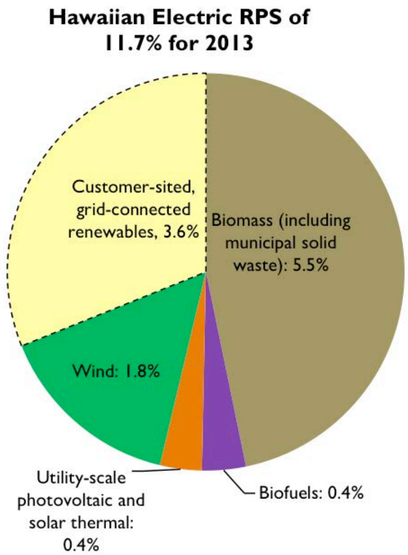

Figure 3-4. 2013 Hawaiian Electric RPS Percent for 2013

HAWAIIAN ELECTRIC DISTRIBUTED GENERATION

Distributed generation, mostly photovoltaics, are being installed by our customers on many of our distribution feeders. The growth of PV systems has been exponential on all of our major islands. All three operating utilities are in the Solar Electric Power Association's top 10 PV per capita. The accompanying maps show just how "distributed" the distributed generation on the island are, and the transmission and distribution challenges this presents.

Distributed generation on O'ahu currently exceeds 200 MW total nameplate capacity. This is about the size of one of our largest power plants.

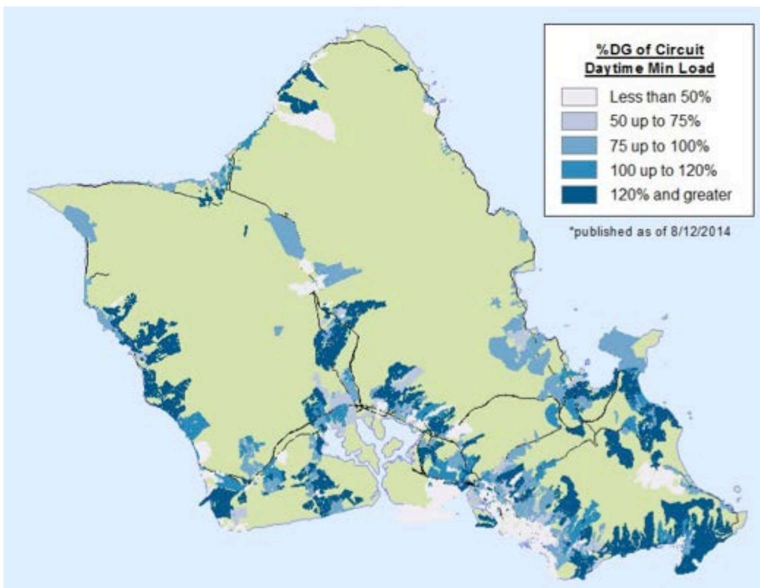

Figure 3-5. Distributed Generation Map of O'ahu

O'AHU–MAUI GRID INTERCONNECTION

For several years, the idea of inter-island cables between O'ahu and the neighbor islands have been discussed. An interisland cable would involve developing a High Voltage Direct Current (HVDC) submarine cable interconnection between islands. Submarine HVDC systems utilize a mature technology with very high service reliability. There are many such systems in operation around the world.

There are two fundamental purposes for such interconnections:

- Increase renewable energy penetration for O'ahu: One of the state of Hawai'i's major goals is to increase renewable generation. The majority of the state's population, and thus the majority of the Hawaiian Electric Companies' system load, is on O'ahu. Conversely, much of the best renewable resource potential is on the neighbor islands, particularly Maui County and Hawai'i Island.
- Increase the overall operating efficiencies of the O'ahu and Maui power systems: It may be possible to improve the efficiencies of the O'ahu and Maui systems by jointly dispatching the two systems utilizing an interconnection.

The use of a submarine cable to interconnect remote renewable generators to O'ahu makes sense only if sufficient renewable resources cannot be sourced on O'ahu. In the Preferred Plan, it appears that the 40% RPS goal by 2030 can be met with a combination of additional wind, utility-scale solar and biofuels, without the need to import renewable generation from other islands. Therefore, for purposes of this PSIP, the Companies have not considered HVDC submarine cables to access additional renewable resources. If in the future, this key planning assumption proves to be incorrect, an inter-island cable could become feasible for this purpose. This planning assumption does not preclude proposals for neighbor island-sited renewable generation to serve O'ahu through a submarine cable, provided that such proposals are cost effective and reliable, relative to other options available to Hawaiian Electric.

With respect to the benefits of using interisland cables to achieve joint dispatch benefits between the Hawaiian Electric and Maui Electric systems, the PSIP analyses did include an evaluation of an interconnection between O'ahu and Maui.

O'ahu–Maui Interconnection Specifications

The assumed O'ahu–Maui interconnection configuration for purposes of the PSIPs is two (HVDC) cables, each with a load carrying capacity of 100 MW. The 100 MW maximum size for each circuit was assumed in order to keep the single largest generating contingency at 100 MW, or roughly the same size as the largest unit in the O'ahu system. The cable is assumed to be bi-directional: power can flow in either direction. Such a cable system would consist of:

- Two submarine HVDC cables installed between O'ahu and Maui, with separate landfall and interconnection points on either end of the cable.
- Four 100 MW each AC/DC converter stations (one for each end of each HVDC circuit); and AC interconnection facilities and system upgrades as necessary in the Hawaiian Electric and Maui Electric systems to interconnect the HVDC interisland cable system.
- All overheads necessary to site, permit, design, construct and operate the HVDC interisland cable system.

Interisland Cable Feasibility Analysis Approach

The feasibility of utilizing an interisland cable for joint dispatch of the Hawaiian Electric and Maui Electric systems was evaluated by comparing:

- The net present value of system production costs with the Hawaiian Electric and Maui Electric systems assumed to be interconnected in a manner that allows economic dispatch of generation on both islands; to
- The sum of the present value of system production costs for each of the Hawaiian Electric and Maui Electric systems.

The difference between these two cases provides the gross benefit that could be provided by an interisland cable system that enables joint dispatch. This represents the higher bound of what an interisland cable could cost and still be economically feasible. This value was then compared to known cost estimates for an O'ahu–Maui interisland HVDC cable system[13].

Using this methodology, it is not necessary to estimate the cost of this particular cable configuration. Instead, the differential computed above can be compared to known cost estimated for this proposed project. If the benefits are substantially less that the lowest interisland cable cost estimate known to date, then a cable is not economically feasible at this time. If on the other hand, the difference approaches the known cost estimate levels, then further analysis must be performed. This is a conservative approach since the existing cost estimates are for a single 200 MW HVDC system; a system with two 100 MW HVDC circuits is likely to be substantially more expensive (and complicated in terms of permitting) given the need for two routes, and two cable installations.

[13] The lowest know cost estimate for an interconnection between the Maui and O'ahu systems is $600,000,000, provided by NextEra Energy Hawai'i LLC on September 9, 2013 in Docket No. 2013-0169.

EMERGING RENEWABLE GENERATION TECHNOLOIGES

The Hawaiian Electric Companies considered many different renewable energy resources in our analyses for creating the PSIPs. Some of these renewable resources are currently commercially available, while others are emerging. Rather than consider the best available projections for these emerging technologies, we have based our PSIPs on readily available renewable energy resources. These include:

- Utility-scale simple-cycle combustion turbines
- Utility-scale combined-cycle combustion turbine and steam generator combinations
- Biomass and waste-fueled steam generation
- Internal combustion engine generation
- Geothermal generation
- Onshore utility-scale wind generation
- Utility-scale and small-scale solar photovoltaic generation
- Run-of-river hydroelectric
- Pumped storage hydroelectric

Several other commercially available generation technologies were also not considered appropriate for inclusion in our PSIPs (such as nuclear energy and storage hydroelectric).

Determining Commercial Readiness

The Australian Renewable Energy Agency (ARENA) developed a Commercial Readiness Index (CRI) and released it in February 2014. We used the CRI to evaluate emerging generation options for the PSIPs because we found the CRI provided practical, objective and actionable guidance.

The CRI rates the commercial readiness level of a particular technology on a scale from 1-lowest level of readiness to 6-bankable. (See Appendix H: Emerging Renewable Technologies for more details on the rating scale.) In general, the CRI finds technologies commercially ready when:

- The technology has been implemented in a commercial setting and meets its intended need.
- The technology has been sited, permitted, built, and operated at full scale; and these challenges are well understood.

- The electricity industry, in general, accepts the performance and cost characteristics of the technology.
- Well capitalized engineering procurement construction vendors willingly provide cost and performance guarantees around an asset that uses the technology.
- A service, repair and parts system exists to support the technology.
- Financial institutions willingly accept the performance risk when underwriting technology projects.

We only considered commercially ready technologies (CRI level 5 or 6) in our PSIP modeling analyses.

Technologies Not Commercially Ready

A number of emerging—although not commercially ready— generation technologies have been proposed for our Hawaiʻi power grids, including ocean wave, tidal power, ocean thermal energy storage (OTEC), and concentrated solar thermal power (CSP). See Appendix H: Emerging Renewable Technologies for details on these technologies.)

Two of these technologies hold much promise.

Ocean Thermal Energy Conversion (OTEC). Hawaiʻi is a pioneer in OTEC research, having demonstrated the first successful OTEC project on Hawaiʻi Island in the 1970s. Despite the technological promise of OTEC for large-scale electricity generation, no full-scale OTEC plant has yet to be built anywhere in the world. Hawaiian Electric is currently in power purchase negotiations with OTEC International (OTECI) for an OTEC facility to provide power to the island of Oʻahu. In order to prove commercial readiness, OTECI would be required to complete and operate a 1 MW demonstration plant for an agreed period of time, and if successful, conduct additional incremental testing of the full-scale facility prior to full operation.

Wave/Tidal Power. Successful demonstration tidal and wave power projects have been implemented in several locations, including Hawaiʻi. We currently partner with the U.S. Navy (and others) in a small scale pilot. Small utility-scale wave power projects have been installed in Europe. Implementing large-scale tidal and wave installations has thus far been hampered by a lack of understanding of the associated siting and permitting challenged. Thus, tidal and wave power generation remains not commercially ready.

Technology Planning Assumptions versus Policy Considerations

While we limited our PSIPs plan to currently available technologies, we remain open to including future renewable technologies in our generation resource mix—when they become commercially available. We also remain open to installing pilot and demonstration projects for these and any other viable emerging renewable technology.

We welcome responses to our procurement Request for Proposals (RFPs) that include emerging technologies, and pledge to evaluate these responses on their merits. Evaluation factors can include:

- Commercial readiness of the proposed technology.
- Community acceptance of the project proposed.
- Viability of its siting, licensing, permitting, and construction.
- Realistic site-specific costs.

Factors deemed relevant to the specific project and technology will also be included in our evaluation.

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4. Major Planning Assumptions

The Hawaiian Electric Companies created this PSIP based, in parts, on a realization of the current state of the electric systems in Hawai‘i, forecast conditions, and reasonable assumptions regarding technology readiness, availability, performance, applicability, and costs. As a result, this plan presents a reasonable and viable path into the future for the evolution of our power systems. We have attempted to document and be fully transparent about the assumptions and methodologies utilized to develop this plan. We recognize, however, that over time these forecasts and assumptions may or may not prove to be accurate or representative, and that the plan would need to be updated to reflect changes. As we move forward, we will continually evaluate the impacts of any changes to our material assumptions, seek to improve the planning methodologies, and evaluate and revise the plan to best meet the needs of our customers.

The PSIP analyses were conducted using production simulation planning tools that employ industry-accepted algorithms and methodologies (see Appendix C). These tools require the utility planner to develop a set of assumptions and data that allow for consistent analysis of various scenarios of interest. Figure 4-1 is a generalization of the categories of input assumptions and data that is required for production simulation analysis.

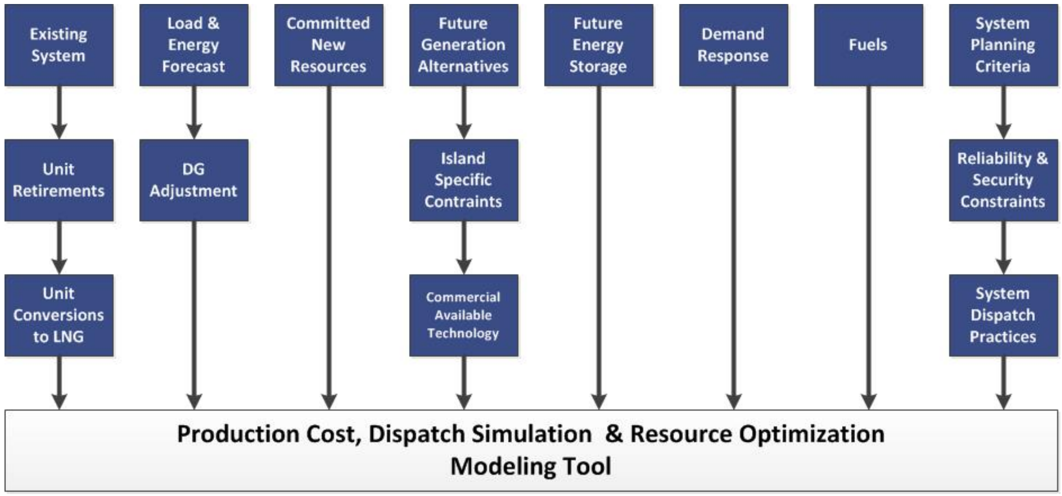

Figure 4-1. PSIP Production Simulation Model Input Hierarchy

This Chapter 4 summarizes the assumptions and data use to develop the scenarios and the results presented in this PSIP. Appendix F: Modeling Assumptions Data contains more detailed quantitative assumptions and data used in the analyses.

EXISTING POWER SYSTEMS

The starting point for a long-range planning analysis is the existing state of the Companies' individual power systems.

General System Descriptions

Hawaiian Electric: As of the end of 2013, the existing Hawaiian Electric power system on O'ahu consists of 1,298 MW of utility-owned generating capacity, 457 MW of firm Independent Power Producer (IPP) capacity, and 110 MW of variable renewable IPP capacity. There was approximately 167 MW of installed net energy metering capacity from renewable energy technologies (mainly photovoltaic) and 10 MW of installed feed-in tariff (FIT) capacity. Hawaiian Electric operates 215 circuit miles of overhead 138,000 volt (also expressed as 138 kilovolts or 138 kV) transmission lines and 8 miles of underground transmission lines, 537 circuit miles of overhead and underground 46 kV sub-transmission lines, 2,231 circuit miles of overhead and underground distribution lines (nominal distribution voltages of 4.16 kV, 12.47 kV, and 25 kV), 21 transmission substations, and 131 distribution substations.

Maui Electric: As of the end of 2013, the existing Maui Electric power system on Maui consists of 243 MW of utility-owned generating capacity, 16 MW of firm IPP capacity, and 72.5 MW of variable renewable IPP capacity. Maui Electric's system on Lana'i has

10.23 MW of company-owned thermal generation, and 1.2 MW of variable IPP capacity. Maui Electric's system on Moloka'i has 12.01 MW of utility owned capacity. There was approximately 35 MW of installed net energy metering capacity, and 2 MW of feed-in tariff capacity within Maui Electric's service area. Maui Electric operates 250 miles of 69 kV and 23 kV transmission lines and a 34.5 kV on Moloka'i, 8 transmission-level substations, 71 distribution substations, and 1,520 miles of 12.47 kV, 7.2 kV, 4.16 kV, and 2.4 kV distribution lines.

Hawai'i Electric Light: As of the end of 2013, the existing Hawai'i Electric Light power system on Hawai'i Island consists of 195 MW of utility-owned thermal generating capacity, 94.6MW of firm IPP capacity, 4.5 MW of utility-owned variable generation and 43.1 MW of variable renewable IPP capacity. There was approximately 33 MW of installed net energy metering, and 1 MW of feed-in tariff capacity. Hawai'i Electric Light operates 641 miles of 69 kV transmission lines, 22 transmission-level substations, 78 distribution substations, and 4,080 miles of 13.2 kV distribution lines.

Table 4-1 contrasts the nature of each of the three operating systems in terms of customer density expressed in customers per mile of distribution circuit.

Utility	Number of Customers (12/31/13)	Distribution Circuit Miles	Customers Per Mile of Distribution Line
Hawaiian Electric	299,528	2,231	134.3
Maui Electric	69,577	1,520	45.8
Hawai'i Electric Light	82,637	4,080	20.3

Table 4-1. Customers per Mile of Distribution Line by Operating Company

Existing Generation Units & Retirement Dates

The list of the Companies' existing units is provided in Chapter 3. The retirement dates of the Companies' existing generating units, if applicable, are provided in the discussion of the Preferred Plan in Chapter 5.

Liquefied Natural Gas (LNG) Unit Conversion

In the Preferred Plan, it was assumed that certain of the Companies' units would be converted to LNG during the planning period.

Hawaiian Electric

- Kahe 1–6 converted to use LNG beginning in 2017
- Waiau 5–10 converted to use LNG beginning in 2017
- Kalaeloa (IPP) converted to use LNG beginning in 2017 (at Company expense).

Maui Electric

- Maʻalea 14, 15, 16, 17, 19 converted to use LNG beginning in 2017
- Waena internal combustion engine (ICE) units (relocated from South Maui) converted to use LNG beginning in 2024.
- Waena Internal Combustion Engine (ICE) units relocated from South Maui and converted to use LNG beginning in 2024.

Hawaiʻi Electric Light

- Puna CT3, Keahole Combined Cycle Units (CT4, CT5) converted in 2017
- Hamakua Energy Partners (HEP) (IPP) converted (at Company expense) to use LNG in 2018.

Existing Independent Power Producer (IPP) Contract Assumptions

During the planning period, assumptions were made regarding how certain IPP contracts would be renewed, cancelled, or renegotiated during the planning period. Existing IPP contracts expiring within the study period were assumed to continue past the expiration date of the current contract, and switch to the modeled resource pricing at the time of expiration as shown in Appendix F (on January 1 of the next year for modeling purposes). These IPPs were assumed to retain present curtailment priority and methodology. These are planning assumptions only; the dispositions of the Companies' contracts with IPPs are subject to the terms of the existing PPAs, and/or the ability of the third parties and the Company to reach mutual agreement (subject to the Commission's approval) on pricing, terms, and conditions applicable beyond the expirations of the current PPAs.

Hawaiian Electric

- The Kalaeloa Energy Partners PPA was assumed to be extended at the end of its contract term (May 23, 2016) for six years, to 2022. At its expiration in 2022, the PPA was assumed to the renegotiated, subject to competitive procurement, and extended past the PSIP planning period.
- The AES Hawai'i PPA was assumed to be renegotiated, subject to competitive procurement, at the end of its contract term (September 1, 2022), and extended past the end of the PSIP planning period, at its full 180 MW capacity, but with a mix of 50% coal and 50% biomass for fuel.

Maui Electric

- The HC&S PPA was assumed terminated on 12/31/18 based on expected efforts to negotiate and extend the current agreement, subject to Commission approval.
- Kaheawa Wind Power (KWP) was assumed to continue at current nameplate capacity beyond the end of its current contract in 2026, but will be paid according to pricing identified in Appendix F.
- Makila Hydro will continue at current nameplate capacity beyond the end of its current contract in 2026. For purposes of this report, the Makila Hydro payment, from January 2015 to December 2026, is assumed to be fixed at Maui Electric's August 2014 Avoided Cost per Docket No. 7310. For the period of 2027 to 2030 Makila Hydro will be paid according to pricing identified in the Appendix F.

Hawai'i Electric Light

- Conversion of HEP to LNG in 2018.
- Hawi Renewable Development (HRD) – was assumed to continue at current name plate capacity beyond the end of its current contract in 2021, but will be paid according to pricing identified in Appendix F.
- Wailuku River Hydro – was assumed to continue at current nameplate capacity beyond the end of its current contract in 2023, but will be paid according to pricing identified in Appendix F.
- Tawhiri - was assumed to continue at current nameplate capacity beyond the end of its current contract in 2027, but will be paid according to pricing identified in Appendix F.
- Puna Geothermal Ventures (PGV) - was assumed to continue at current name plate capacity beyond the end of its current contract in 2027, but will be paid according to pricing identified in Appendix F.

Committed New Resources

The Companies have made certain commitments regarding new resource additions. Several of these resource commitments have received Commission approval. Others are the still subject to Commission review and approval.

Hawaiian Electric

The following future generating resources are considered to be committed for planning purposes, and are therefore included in the Base Plan and Preferred Plan for Hawaiian Electric:

- Waiver Projects: 244 MW of multiple IPP-developed solar PV projects that are being negotiated pursuant to the waivers from the framework for competitive bidding in Dockets Nos. 2013-0156 and 2013-0381. Each separate PPA for the waiver projects will require Commission approval. These projects will contribute to the Companies' RPS requirements. These projects are assumed to enter service by the end of 2016.
- Na Pua Makina Wind: 24 MW IPP-owned wind energy generation facility project near the community of Kahuku on the north shore of O'ahu. This project is assumed to enter service by the end of 2016. This project will contribute to the Companies' RPS requirements. Approval of the PPA for this project is pending in Docket No. 2012-0423.
- Mililani South Solar: 20 MW IPP-owned utility-scale solar PV project facility near Mililani, O'ahu. This project is assumed to enter service by the end of 2016. This project will contribute to the Companies' RPS requirements. Approval of the PPA for this project is pending in Docket No. 2014-0077.
- Kahe Solar PV: 11.5 MW utility-scale solar PV project that is being developed by the Hawaiian Electric at the Kahe generating station site. This project is assumed to enter service by the end of 2016. This project will contribute to the Companies' RPS requirements. Approval of this project is pending in Docket No. 2013-0360.
- Schofield Generating Station: 50 MW total, consisting of six separate reciprocating engines each having a generating capacity of 8.4 MW. Schofield Generating Station will utilize at least 50% biodiesel and will contribute to the Companies' RPS requirements. Approval of this project is pending in Docket No. 2014-0113. This project is assumed to enter service during 2017.

Maui Electric

There are no committed resources for Maui Electric at the present time. It is assumed that Maui Electric will issue an RFP in 2015 for new generation to become available in 2019.

Hawai‘i Electric Light

The following future generating resources are considered to be committed and are therefore included in the base plan for Hawai‘i Electric Light:

- Hu Honua: 21.5 MW biomass IPP-owned project at Pepe‘ekeo, Hawai‘i Island. The PPA for this project was approved by the Commission in Docket 2012-0212, pursuant to Order No. 31758, issued on December 20, 2013. This project will contribute to the Companies’ RPS requirements. This project is assumed to enter service in 2015.

- Geothermal RFP: Hawai‘i Electric Light has to committed to modeling 25 and 50 MW of new IPP-owned geothermal projects and to issue a Request for Best and Final Offers for at least 25 MW. Pursuant to Commission Order in Docket No. 2012-0092, the Request for Best and Final Offers shall be filed no later than September 25, 2014 for Commission review and approval.

CAPACITY VALUE OF VARIABLE GENERATION AND DEMAND RESPONSE

Wind and solar are variable generating resources. Therefore, determining their capacity value (that is, the variable resource’s ability to replace firm generation) with a high level of confidence is a considerable challenge. However this determination is a critical exercise in order to ensure that customer demand is met and system reliability is maintained.

Capacity Value of Wind Generation

The determination of when additional firm capacity is needed is, in part, based on the application of Hawaiian Electric’s generating system reliability guideline, which is 4.5 years per day loss of load probability (LOLP). The capacity value of existing and future wind resources is determined through an LOLP analysis that incorporates this guideline. The wind resources’ contribution to serving load is reflected in the LOLP calculations. Accordingly, wind resources’ contributions to capacity are dependent upon the composition and assumptions in each plan. Future LOLP analyses that incorporate additional wind resources may affect the actual capacity value of existing wind resources.

Hawaiian Electric

Based on historical 2013 O‘ahu wind data, the aggregate capacity value of the two existing wind farms (30 MW Kahuku Wind and 69 MW Kawailoa Wind) determined through an LOLP analysis is approximately 10 MW, or about 10% of the nameplate value of the existing wind resources.

Maui Electric

The aggregate value of the three existing wind farms (20 MW Kaheawa Wind Power I, 21 MW Kaheawa Wind Power II, 21 MW Auwahi Wind Energy) contribution to capacity planning is 2 MW based on historical examination of available wind capacity during the peak period hours to derive an amount which is probable during that period.

The capacity value of future wind farms for PSIP modeling purposes is 3% of the nameplate value of the facility to be added.

Hawai‘i Electric Light

The aggregate capacity planning value of the two existing wind farms (20.5 MW Tawhiri wind farm and 10.56 MW Hawi Renewable Development wind farm) is 3.1 MW. This is based on an historical examination of available wind capacity during the peak period hours to derive an amount that is probable during the historical period. The capacity value of the hydro facilities was 0.7 MW using the same methodology used to determine the capacity value of wind.

The capacity value of future wind farms for PSIP modeling purposes is 10% of the nameplate value of the facility to be added.

Capacity Value of Solar Generation

The capacity value of existing and future utility-scale and rooftop PV is 0, using the same capacity valuation methodology used for the wind and hydro resources. This result is driven by the fact that variable PV does not produce during the utility’s peak periods (that is, evenings). It is the utility’s net peak demand that determines the need for additional capacity.

Capacity Value of Demand Response

The estimated megawatt potential from the Residential and Small Business Direct Load Control Program, Commercial and Industrial Direct Load Control Program, Customer Firm Generation Program, and Time-of-use Programs are included in PISP capacity planning based on the *Integrated Demand Response Portfolio Plan*.[14]

[14] The Companies filed its *Integrated Demand Response Portfolio Plan* (IDRPP) with the Commission on July 28, 2014.

LOAD AND ENERGY PROJECTION METHODOLOGY

The purpose of the load (or demand) and sales (energy) forecasts in a planning study is to provide the peak demands (in MW) and energy requirements (in GWh) that must be served by the Company during the planning study period. Forecasts of peak demand and energy requirements must take into account economic trends and projections and changing end uses, including emerging end-use technologies.

The methodology for arriving at the net peak demand and energy requirements to be served by the Company begins with the identification of key assumptions such as the economic outlook, analysis of existing and proposed large customer loads, and impacts of customer-sited technologies such as energy efficiency measures and customer-owned distributed generation. Impacts from emerging technologies such as electric vehicles are also considered as they can significantly impact sales in the future.

Sales Forecast

The underlying economic sales forecast is derived first by using econometric methods and historical sales data excluding impacts from energy efficiency measures or customer-sited distributed generation ("underlying economic sales forecast"). Estimates of impacts from energy efficiency measures, customer-sited distributed generation through the Company's tariffed programs and electric vehicles (referred to as "layers") were then used to adjust the underlying economic sales forecast to arrive at the final sales forecast.

Peak Forecast

The Hawaiian Electric peak forecast is derived using Electric Power Research Institute's Hourly Electric Load Model (HELM). Maui and Hawai‘i Electric Light use Itron Inc.'s proprietary modeling software, MetrixLT. Both software programs utilize load profiles by rate schedule from class load studies conducted by the Company and the sales forecast by rate schedule. The rate schedule load profiles adjusted for forecasted sales are aggregated to produce system profiles. The Company employed the highest system demands to calculate the underlying annual system peaks. The underlying peak forecast for Lana‘i and Moloka‘i Divisions were derived by employing a sales load factor method that compares the annual sales in MWh against the peak load in MW multiplied by the number of hours during the year. After determining the underlying peak forecast, the Company made adjustments that were outside of the underlying forecasts, for example impacts from energy efficiency measures. No adjustments were made to the underlying system peak forecast for customer-sited distributed generation or electric vehicles as forecasted system peaks are expected to occur during the evening. It was assumed most of the distributed generation would be PV systems without batteries and electric vehicle charging was not expected to significantly affect the evening peak.

Customer-Sited Distributed Generation

The projections for impacts associated with customer-sited distributed generation were developed separately for residential and commercial customers and aggregated into an overall forecast for distributed generation, predominantly PV systems. Eligible market size was based on technical penetration limits, absolute sizes of customer classes, and future growth assumptions. In the near term (through 2016) a set rate of interconnections under the existing company tariffs were used based on simplified assumptions about queue release and the pace of new applications. Beyond 2016 the Company assumed that a new distributed generation tariff structure (DG 2.0) would be implemented across all customer classes. Benchmarked relationships between the payback period of PV systems and customer uptake rates, projected market demand for new PV systems among all residential and commercial customer classes were applied to installed PV capacity as of year-end 2016 as a starting point for the long term. For purposes of modeling, PV energy production levels for hourly or sub-hourly information are derived from actual solar irradiance field data. Consistent with the *Distributed Generation Interconnection Plan* (DGIP), beyond 2016, DG PV is assumed to provide active power control and is therefore curtailable during periods when the system cannot accept excess DG energy. The DG curtailment priority is assumed to be senior to transmission-connected utility-scale resources, that is, DG is curtailed after utility-scale resources are curtailed.

Energy Efficiency

The projections for impacts associated with energy efficiency measures are consistent with impacts achieved by the Public Benefits Fund Administrator, Hawaiʻi Energy, over the next five to ten years. The Company assumed that it would take several years before changes to building and manufacturing codes and standards are integrated into the marketplace. Following these types of changes, the impacts would grow at a faster pace in order to meet the longer term energy efficiency goals (expressed in GWh) identified in the framework that governs the achievement of Energy Efficiency Portfolio Standard (EEPS) in the State of Hawaiʻi as prescribed in Hawaiʻi Revised Statutes § 269-96 and set by the Commission in Decision and Order No. 30089 in Docket No. 2010-0037.

Electric Vehicles

The development of the electric vehicles forecast 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. As with any emerging technology, estimating impacts are challenging because the technology is so new and historical adoption and impact data is limited.

Demand and Energy Requirements

The demand served and energy generated by the Company is greater than the demand and energy requirements at the customer's location (net of the amount conserved or self-supplied) due to energy losses that occur in the delivery of power from a generator to a customer. Customer level demand and energy forecasts are increased accordingly to account for these losses.

The net results are the quantities of demand and energy that must be supplied from the Company's generating fleet, including assets owned by the Company and assets owned by third parties who sell to the Company under Power Purchase Agreements (that is, utility-scale independent power producers).

Peak Demand Forecasts

The peak demands of each operating Company forecasted through the study period (expressed at the net generation level) are shown in Figure 4-2 through Figure 4-6.

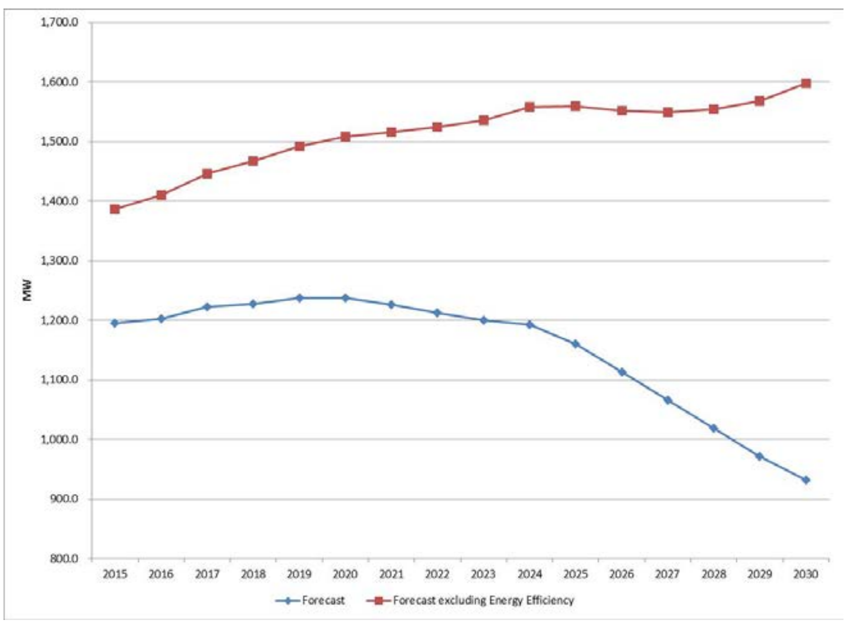

Figure 4-2. Hawaiian Electric Peak Demand Forecast (Generation Level)

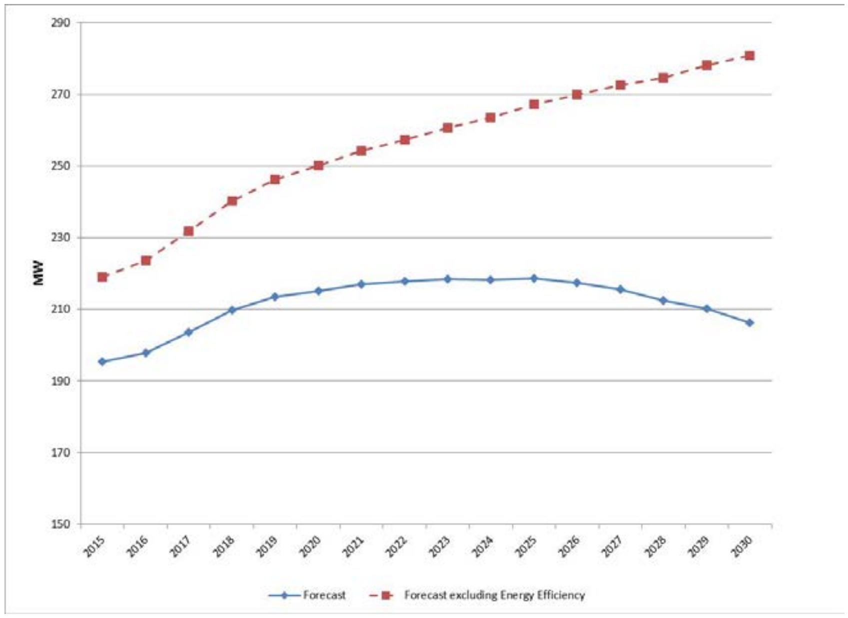

Figure 4-3. Maui Peak Demand Forecast (Generation Level)

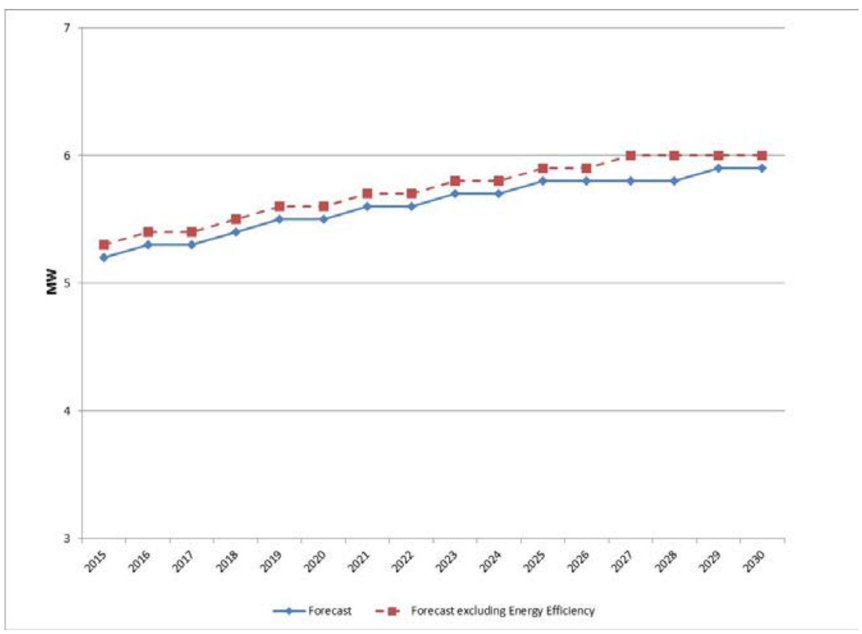

Figure 4-4. Lana‘i Peak Demand Forecast (Generation Level)

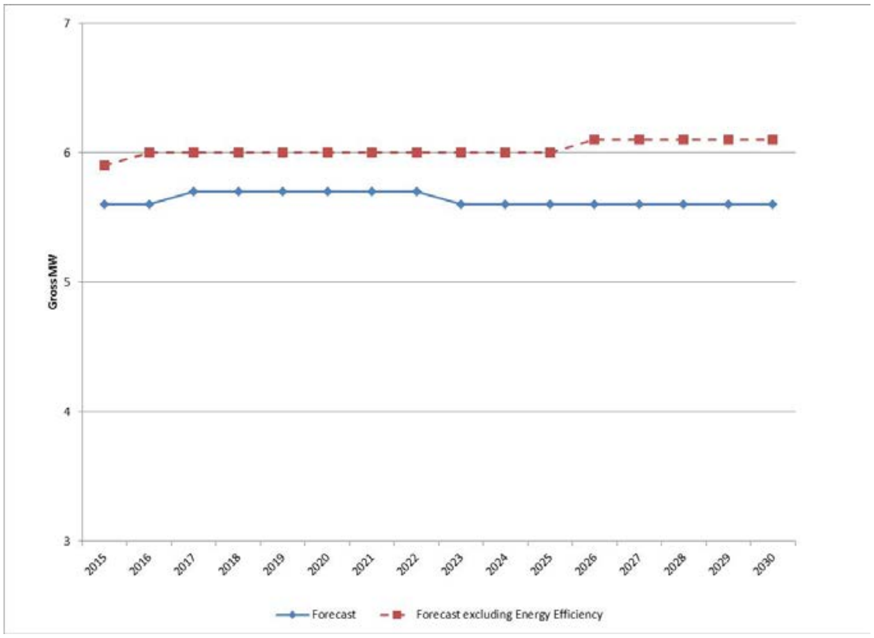

Figure 4-5. Moloka'i Peak Demand Forecast (Generation Level)

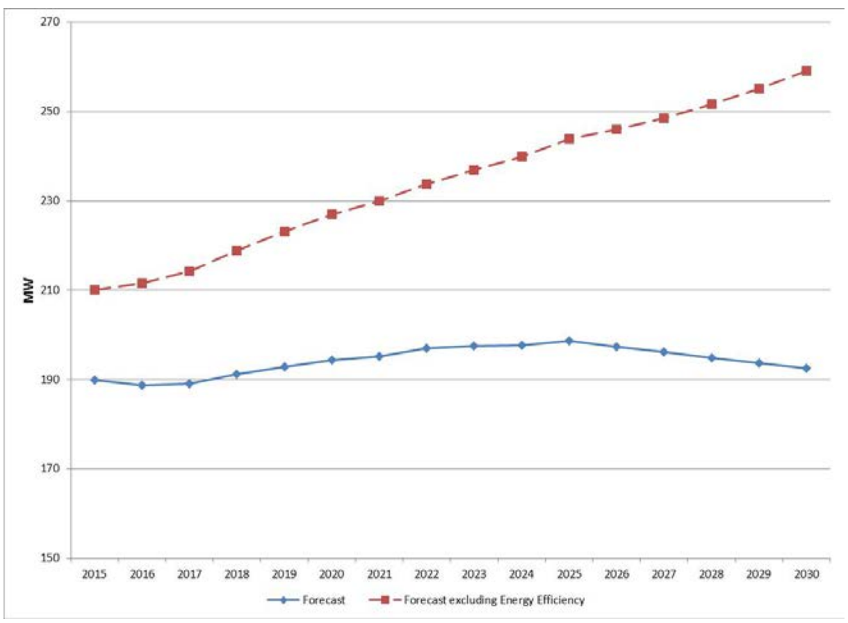

Figure 4-6. Hawai'i Electric Light Peak Demand Forecast (Generation Level)

Energy Sales Forecasts

The forecasts of energy requirements to be served by each operating Company through the study period (expressed at the customer level) are shown in Figures 4-7 through 4-11.

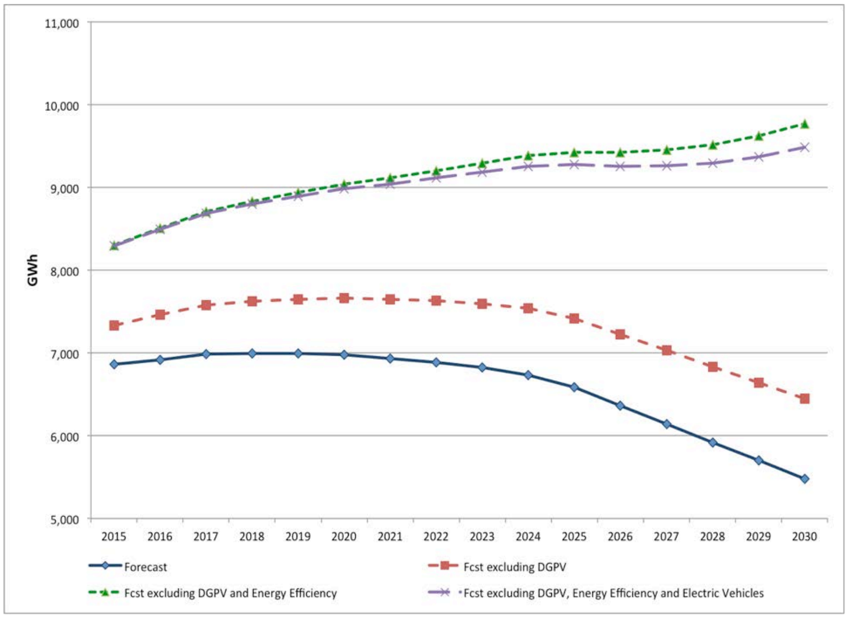

Figure 4-7. Hawaiian Electric Energy Sales Forecast (Customer Level)

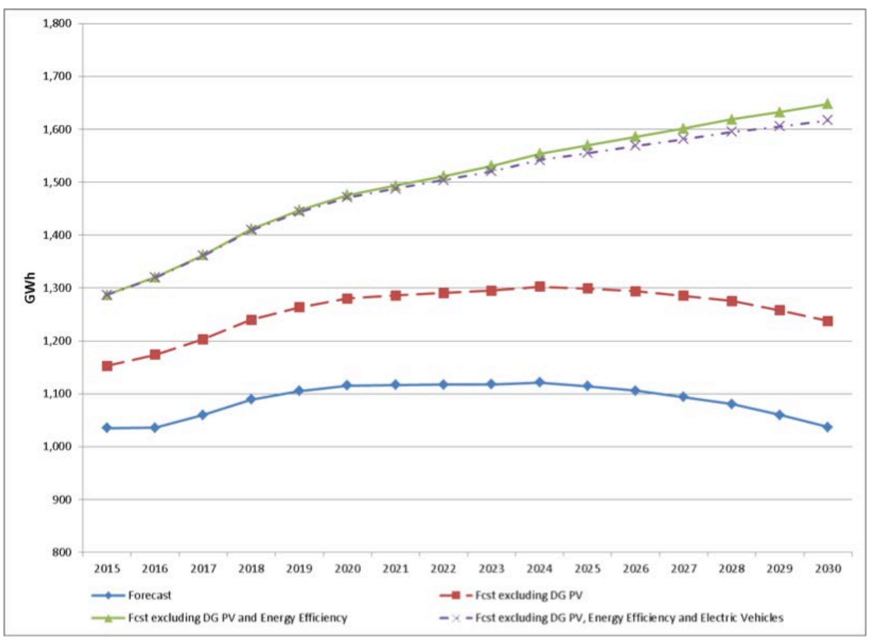

Figure 4-8. Maui Energy Sales Forecast (Customer Level)

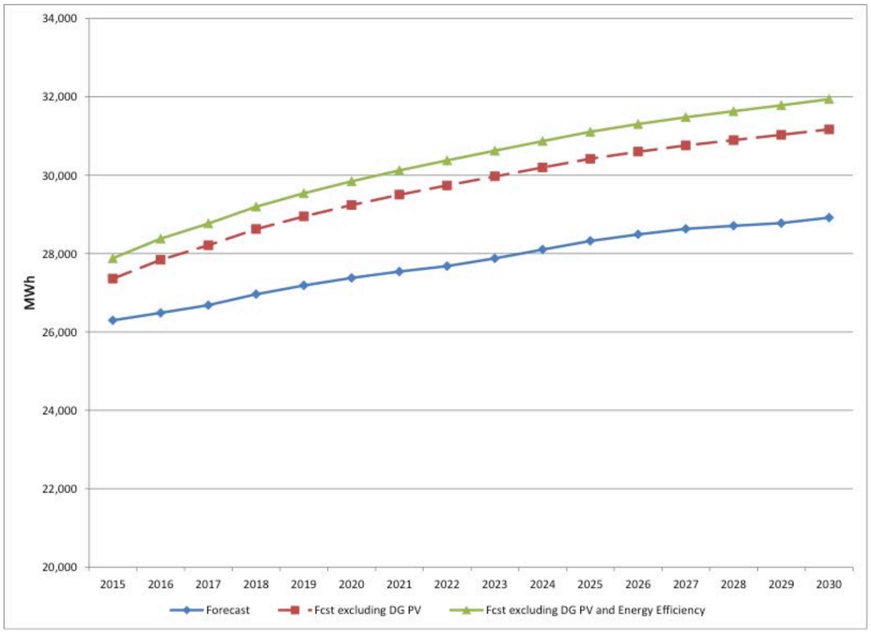

Figure 4-9. Lana'i Energy Sales Forecast (Customer Level)

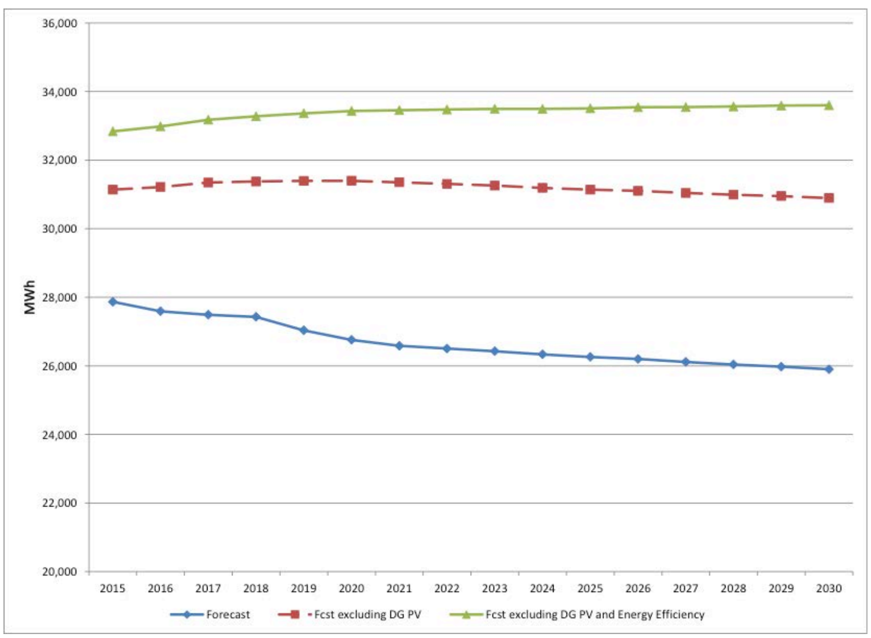

Figure 4-10. Moloka'i Energy Sales Forecast (Customer Level)

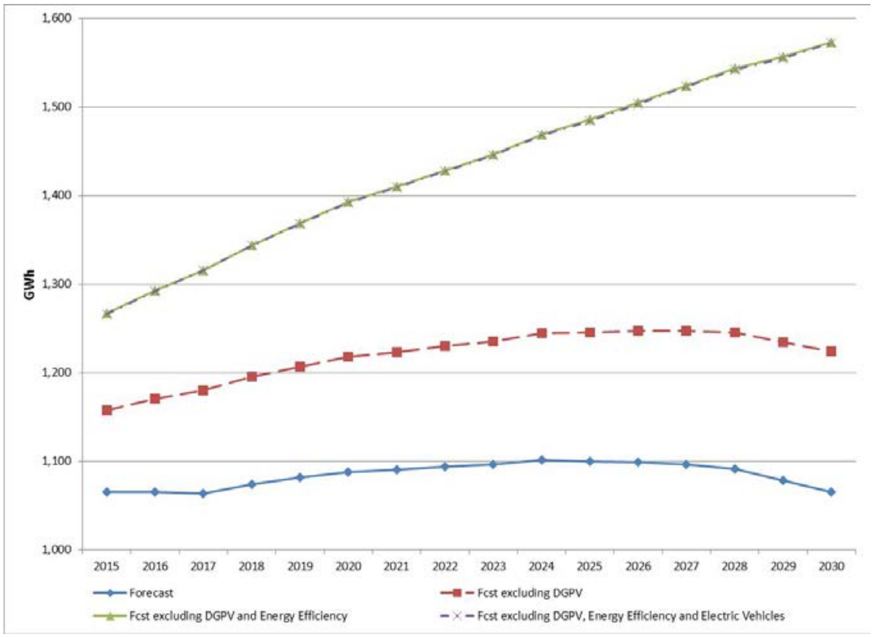

Figure 4-11. Hawai'i Electric Light Energy Sales Forecast (Customer Level)

It is important to note that both the net peak demand and the net energy requirements, which the Company is obligated to serve, are relatively flat and even decline toward the end of the study period. This is the result of energy efficiency and an assumed future level of customer-owned distributed generation (mostly distributed solar PV).

In addition to the forecasts described above, the Company incorporated the effects of implementing dynamic and critical peak pricing programs. Load shifting and energy savings could be realized through the implementation of these programs. Hourly load adjustment factors were based upon the application of demand elasticity adjustments to assumed time of use rate structures. Refer to Chapter 4 of the Integrated Demand Resource Portfolio Plan filed on July 28, 2014 under Docket No. 2007-0341 for additional information on the programs.

Load Profiles

A very important assumption related to the demand and energy forecast is the profile of the demand over a given time period for example, a day, week, month, or year. Of interest to the modeler is the demand profile net of customer-owned generation, since the net profile is what must be met through the dispatch of resources available to the system.

For the PSIP runs, the load profile was modeled two ways: 1) the PSIP analyses were performed using an annual hourly load profile (that is, 8,760 data points for a year) was used to model the system, and 2) the PSIP sub-hourly analyses used 5-minute load profile data (that is, 105,120 data points for a year). The sub-hourly models were used to more accurately model intra-hour issues associated with ramping of generating resources and energy storage in response to variable renewable generation.

The net load profile of the system has changed dramatically over the past few years as a result of the proliferation of customer-sited distributed generation in the system. For the PSIP, a system gross load profile is assumed, and the profile of customer-sited distributed generation is subtracted out, resulting in the net load profile.

FUTURE RESOURCE ALTERNATIVES

Generation Alternatives

The following generating technologies were considered as resource options in the PSIP analyses. More detailed descriptions of each are found in Appendix F.:

- Simple-cycle combustion turbines
- Combined-cycle
- Internal combustion engines
- Geothermal
- On-shore wind
- Utility-scale solar PV
- Waste-to-energy
- Pumped-storage hydroelectric (see Appendix J)
- Biomass

Distributed Solar Generation (DG-PV)

The DG-PV forecast was determined outside of the resource optimization models, and therefore, the DG-PV forecast is a fixed input for purposes of the PSIP optimization models. Therefore, distributed generation was not treated as a resource “option” in the generation optimization models. If DG-PV is added as a resource option in the resource optimization models, DG-PV will never be selected it as an economical choice. In addition, utility-scale fixed-tilt solar will produce more energy per KW of installed solar PV capacity because the panel tilt and orientation of utility-scale solar can be more precise than can be achieved with distributed solar PV. This is reflected in the planning assumptions for solar PV where the utility-scale PV has a higher capacity factor than DG-PV.

During the study period, the amount of total installed DG on the Companies' systems is assumed to increase almost three-fold, from 328 MW (as of 7/15/2014) to just over 900 MW by 2030. The resulting installed DG capacity represents over 65% of the forecasted peak demands of the Companies in 2030, resulting in one of the most aggressive DG-PV programs in the world. Integrating this amount of DG-PV without affecting system reliability is a sizeable challenge that is addressed in Chapter 5. Figure 4-12 shows the forecast assumptions for DG-PV.

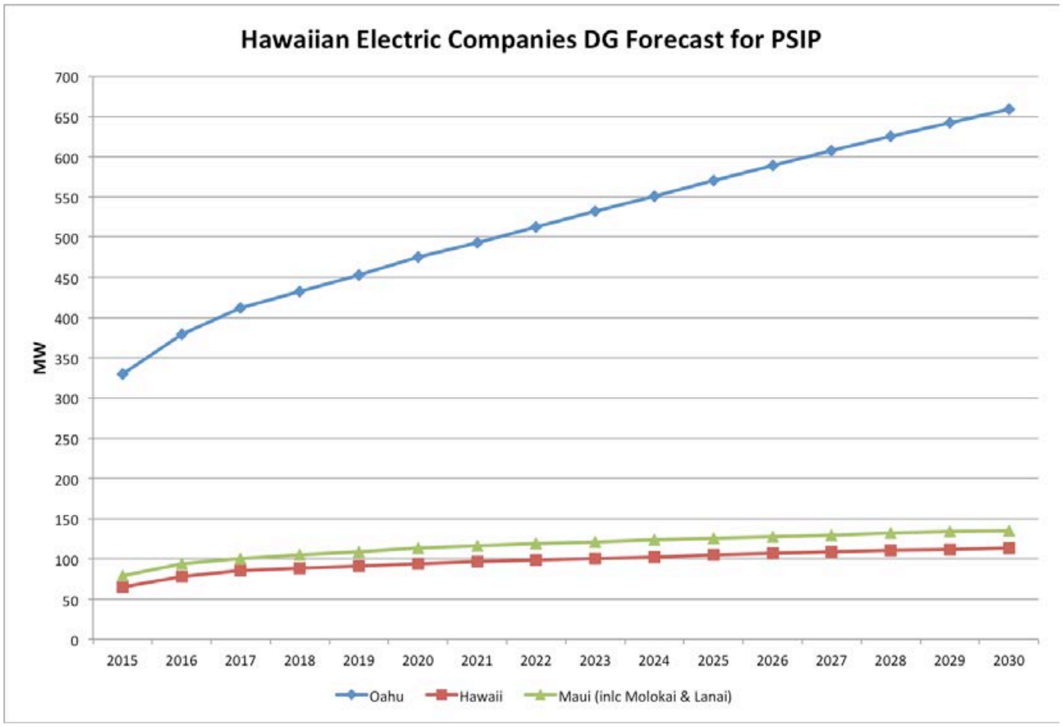

Figure 4-12. Installed DG Forecasts

Constraints on Generation Alternatives

The Companies made certain assumptions regarding the aggregate amounts of resource-types that can be installed across their service areas ("constraints"). The generation resource constraints were based on land availability, resource (for example, water availability, waste availability, etc.) limitations, available sites, commercial readiness and other factors that constrain the installation of certain resource types on specific islands. Siting constraints were not assumed for thermal generating resources and energy storage; rather it is assumed that those resources can be located on or near existing power plant and substation sites. The generating resource constraints by island are summarized in Table 4-2.

Constrained Resource Type	Resource Constraint by Island (Incremental to Existing and Committed)		
	O'ahu	Maui	Hawai'i
Geothermal	0 MW	25 MW	50 MW
On-Shore Wind	50 MW	> 500 MW	> 500 MW
Solar PV (Utility Scale)	360 MW	> 500 MW	> 500 MW
Waste-to-Energy	0 MW	10 MW	5 MW
Pumped Storage Hydro	50 MW	120 MW	90 MW
OTEC	100 MW	0 MW	0 MW
Biomass	30 MW	0 MW	34 MW
Ocean Wave / Tidal	0 MW	0 MW	0 MW

Table 4-2. PSIP Assumed Incremental New Resource Constraints by Island

New Generation Planning Assumptions vs. Future RFPs

The resource options and constraints discussed above are intended only for use as planning assumptions for the 2014 Power Supply Improvement Plans. The resource options and constraint assumptions set forth herein should not be interpreted as a policy position of the Hawaiian Electric Companies. The resource options and constraint assumptions set forth herein do not modify any of the Companies' policies and / or positions with respect to any ongoing or proposed PPA negotiation, pilot projects, or demonstration projects in which the Companies participate.

Third parties' responses to any future Request for Proposals by the Companies for the procurement of power supply resources and/or energy storage resources may include any resource option on any island, unless specifically excluded by the terms of the RFP, based on specific technical requirements. Any such proposals received by the Companies in response to a power supply and/or energy storage RFP will be evaluated on their merits. Such evaluation will include, at a minimum:

- Site control status.
- The commercial readiness of the technology proposed.
- Community acceptance of the project proposed.
- Confidence level regarding the ability to site, license, permit, and constructability the project proposed.
- Confidence level regarding the site-specific costs of the project proposed.
- Any other evaluation factors deemed relevant in an approved RFP document.

Cost and Operating Characteristics of New Generation Alternatives

The assumptions for capital cost for new generating resource options is based on the *Cost and Performance Data for Power Generation Technologies*, a report prepared for the National Renewable Energy Laboratory, by Black & Veatch, February 2012[15]. The Company intends to seek competitive bids for all new generating resources beyond the present committed additions. If the least cost resource proposals received indicate costs that are higher than what has been assumed in this PSIP, the capital costs associated with resource additions will be higher.

The detailed cost and operating characteristics of generation alternatives are included in Appendix F – Modeling Assumptions Data.

Acquisition Model for New Generating Resources

For purposes of the PSIP analyses, all new generating resources (beyond committed generating resources) are assumed to be owned by third parties. A surrogate for third party pricing was determined in two steps:

- The projected cash flow associated with the new generation resource (excluding fuel and variable O&M costs) were computed based on capital costs, operating costs, and utility revenue requirement profiles as if the utility owned the project.
- This cash flow was then levelized using the utility's cost of capital to obtain a levelized cost of the resource, which was assumed to be the PPA price.

Fuel costs and variable O&M were treated as pass-through costs for modeling purposes and will be included in bill impact calculations in the financial model.

This is a simplifying assumption for purposes of the PSIPs and is not intended to convey any preference or lack thereof for an acquisition model for future generating resources. At the time a resource acquisition is considered, the Companies will evaluate the appropriate business model for each new resource based on what is in the best interest of customers.

Energy Storage Alternatives

Utility-scale energy storage options are made available as a resource option in the PSIP production modeling. Appendix J: Energy Storage Plan contains a complete discussion of energy storage, including pricing and operating assumptions for energy storage. Energy storage is considered for providing ancillary services, to meet security constraints, and for load shifting.

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15 This report is available at http://bv.com/docs/reports-studies/nrel-cost-report.pdf.

The following storage durations were considered for energy storage to serve the indicated purpose:

- Regulating Reserves: 30 min
- Regulating Capacity: 30 min
- Contingency Reserves: 20 min
- Long-term Reserves: 3 hours
- Inertial, Fast Response Reserves: 0.05 min

Demand Response

The following demand response programs were considered in the PSIP analysis:

- Residential Direct Load Control (RDLC)
- Residential Flexible
- Commercial & Industrial Direct Load Control (CIDLC)
- Commercial & Industrial Flexible
- Water Pumping
- Customer Generation
- Time-of-Use (TOU) and Critical Peak Pricing (CPP)

The assumed impacts on capacity needs and energy requirements from these programs are detailed in Appendix F – Modeling Assumptions data.

FUEL PRICE FORECAST

The Companies anticipate continued consumption of liquid and gaseous fuels during the study period. However, the Preferred Plan incorporates a major shift away from imported liquid fuels (fuel oil, diesel, etc.) to biofuels and natural gas from LNG. In particular, the following fuels are available to the planning models during the planning period:

- Natural gas (from LNG)
- Biodiesel
- Lower sulfur fuel oil (LSFO)
- Black Pellet Biomass

The price forecast (in $/MMBtu) is included in Appendix F. Modeling Assumptions Data.

NON-TRANSMISSION ALTERNATIVES

Non-transmission alternatives (NTAs) were evaluated to determine whether using technologies and programs like distributed generation, energy storage and demand response could avoid transmission capital investments, and potentially reduce the cost of service to customers. An example of an NTA would be new generation located in specific areas to avoid the construction of transmission lines while allowing the Companies to meet adequacy of supply requirements (see Reliability Criteria assumptions discussion below.

Where applicable, NTA assumptions were made regarding their implementation in the Preferred Plan.

Hawaiian Electric

A transmission upgrade is anticipated in the Hawaiian Electric system during the study period. NTAs will be evaluated as part of the application to approve capital for this project

Hawai'i Electric Light

A single transmission upgrade is anticipated in the Hawaiian Electric system during the study period. NTAs will be evaluated as part of the application to approve capital for this project

Maui Electric

In the Maui Electric system, construction of new transmission lines and substations are being considered to address the following system issues:

- Under voltages, thermal overloads and voltage stability on the Central Maui 23 kV system due to the retirement of KPP.
- Under voltages and voltage stability in South Maui.
- Overloading of distribution substations.

These system issues can occur under normal and/or N-1 conditions[16]. Upgrades to the transmission system were purposed as solutions to help address the issues. Table 4-3 lists the issues, affected areas, and system upgrades that were proposed. Figure 4-13 provides a map of Maui identifying related substations and system network.

[16] A condition that happens when a planned or unplanned outage of a transmission facility occurs while all other transmission facilities are in service. Also known as an N–1 condition.

Issue	Area	System Upgrades
Under voltage, thermal overloads, and voltage stability	Central Maui	
23 kV System	23 kV Waiinu-Kanaha upgrade to 69 kV and re-conductoring of MPP–Waiinu and MPP–Pu'unene from 336AAC to 556AAC	
Under voltage and voltage stability	South Maui	Kamalii Substation and MPP Kamalii 69 kV transmission line
Overloading of distribution substations	Central and South Maui	Construction of Kuihelani (Central Maui) and Kaonoulu (South Maui) Substations

Table 4-3. Maui Electric System Issues and Transmission Solutions

The possibility of using the NTAs to fulfill the shortfall of capacity of 40 MW resulting from the Kahului Power Plant (KPP) decommissioning scheduled to begin in 2019 was also considered.

Definition of terms used in this report:

- "23 kV system"— 23 kV substations and feeders except Kula or Haleakala Substations and feeder to Hana Substations.
- "Central Maui"— Key substations include Kahului, Wailuku, and Kanaha.
- "South Maui"— Key substations include Kihei, Wailea, and Auwahi.

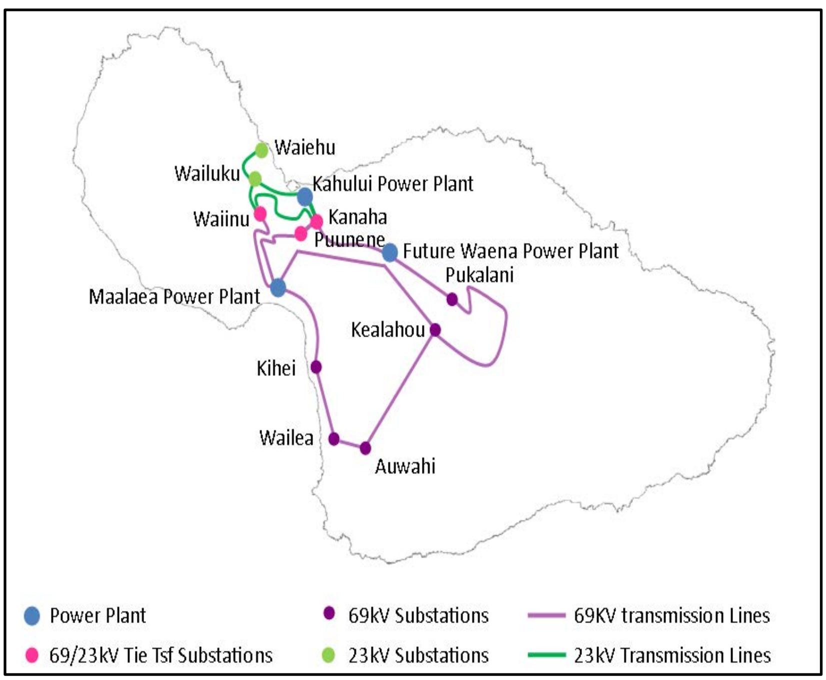

Figure 4-13. Transmission Overview for Key Maui Electric Substations Related to NTAs

NTA assumptions are listed below:

- NTAs are considered as possible alternatives to transmission system upgrades
- Combinations of NTAs are possible (requires more detailed studies)
- Transmission overload criteria
  - Normal conditions = normal ratings
  - N-1 contingency conditions = emergency ratings
- Voltage criteria
  - Over voltage violation: bus voltage greater than 1.05 per unit
  - Under voltage violation: bus voltage less than 0.9 per unit
- Kahului Power Plant units K1, K2, K3, and K4 will be decommissioned in 2019, resulting in a capacity shortfall of approximately 40 MW
- Pursuant to the Preferred Plan, Waena Power Plant will be online in 2019
- Ma‘alaea Power Plant units M4, M5, M6, M7, M8, and M9 will be decommissioned in 2022 resulting in a capacity shortfall of approximately 35 MW.

With the transfer capability limitations in Central and South Maui, the best solution should extend the transfer limits to allow the system to operate within a reasonable margin away from the limits. The bus voltages in the area will be used as a guideline to determine how much the load would need to be reduced for the buses to have a voltage around 0.95 per unit, which provides a reasonable margin above the planning criteria minimum of 0.90 per unit.

DR and DGPV were among alternatives examined to potentially eliminate the need for these transmission upgrades. They cannot, however, be considered reliable solutions. During an N-1 contingency, DR does not have the ability to respond quickly enough to prevent severe disturbances[17]. Additionally, DGPV provides little to no generation during system peak periods[18], and therefore cannot help reduce the loads to avoid under voltage and thermal overload violations during normal or N-1 contingency conditions.

Central Maui

With the retirement of KPP, the Central Maui load on the 23 kV system will need to solely rely on the generation from MPP. The system has three 69/23 kV transformers that interconnect the 23 kV system and the 69 kV system. These transformers are located at Waiinu, Kanaha, and Pu‘unene substations. During an N-1 contingency where one of

[17] With a large discrepancy between generation and load the frequency can decline immediately (0–3 seconds), where controls for DR have a response time of over 5 seconds.

[18] System peak occurs during the evening around 7:00 PM, when PV has minimal impact to the system.

these feeders[19] becomes unavailable, under voltages and thermal overloads occur on the remaining transformers. If there is too much power being transferred to the 23 kV system from the 69 kV system, the system may not be able to manage the transfer and can experience a voltage collapse or island wide blackout. Therefore, the upgrade of the 23 kV Waiinu–Kanaha line to 69 kV and the reconductoring of MPP–Waiinu and MPP–Pu‘unene are proposed to shift some of the loads from the 23 kV system onto the 69 kV system.

The *Kahului Power Plant Retirement-Comprehensive Assessment* (included in the Maui Electric PSIP) provides analysis to locally reduce the amount of load and help with the voltage issues on the 23 kV system. The following NTAs were considered: distributed generation (DG), battery energy storage system (BESS), and synchronous condensers from decommissioned KPP units. The DG and BESS NTAs could provide the system with generation to meet the adequacy of supply; however, acres of property would be required to accommodate the large amount of DG or BESS. Installing these NTAs would be difficult due to the size of available property and need for zoning and air quality permits in Central Maui. Converting the KPP units to synchronous condensers or installing DG or BESS at the KPP location were determined to be unfeasible because, KPP is located in a tsunami inundation zone[20]. Upgrading the transmission system in Central Maui is the most feasible option given in Central Maui the lack of available real-estate, existing residential communities, and the tsunami inundation zones.

South Maui

In South Maui, the loads from Kihei and Wailea are mainly served through the MPP–Kihei 69 kV transmission line. If there is an outage of the MPP–Kihei line, the South Maui load will need to be served from the MPP–Kealahou 69 kV line, which increases the electrical distance serving loads. The longer distance would result in major losses[21] and possibility of a voltage collapse. The distance would increase to approximately 23 miles, as shown in Figure 4-14.

[19] MPP–Waiinu or MPP–Pu‘unene.

[20] Maui Electric’s preference is to avoid Tsunami inundation zones as locations for new generation, where feasible.

[21] Due to higher impedance and an increased voltage drop from the source to the load.

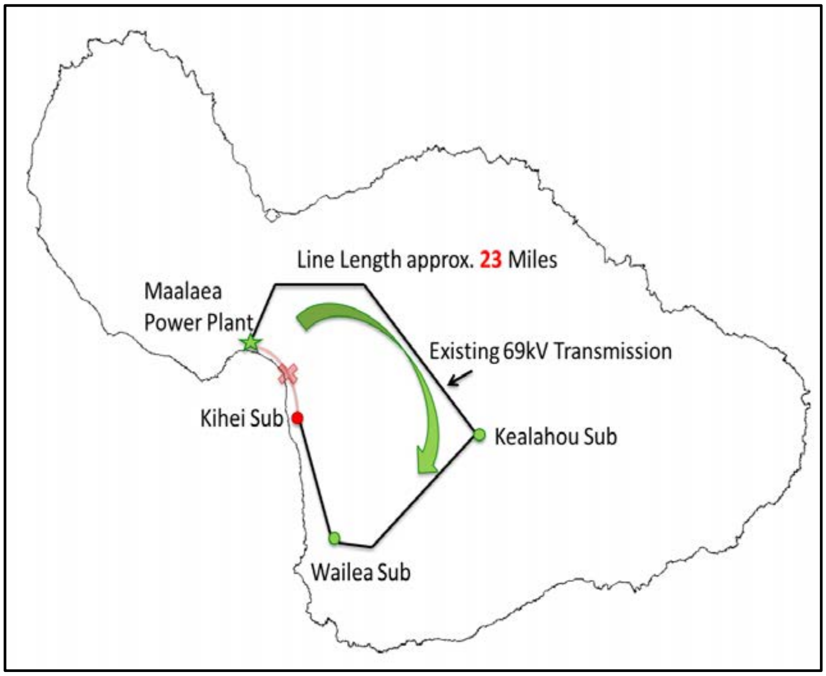

Figure 4-14. Longer Distance Required to Serve Loads in Kihei Under an N-1 Contingency

The *Ma'alaea-Kamalii Transmission Line Alternatives* report (included in the Maui Electric PSIP) analyzed various NTAs to defer the construction of new transmission infrastructure. For voltages to remain within a reasonable margin above 0.90 per unit, the total load in South Maui would need to be reduced by at least 20 MW. Several of the NTAs considered increased the voltages in South Maui, but did not effectively reduce both the load issue and possibility of a voltage collapse.[22] For example, the synchronous condensers and static capacitors can increase the voltages but these transmission system facilities do not generate MW to serve the load.

The hybrid of a BESS and DG is considered to be the optimal plan. A hybrid combination of a BESS and DG would shorten the duration of the BESS needed (reducing costs) and allow the DG to only be started in the case of a contingency, as opposed to being run whenever the system load is above 150 MW (lowering fuel consumption). Maui Electric plans to pursue this option based on the following:

All plans in the Maui Electric PSIP include a BESS for Contingency Reserve in compliance with EPS System Security Study.

The Contingency Reserve BESS (20 MW:30 Min) is assumed to be located in South Maui so that when a transmission event occurs in South Maui, the BESS will be able to operate

[22] An under-voltage load shed (UVLS) scheme is currently imposed at Kihei and Wailea substations during system loads greater than 150 MW, in order to avoid a voltage collapse. With load curtailment, customers remain offline until the system returns to normal conditions, or the system load decreases below 150 MW. The UVLS scheme is not a viable long-term solution.

for 30minutes. Within that time, the 24 MW of Internal Combustion Engine (ICE) generation, located in South Maui, will be able to start in order to support South Maui transmission system.

If the Contingency Reserve BESS is not located in South Maui, then the 24 MW of ICE generation in South Maui will have to operate daily when the system load is 150 MW or greater to support the South Maui system in case a transmission event occurs.

Maui Electric Distribution Transformer Overloads

Our forecasts indicate that several distribution transformers will be overloaded in Central and South Maui in the near future. This prompted the need for a new distribution substations[23] to be built to help alleviate the loads on the existing distribution transformers. DG and BESS were considered as alternatives to building a new distribution substation that could potentially lessen the load on existing substations where the overloading occurs, contribute toward firm capacity, and help alleviate the need for additional transmission lines in the area. Preliminary assessments found these options to be unfavorable due to permitting, physical, and/or financial constraints.

RELIABILITY CRITERIA

The Hawaiʻi Reliability Standards Working Group (RSWG) Glossary of Terms[24] defines "Reliability" as follows:

> ***Reliability.*** An electricity service level or the degree of performance of the bulk power ("utility" in Hawaiʻi) system defined by accepted standards and other public criteria. There are two basic, functional components of reliability: operating reliability and adequacy.

The RSWG Glossary of Terms goes on to define "adequacy" and "operating reliability" and as follows:

> ***Adequacy.*** The ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.
>
> ***Operating reliability.*** The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components.

The North American Electric Reliability Corporation (NERC) formally replaced the term "security" with the term "operating reliability" after September 2011, when the term

[23] Kuihelani in central and Kaonoulu and Kamaliʻi in South Maui.

[24] RSWG Glossary of Terms. Docket No. 2011-0206.

"security" became synonymous with homeland protection in general, and critical infrastructure protection in particular[25].

The Hawaiian Electric Companies have continued to use the term "system security" with the exact same meaning as "operating reliability". "System security" is therefore the term used herein.

Adequacy of Supply

One of the most commonly used planning metrics for designing a system to meet the adequacy of supply requirements is "reserve margin". For purposes of the PSIPs the production modeling teams assumed a minimum 30% planning reserve margin for generation. As the systems evolve, the target reserve margin will be periodically evaluated to ensure resource adequacy and supply, with consideration of the resource risk based historical performance of the types of resources providing the capacity.

System Security

The derivation of system security requirements for the PSIP analyses is explained in detail in the following section.

SYSTEM SECURITY REQUIREMENTS

Electric power grids operate in a manner that provides reliable and secure power during both normal conditions and through reasonably anticipated events. To achieve this reliable and secure operation, the grids operate under system security constraints. These constraints include requiring certain resources to be utilized and require the power system to be operated in certain ways.

In traditional power systems[26], conventional thermal generating units provide most of the electric energy and meet most of the security constraints by supplying system inertia, frequency response, and other ancillary services as part of their inherent operating characteristics and governor controls. As new types of generation, such as wind and solar PV, became significant providers of energy and displaced conventional thermal generation, the requirements to ensure there is a sufficient supply of grid services for

[25] Source: http://www.nerc.com/docs/pc/Definition-of-ALR-approved-at-Dec-07-OC-PC-mtgs.pdf.

[26] In this context, a "traditional power system" or a bulk power system (BPS) is a large interconnected electrical system made up of generation and transmission facilities and their control systems. A BPS does not include facilities used in the local distribution of electric energy. If a bulk power system is disrupted, the effects are felt in more than one location. In the United States, the North American Electric Reliability Corporation (NERC) oversees bulk power systems.

security and reliability becomes more important. Due to their inherent characteristics, variable generation resources often cannot supply these services, requiring other standalone services to be provided to the grid or special design modifications be made to the variable generators. Further, the variable output from these resources can increase the need for grid services.

The majority of variable energy resources are connected to the power system through an inverter. The inverter isolates a variable energy resource from the grid and converts the energy produced into alternating current (AC) power that is then supplied to the electric grid. The inverter allows the power system and the variable energy resources to operate at different voltages and frequencies, optimizing the performance of the variable energy resource in its conversion of source energy (wind and sun for example) to electric energy. Variable energy resources typically do not have the capability to store their energy and do not typically utilize a governor type control, which would automatically adjust energy in response to system balance (frequency). Instead, unless incorporating advanced control systems, they produce the energy that is available from their resource (for example, solar or wind) regardless of system conditions. If the power system suddenly requires more energy, variable energy resources cannot increase their output beyond the available resource energy (unless it was previously curtailed to less than the available resource energy). Because of this reliance on available energy, variable energy resources can typically supply downward regulation—decreasing their power output—but have limited ability to supply upward regulation—increasing their output.

Some variable energy resources (such as wind turbines) may be able supply inertia or fast frequency response through advanced inverter controls. Like conventional generators, this inertia does act to help slow the rate of frequency decline, and can be a faster response—but unlike conventional plants, this response is not sustained and is eventually withdrawn. Variable energy generation does not have the ability to replace the short-duration inertia energy with energy through governor response.

For the Companies' island grids, several ancillary services are required to reliably operate the power system: regulating reserve, contingency reserve, 10-minute reserve, 30-minute reserve, long lead-time reserve, black start resource, primary frequency response, fast frequency response[27], and secondary frequency control. (These services are more fully explained in Appendix E: Essential Grid Services.)

Establishing regulating reserve, contingency reserve, primary frequency response, and fast frequency response are defined by characteristics of the system requirements to maintain target reliability and planning standards. Technical studies have defined these

[27] Fast frequency response is a subcategory of the 10-minute reserve ancillary service.

security requirements; the choice as to how to meet the requirements is often an economic decision based on generation and resource planning studies.

Although the size and resource mix of the Companies' electrical systems have a large degree of variation, the proliferation of variable generation on each of the islands results in similar constraints and challenges among them.

The security requirements for each island can be defined by the requirements for regulating reserve, contingency reserve, voltage support, and fast frequency response. Other constraints (such as ramp rates, 10-minute reserve, and 30-minute reserve) are required but are not the limiting conditions for the power system security.

Regulating Reserve

Regulating reserve is the amount of capacity that is available to respond to changes in variable generation or system load demand to maintain system operation at a target frequency (maintaining close to 60 Hz). Regulating reserve is required for both upward regulation (additional generation or decreased load through demand response) and downward regulation (less generation or increased load through demand response). These responses are required to maintain the balance between total system load demand and supply.

Regulating reserve provides for the normal fluctuation of system load plus the changes in variable generation. Normal fluctuations of system load demand in the Companies' systems are relatively slow and very predictable from day to day. Variable generation—wind generation, distributed solar generation, and utility-scale solar generation—can have extreme variations and dwarf the regulation requirements of normal load demand changes.

Wind Generation

The regulation requirements for wind generation were determined by plotting a years' worth of 2-second data from the SCADA systems for the wind generation facilities on each of the islands. By using 2-second SCADA data from all wind resources, time skew error between the sites is minimized and the actual frequency impact from the changes in total amount of wind is identified.

The amount of regulation capacity that is required is determined by the magnitude of change in wind generation over a given period of time. In wind systems, regulation requirements increase with increasing time intervals. The time interval is largely dictated by the amount of 10-minute reserve available. The 10-minute reserve is critical to the system operator to replace regulating or contingency reserve as they are used by the system. When a wind ramp begins to occur, the system operator cannot predict in real time the duration or magnitude of the ramp event, consequently there is some time in each ramp event where the operator is evaluating the ramp and estimating the severity of the ramp. That time period is assumed to be within the first 10 minutes (or less) of the ramp event. After assessing the ramp event will require mitigation, the operator would typically call upon a reserve resource that will be online within 10 minutes or less (a 10 minute reserve resource). Considering the time for evaluating the event and bringing reserves online, the mitigating resources could be online 20 minutes after the ramp condition started. Therefore, a 20-minute ramp condition is used as the basis to determine the regulation capacity.

The plots in Figure 4-15 through Figure 4-17 depict the variability of wind resources in a typical month on each of the islands.

Hawaiian Electric Wind Generation: The regulating reserve is carried on a 1:1 basis until the actual wind generation exceeds 50% of the nameplate capacity. No additional regulating reserve is necessary for generation levels in excess of 50% of nameplate capacity. The regulation criterion was based on the 20-minute wind ramp events between July 1, 2013 and June 30, 2014 of the Kawailoa Makai, Kawailoa Mauka, and Kuhuku wind generation facilities.

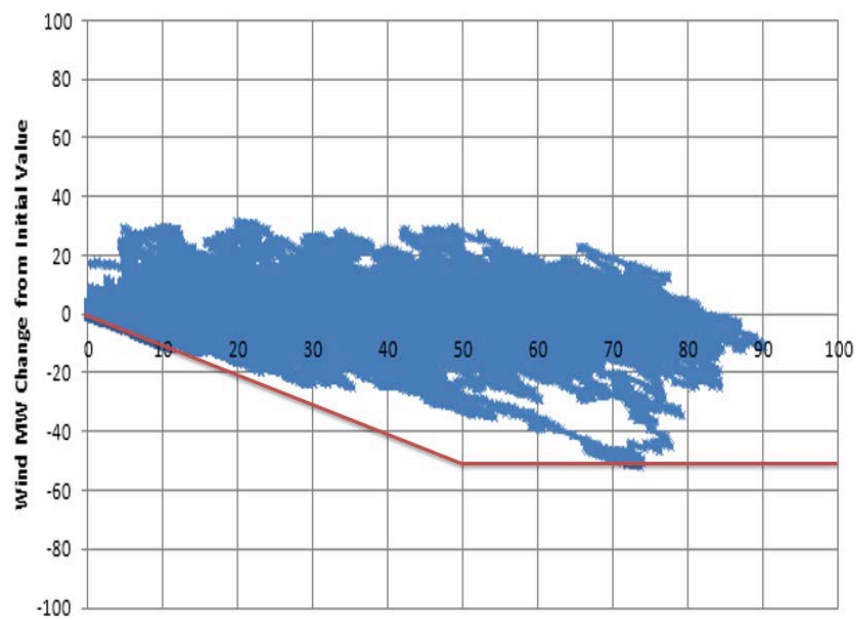

Figure 4-15. 20-Minute Scatter Plot for Hawaiian Electric Wind Generation

Each point in the scatter-plot shown in Figure 4-15 represents one two-second scan from the wind power data. The y-axis shows the total change in wind power between the initial power and 20 minutes after the initial power point. The x-axis shows the initial power output of the wind generation facilities. Interpreting the data for a point (20,–10), the initial total wind power output was 20 MW; twenty minutes later, the wind power output was 10 MW. Therefore, there was a net loss of 10 MW of wind power over those 20 minutes.

The red line represents the recommended regulation capacity. The regulation capacity will not be sufficient for all possible wind ramps, but will be sufficient for the vast majority of wind ramp events.

Hawai'i Electric Light Wind Generation: The wind ramps on the Hawai'i Electric Light system require a similar level of regulating reserve as the Hawaiian Electric system, despite the wind generation facilities having a higher capacity factor. Figure 4-16 shows the wind variability on the Hawai'i Electric Light system for the first half of May 2014 for the Hawai'i Renewable Development (HRD) and Tawhiri wind generation facilities.

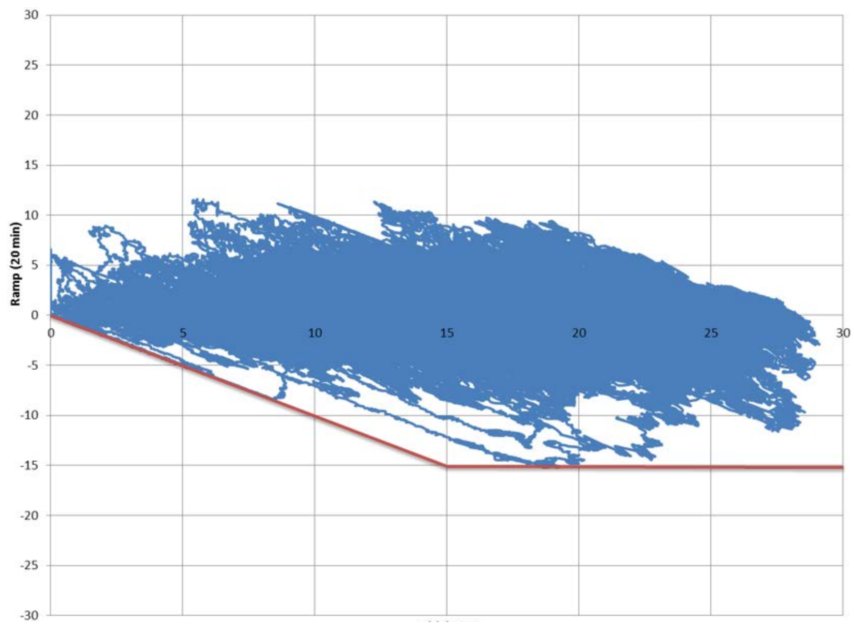

Figure 4-16. 20-Minute Scatter Plot for Hawai'i Electric Light Wind Generation

Maui Electric Wind Generation: The wind ramps on the Maui Electric system require less regulating reserve compared to those for the Hawai'i Electric Light and Hawaiian Electric power systems. The battery energy storage systems (BESS) associated with the wind generation facilities mask some of the more severe ramp rates. Figure 4-17 shows the wind variability on the Maui Electric system for the first half of December 2013 for the Kaheawa One, Kaheawa Two, and Auwahi wind generation facilities.

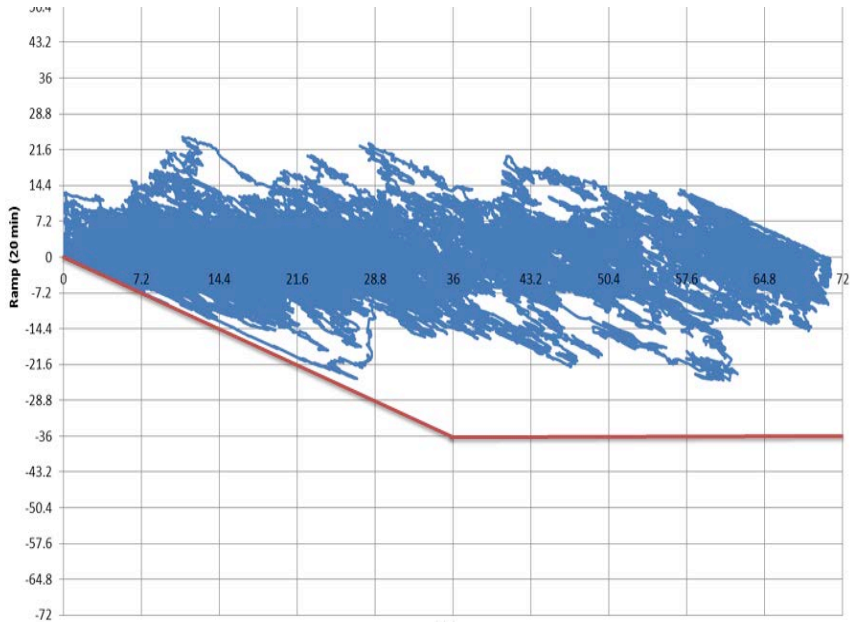

Figure 4-17. 20-Minute Scatter Plot for Maui Electric Wind Generation

Maui Electric is assumed to have a similar requirement to Hawai'i Electric Light if the BESS were used for optimized system requirements as opposed to simply providing ramp rate control of an individual wind generation facility.

Distributed Solar

Distributed solar (referred to as DG-PV in this report) for the power system on Maui island for 2007 and 2008 estimated island-wide distributed solar generation with a 2-second sample rate. The data assumed an installed DG-PV capacity of 15 MW. The raw data was scaled to estimate the DG-PV generation with 30 MW installed DG-PV capacity. The PV data was analyzed to determine the change in DG-PV generation over a 20-minute time frame for the months from January to July. The results are shown in Figure 4-18, which shows the 20-minute distributed solar generation ramp rate data for the Maui island electric system with 30 MW capacity

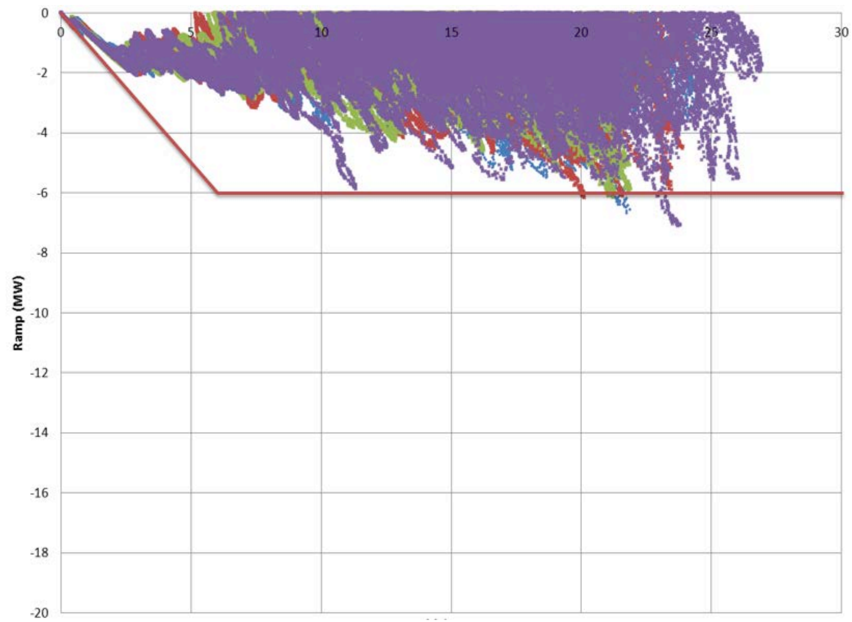

Figure 4-18. Maui Electric 20-Minute Solar Ramps

The x-axis represents the initial solar generation level of 20 MW. The y-axis shows the solar generation change 20 minutes later. Interpreting the data for a point (20,–10), the initial solar generation level was 25 MW; 20 minutes later, the total solar generation level was 15 MW. So the change in solar generation was –10 MW.

The two piece red line shows the recommended solar regulation capacity characteristic: that is, the system operator maintains a regulating reserve with a 1:1 ratio for solar generation levels up to 20% of the solar nameplate capacity and no additional reserve for solar generation levels between 20% to 100%.

Figure 4-19 shows the same regulating reserve criterion applied to the Hawai‘i Electric Light DG-PV. The Hawai‘i Electric Light data was derived from actual solar recordings at approximately 45 locations on the Hawai‘i Electric Light power system. These recordings were scaled based on the distributed solar generation installed near the recording location. The total generation was scaled to represent a system having 100 MW of DG-PV (nameplate capacity).

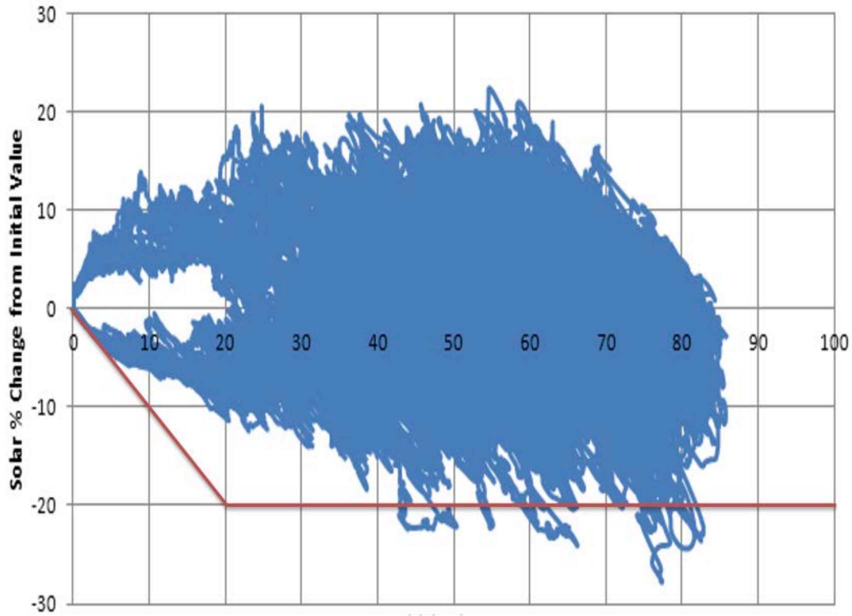

Figure 4-19. Hawai'i Electric Light 20-Minute Solar Ramps for Half of February

Using a 1:1 generation level to regulating reserve capacity ratio, both the Maui Electric and Hawai'i Electric Light data sets produce similar results.

Hawaiian Electric Utility-Scale Solar

There are currently only two utility-scale solar facilities (referred to as PV in this report) on the Hawaiian Electric power system on O'ahu. Results indicate that over both 30-second and 20-minute time periods, the output of each individual PV facility can vary from 100% to 0%. The estimated, combined effect of the two plants together results in considerable improvement as shown in the 20-minute scatter plots totaling 100 MW of PV capacity in Figure 4-20.

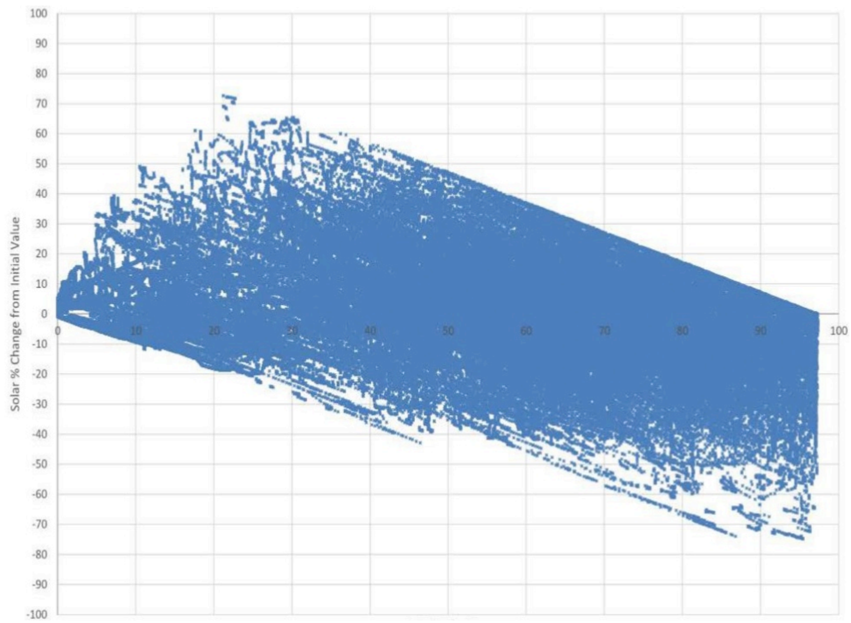

Figure 4-20. Hawaiian Electric Combined Station Class PV

Based on these plots, the required regulation of the two combined wind generation facilities drops from a ratio of 1 MW regulation:1 MW of PV to a ratio of 0.5–0.6:1. The installation of additional PV facilities over a wider area may allow this number to decrease further. Accordingly, the ratio is estimated to decrease to 0.3:1 by 2017 with the addition of more utility-scale solar facilities.

Two-second SCADA data shows that the ramps between wind, DG-PV, and PV do not have 100% correlation. Although there are periods where the ramps cancel each other out, these appear to be random events and not systematic occurrences. Many events are observed when the ramps overlap each other for a portion of the event. Consequently, all regulation requirements are assumed to be additive.

Regulating reserve is a security constraint. The choice of resource used for the reserve, however, is often determined by economics. Regulation can be supplied by resources immediately responsive to Automatic Generation Control (AGC) and meeting the time frames and accuracy of the response. This can include firm dispatchable generation which may be conventional or renewable, variable generation (which requires partial curtailment for upward reserves), energy storage, and/or demand response.

Some of the resources that can provide regulating reserve can also contribute to contingency reserve. These are the resources that respond to system events without requiring a control signal from AGC, through inertial and governor response (such as thermal generating units). Since allocation of regulating reserves considers economics and therefore may not result in use of resources that can contribute to contingency reserves, additional regulating reserve is not assumed to contribute to contingency reserve. The use of additional thermal generating units to provide regulating reserve would satisfy the contingency reserves requirement. The regulating reserve, however, may be supplied by resources with different characteristics than thermal generation, therefore increasing the amount of required contingency reserve.

Contingency Reserve

In planning and operating the power system, care must be taken to ensure that, under any circumstances, the system remains operable following the largest single potential loss of energy. This largest possible loss might be due to a trip of a particular generating plant or the loss of critical interconnection equipment. This requirement is known as the single largest contingency criteria and is included as a requirement within TPL-001.[28] The system is able to withstand the loss of the largest single contingency through the implementation of contingency reserve.

Contingency reserve can be provided through resources that respond immediately and automatically to system imbalances. This can include resources such as conventional generation with governor's response, energy storage, or through "fast-acting" demand response. In isolated power systems (such as those on islands), the response requirement of contingency reserve is extremely fast. As the power system evolves and displaces thermal generation with increasing amounts of variable generation, the required response time of the contingency reserve becomes even faster due to the reduced available inertia and frequency response. This very fast response time precludes many types of energy systems from providing effective contingency reserve. Even traditional contingency reserve carried on conventional generation will not be fast enough to provide acceptable contingency response with the reduction in inertia and frequency response resulting from the change in resource mix.

TPL-001 establishes the allowable system performance criteria for the loss of the largest single contingency. The criteria allow a certain amount of the contingency reserve to be

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[28] See Appendix M: Planning Standards for the details of TPL-001 as well as details on BAL-052: Planning Resource Adequacy Analysis, Assessment and Documentation Standard. Together, these two standards form the basis for performing system studies.

provided by automatic under frequency load shedding (UFLS) for each system. These amounts currently vary from 12% of the system's customers for Hawaiian Electric to 15% for Hawai'i Electric Light and Maui Electric.

As system inertia continues to decline (for example as the thermal generation is displaced by increasing amounts of variable generation), providing contingency reserve capable of responding fast enough to meet the criteria in TPL-001 becomes more difficult. For instance, the contingency reserve implemented as part of the UFLS system must be fully deployed within 7 cycles (0.12 seconds) of reaching the target frequency. Deployment of effective contingency reserve through governor action of thermal generation also becomes more difficult as the rate of change of frequency decline increases. Many of the contingency reserves that have historically been utilized on the power systems in the Hawaiian Islands are now simply too slow to respond to the new system characteristics.

For instance, the April 2, 2013 loss of the sudden trip of the AES Hawai'i facility totaling 200 MW (that is, 180 MW of net generation to the grid plus 20 MW of ancillary load) occurred at a time when the system had over 400 MW of contingency reserve available as unloaded generation. However, the system frequency declined so fast, that few of the reserves were able to be deployed by the thermal unit governors before experiencing three stages of load shedding (Figure 4-21).

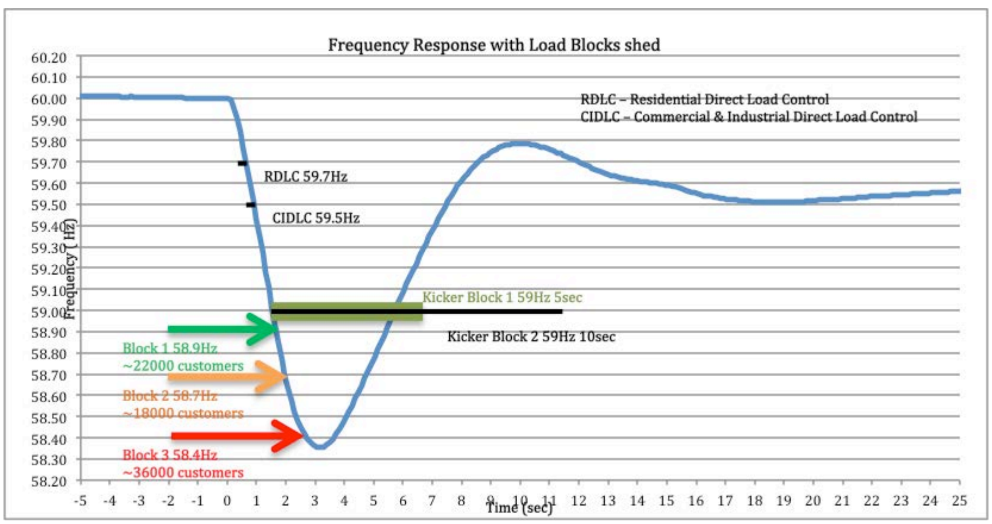

Figure 4-21. Frequency Response with Load Blocks Shed

As the system continues to displace conventional generation from online operation, reliability decreases and security risks increase for contingencies unless mitigated by fast acting contingency reserve. The amount of fast acting contingency reserve required for each system in order to meet the criteria defined by TPL-001 has been studied as part of the PSIP analytics.

For each of the systems, transient stability simulations were used to evaluate the response of the system to the loss of the largest contingency for various operating conditions for the planning years 2015–2030. The simulations were developed to model the boundary conditions for the system, ensuring the criteria developed provide satisfactory security performance for the most severe conditions experienced under actual expected system operations.

The conditions for each of the planning years were determined based on the forecast amount of variable generation added to the system, retirement of existing units, and/or the addition of new generating units. Not all years were studied. If there were no significant deviations from year to year, the results from the years on either end of the quiescent period were assumed applicable to the years not studied.

For each year selected, a unit commitment schedule was developed that resulted in the minimum number of conventional units being operated and the maximum use of variable generation. The largest contingency, whether it resulted from the use of conventional generation or variable generation, was tripped offline at full load. The results were analyzed and "fast-acting" energy storage was added until acceptable performance was achieved. This process was repeated for all selected years.

For systems with high availability of wind, new wind resources were compared to energy storage systems to determine if curtailed wind resources could provide the desired characteristics of energy storage systems.

The results for all of the islands are very similar. In the near term, it is difficult or infeasible to meet the planning criteria for existing conditions. With existing DG-PV characteristics, each system collapses (that is, island-wide blackout) for a number of different conditions. All three systems could also experience a system collapse for transmission faults unless cleared in less than 9–11 cycles. The Hawaiian Electric system is vulnerable to collapse following the loss of the largest single contingency.

In the immediate future, the retrofits of control features to DG-PV installations are essential to mitigating the chance of system collapse for these events. The DG-PV must be retrofitted to the ride-through standards in the proposed changes to Rule 14H. It is assumed that most of the DG-PV can be retrofitted with only a small amount on each legacy system that cannot be retrofitted.

Another immediate improvement is to decrease the time required to reliably detect and clear faults on the systems' transmission lines. Historically, a fault could be present on the system for 18–21 cycles (0.30–0.35 seconds) in almost all systems. Today, for faults that exist longer than 9–11 cycles (0.15–0.18 seconds), the faults can result in a total system collapse. This time is referred to as the "critical clearing time" for the respective power system. Critical clearing times less than 18 cycles require the use of communications assisted relaying on all transmission terminals.

As the amount of variable generation increases, the critical clearing time will continue to decrease and the rate of frequency collapse will continue to increase. It was therefore assumed that retrofitting of the DG-PV would be completed prior to 2015, and the installation of improved relay and communications systems would be completed prior to 2016. It was assumed that the first year any new variable energy resources could be added to any system is 2017.

To mitigate the number of customers impacted by such contingencies and improve system security, the UFLS should be upgraded to recognize a system contingency and its characteristics. For instance, as the amount of DG-PV continues to increase, the amount of load controlled by each stage and the effectiveness of the UFLS will correspondingly degrade. In order to prevent frequency excursions into the regions that place the entire system at risk of collapse, more feeder breakers need to be activated at Stage 1 of the UFLS. This would result in the loss of more customers for Stage 1 events than historically experienced. However, in the evening when the DG-PV and PV is not producing, the operation of these additional breakers in Stage 1 would result in shedding more load than is necessary, producing an over frequency condition that could also place the system at a high risk. The load shedding system needs to be adaptive and dynamic. It needs to be able to activate the correct amount of breakers to cover the contingency and minimize the number of customers whose service is interrupted. An adaptive load shedding system is assumed to be operational at all three major utilities prior to 2016.

Hawaiian Electric: Years 2015–2016

The amount of DG-PV that cannot be retrofitted to the meet the proposed ride-through settings is critical for the security of the power system. The existing amount of DG-PV tripping for original standard IEEE 1547 trip settings on the Hawaiian Electric system is estimated to be 70 MW. With 70 MW of legacy DG-PV, the system cannot survive the largest contingency. As the legacy DG-PV is reduced, the system response improves. The maximum amount of legacy DG-PV is recommended to be no more than 40 MW. This level of legacy DG-PV still results in significant load shedding and violations of TPL-001, however, the power system would be more resistant to collapse.

Legacy DG-PV also impacts the over frequency performance of the power system, since the legacy DG-PV currently trips offline at 60.5 Hz. The loss of 250+ MW of legacy DG-PV results in the collapse of the Hawaiian Electric system. The reduction in the amount of legacy DG-PV that trips at 60.5 Hz is also recommended to be reduced to less than 40 MW.

In 2015, aside from modification of DG-PV settings to provide ride-through, options are limited to only changes in system operations, protective relaying, and communications improvements. A transfer trip scheme between AES, Kahe 5, Kahe 6, and the UFLS breakers can help prevent, in some instances, one stage of load shedding for the loss of one of the larger units. Reducing the maximum output of AES is the only other mitigation strategy that was identified as feasible for 2015.

By the end of 2016, approximately 286 MW of utility-scale PV is expected to be installed on the power system. While this PV forces other generation offline and further decreasing the system inertia, it also has the potential to supply fast-acting contingency reserve through curtailed energy. Without curtailment and additional contingency reserve, the displacement of the thermal unit by the station PV cannot be mitigated. The additional contingency reserve could be supplied by energy storage.

In 2017, the system requires 200 MW of contingency reserve to meet the requirements of TPL-001. It should be noted that due to the extremely fast frequency decay associated with the sudden trip of a large generator, the contingency reserve must be provided by systems other than thermal generation (such as fast acting storage or other similarly fast responding device). Following the installation of the contingency reserve, the system can operate with few system constraints providing faults meet the critical clearing time. Although simulations to assess the system stability with as few as two firm (and dispatchable) units were completed, this was done only to assess the stability of the system during a boundary condition. System operating considerations would preclude operation with fewer than three dispatchable units.

Following the installation of 200 MW of contingency reserve in 2017 (for example, energy storage), additional contingency reserve may be required if additional variable generation is added and the single largest contingency remains at 180 MW (that is, AES).

The system security constraints are summarized in Table 4-4 through Table 4-7 for Hawaiian Electric. The Thermal Units Required column specifies the minimum number of thermal units required for stability. The remaining columns designate the specific constraint.

Value	Capacity (MW)	Thermal Units Required	Ramp Rate Required	Regulating Reserve: Day Time	Regulating Reserve: Night Time	Contingency Reserve	30-Minute Reserve	Voltage Support (SVC)
2017 200 MW AES Trip								
Station PV	272	4	86.6 MW/min	281 MW (20% of DG-PV + 35% Station PV + 50% Wind)	62 MW (50% Wind)	200 MW	200 MW	±80 MVAr
DG-PV	471							
Wind	123							
Largest Unit	200							
2017 100 MW AES Trip								
Station PV	272	4	86.6 MW/min	281 MW (20% of DG-PV + 35% Station PV + 50% Wind)	62 MW (50% Wind)	100 MW	100 MW	±80 MVAr
DG-PV	471							
Wind	123							
Largest Unit	200							

Table 4-4. Hawaiian Electric 2017 System Security Constraints

Value	Capacity (MW)	Thermal Units Required	Ramp Rate Required	Regulating Reserve: Day Time	Regulating Reserve: Night Time	Contingency Reserve	30-Minute Reserve	Voltage Support (SVC)
2022 AES + LM6000 Units								
Station PV	272	3: AES + 2 LM6000	95.1 MW/min	311 MW (20% of DG-PV + 35% Station PV + 50% Wind)	62 MW (50% Wind)	100 MW	100 MW	±80 MVAr
DG-PV	556							
Wind	123							
Largest Unit	100							
2022 AES + LMS100 Units								
Station PV	272	2: AES + 1 LMS100	95.1 MW/min	311 MW (20% of DG-PV + 35% Station PV + 50% Wind)	62 MW (50% Wind)	100 MW	100 MW	±80 MVAr
DG-PV	556							
Wind	123							
Largest Unit	100							

Table 4-5. Hawaiian Electric 2022 System Security Constraints

Value	Capacity (MW)	Thermal Units Required	Ramp Rate Required	Regulating Reserve: Day Time	Regulating Reserve: Night Time	Contingency Reserve	30-Minute Reserve	Voltage Support (SVC)
2030 LM6000 Units								
Station PV	272	7	95.1 MW/min	337 MW (20% of DG-PV + 35% Station PV + 50% Wind)	62 MW (50% Wind)	60 MW	100 MW	±80 MVAr
DG-PV	631							
Wind	123							
Largest Unit	100							
2030 LMS100 Units								
Station PV	272	5	95.1 MW/min	337 MW (20% of DG-PV + 35% Station PV + 50% Wind)	62 MW (50% Wind)	60 MW	100 MW	±80 MVAr
DG-PV	631							
Wind	123							
Largest Unit	100							

Table 4-6. Hawaiian Electric 2030 System Security Constraints

Value	Capacity (MW)	Thermal Units Required	Ramp Rate Required	Regulating Reserve: Day Time	Regulating Reserve: Night Time	Contingency Reserve	30-Minute Reserve	Voltage Support (SVC)
2030 Minimum LM6000 Units; 60 MW BESS								
Station PV	272	3	95.1 MW/min	337 MW (20% of DG-PV + 35% Station PV + 50% Wind)	62 MW (50% Wind)	100 MW	100 MW	±80 MVAr
DG-PV	631							
Wind	123							
Largest Unit	100							
2030 Minimum LMS100 Units; 60 MW BESS								
Station PV	272	2	95.1 MW/min	337 MW (20% of DG-PV + 35% Station PV + 50% Wind)	62 MW (50% Wind)	100 MW	100 MW	±80 MVAr
DG-PV	631							
Wind	123							
Largest Unit	100							

Table 4-7. Hawaiian Electric 2030 System Security Constraints with 60 MW BESS

Hawai‘i Electric Light: Years 2015–2016

The Hawai‘i Electric Light system was one of the first island systems to revise the tripping points of the DG-PV systems from 59.3 Hz to 57.0 Hz. Consequently, they have a smaller percentage of DG-PV that trips at 59.3 Hz on the power system as compared to the other islands. However, all of the DG-PV has over frequency trip points of 60.5 Hz. Due to this condition, fault durations longer than 9 cycles result in the potential for system collapse in simulations.

Simulations for years 2015–2016 assumed improvements to protective relaying and communications were in service. Direct transfer tripping of system load following the loss of the largest contingency is recommended to mitigate the number of customers impacted by single contingency events.

Hawai'i Electric Light: Years 2017–2030

The security of the Hawai'i Electric Light system requires the addition of contingency reserve and additional regulating reserve in 2017 as the level of DG-PV increases. The regulating reserve can be supplied by either thermal units, energy storage units, curtailed wind, curtailed solar, or controlled load.

Although simulations to assess the system stability with as few as two firm (and dispatchable) units were completed, this only assessed the stability of the system during a boundary condition. System operating considerations would preclude operation with fewer than three firm (and dispatchable) facilities under automatic generation control. The assessment assumed typical dispatchable PGV, Hu Honua, and Keahole Combined Cycle (single train).

The system security constraints are summarized in Table 4-8 through Table 4-10 for Hawai'i Electric Light. The Thermal Units Required column specifies the minimum number of thermal units required for stability. The remaining columns designate the specific constraint.

Value	Capacity (MW)	Thermal Units Required	Ramp Rate Required	Regulating Reserve: Day Time	Regulating Reserve: Night Time	Contingency Reserve	30-Minute Reserve
2015 Security Constraints							
PV Level	56	3	9.6 MW/min	27 MW maximum	16 MW maximum	31 MW	27 MW
Thermal Units	3 online						
2016 Security Constraints							
PV Level	67	3	10.9 MW/min	29 MW maximum	16 MW maximum	29 MW	27 MW
Thermal Units	3 online						

Table 4-8. Hawai'i Electric Light 2015–2016 System Security Constraint

Value	Capacity (MW)	Thermal Units Required	Ramp Rate Required	Regulating Reserve: Day Time	Regulating Reserve: Night Time	Contingency Reserve	30-Minute Reserve
2019 Scenario 1 Security Constraints							
PV Level	78	2	12.2 MW/min	32 MW maximum	16 MW maximum	20 MW	22 MW
Thermal Units	2 online						
PV Level	78	3	12.2 MW/min	32 MW maximum	16 MW maximum	20 MW	25 MW
Thermal Units	3 online						
2025 Scenario 2 Security Constraints							
PV Level	89	2	13.6 MW/min	34 MW maximum	16 MW maximum	25 MW	25 MW
Thermal Units	2 online						
PV Level	89	3	13.6 MW/min	34 MW maximum	16 MW maximum	20 MW	25 MW
Thermal Units	3 online						
2025 Scenario 3 Security Constraints							
PV Level	89	2	14.6 MW/min	21 MW maximum	3 MW maximum	25 MW	22 MW
Thermal Units	2 online						
PV Level	89	3	14.6 MW/min	21 MW maximum	3 MW maximum	20 MW	25 MW
Thermal Units	3 online						
2025 Scenario 4 Security Constraints							
PV Level	89	2	17.6 MW/min	54 MW maximum	36 MW maximum	25 MW	22 MW
Thermal Units	2 online						
PV Level	89	3	17.6 MW/min	54 MW maximum	36 MW maximum	20 MW	25 MW
Thermal Units	3 online						

Table 4-9. Hawai‘i Electric Light 2019–2025 Scenarios System Security Constraints

Value	Capacity (MW)	Thermal Units Required	Ramp Rate Required	Regulating Reserve: Day Time	Regulating Reserve: Night Time	Contingency Reserve	30-Minute Reserve
2030 Scenario 1 Security Constraints							
PV Level	97	2	14.5 MW/min	35 MW maximum	16 MW maximum	20 MW	22 MW
Thermal Units	2 online						
PV Level	97	3	14.5 MW/min	35 MW maximum	16 MW maximum	20 MW	25 MW
Thermal Units	3 online						
2030 Scenario 2 Security Constraints							
PV Level	97	2	14.5 MW/min	35 MW maximum	16 MW maximum	25 MW	25 MW
Thermal Units	2 online						
PV Level	97	3	14.5 MW/min	35 MW maximum	16 MW maximum	20 MW	25 MW
Thermal Units	3 online						
2030 Scenario 3 Security Constraints							
PV Level	97	2	15.5 MW/min	23 MW maximum	3 MW maximum	25 MW	22 MW
Thermal Units	2 online						
PV Level	97	3	15.5 MW/min	23 MW maximum	3 MW maximum	20 MW	25 MW
Thermal Units	3 online						
2030 Scenario 4 Security Constraints							
PV Level	97	2	18.5 MW/min	55 MW maximum	36 MW maximum	25 MW	22 MW
Thermal Units	2 online						
PV Level	97	3	18.5 MW/min	55 MW maximum	36 MW maximum	20 MW	25 MW
Thermal Units	3 online						

Table 4-10. Hawai'i Electric Light 2030 Scenarios System Security Constraints

Maui Electric

The amount of legacy DG-PV on the Maui Electric system on Maui island should not exceed 10 MW. Quantities in excess of 10 MW can result in excessive load shedding and the potential for system collapse. Improved relaying and communications are assumed to be installed in 2015 to help mitigate the potential for this consequence.

Maui Electric currently has two BESS connected to its system: one at Kaheawa Two and one at the Auwahi wind generating facilities. One BESS currently only manages the ramp rate of its associated wind generating facility, and the other has 10 MW of reserve available for the Maui Electric system. Years 2017 and 2019 represent significant changes to the Maui Electric system with the addition of substantial amounts of DG-PV and the permanent retirement of the four generating units at Kahului Power Plant.

The system security study for Maui Electric identified the energy requirements for the south Maui system to operate without the construction of new transmission lines to the area.

The system security constraints for Maui Electric are summarized Table 4-11 through Table 4-14. The Thermal Units Required column specifies the minimum number of thermal units required for stability. The remaining columns designate the specific constraint.

Value	Capacity (MW)	Thermal Units Required	Ramp Rate Required	Regulating Reserve: Day Time	Regulating Reserve: Night Time	Contingency Reserve	30-Minute Reserve	DTT Scheme§ Required
Minimum Thermal Units, No EES								
Wind	72	DTCC1 + KPP3, KPP4	12.5 MW	47.25 MW	36 MW	24 MW	40.2 MW	Yes
DG-PV	75							
Largest Unit	30							
Wind	72	DTCC1 + ½ DTCC2 KPP3, KPP4	12.5 MW	47.25 MW	36 MW	45 MW	40.2 MW	No
DG-PV	75							
Largest Unit	30							

§ DTT Scheme refers to a direct transfer trip of the first stage of load shedding for select unit outages. In order to prevent the tripping of the second stage of load shedding, the first stage should be transfer tripped for the loss of the KWP plant or any of the combustion turbines.

Table 4-11. Maui Electric 2015 System Security Constraints

Value	Capacity (MW)	Thermal Units Required	Ramp Rate Required	Regulating Reserve: Day Time	Regulating Reserve: Night Time	Contingency Reserve	30-Minute Reserve	DTT Scheme§ Required
Minimum Thermal Units, No EES								
Wind	72	DTCC1 + KPP3, KPP4	14 MW	49.5 MW	36 MW	45 MW	40.2 MW	No
DG-PV	90							
Largest Unit	30							

§ DTT Scheme refers to a direct transfer trip of the first stage of load shedding for select unit outages.

Table 4-12. Maui Electric 2016 System Security Constraints

The security constraints for years after 2016 (Table 4-13 and Table 4-14) assume that the utility will have the capability to install an energy storage system to meet the criteria.

Value	Capacity (MW)	Thermal Units Required	Ramp Rate Required	Regulating Reserve: Day Time	Regulating Reserve: Night Time	Contingency Reserve	30-Minute Reserve
Minimum Thermal Units, Maximum EES							
Wind	72	DTCC1	14.6 MW	50.4 MW	36 MW	25 MW	38.5 MW
DG-PV	96						
Largest Unit	30						
Wind	72	DTCC1 + ½ DTCC2§	14.6 MW	50.4 MW	36 MW	10 MW	38.5 MW
DG-PV	96						
Largest Unit	30						
Wind	72	DTCC1 + KPP3, KPP4	14.6 MW	50.4 MW	36 MW	10 MW	38.5 MW
DG-PV	96						
Largest Unit	30						
Wind	72	DTCC1 + ½ DTCC2 KPP3, KPP4	14.6 MW	50.4 MW	36 MW	0 MW	38.5 MW
DG-PV	96						
Largest Unit	30						

§ The DTCC1 + ½ DTCC2 minimum unit combination closely matches the 2019 daytime cases since the load increase during the day is offset by the increase in the solar capacity For this reason, 2019 cases were not run.

Table 4-13. Maui Electric 2017 System Security Constraints

Value	Capacity (MW)	Thermal Units Required	Ramp Rate Required	Regulating Reserve: Day Time	Regulating Reserve: Night Time	Contingency Reserve	30-Minute Reserve	Transmission Constraint§
Baseline: Minimum Thermal Units, Maximum EES								
Wind	72	DTCC1	18 MW	55.5 MW	36 MW	25 MW	38.5 MW	No
DG-PV	130							
Largest Unit	30							
Wind	72	DTCC1 + ½ DTCC2	18 MW	55.5 MW	36 MW	20 MW	38.5 MW	No
DG-PV	130							
Largest Unit	30							
NTA-PSH Minimum Thermal Units, Maximum EES								
Wind	72	DTCC1	18 MW	55.5 MW	36 MW	25 MW	38.5 MW	Yes
DG-PV	130							
Largest Unit	30							
Wind	72	DTCC1 + ½ DTCC2	18 MW	55.5 MW	36 MW	10 MW	38.5 MW	Yes
DG-PV	130							
Largest Unit	30							
NTA ICE Minimum Thermal Units, Maximum EES								
Wind	72	DTCC1	18 MW	55.5 MW	36 MW	25 MW	38.5 MW	Yes
DG-PV	130							
Largest Unit	30							
Wind	72	DTCC1 + ½ DTCC2	18 MW	55.5 MW	36 MW	10 MW	38.5 MW	Yes
DG-PV	130							
Largest Unit	30							

1. With the proposed transmission upgrades, the generation dispatch is not constrained by transmission.
2. With a 30 MW PSH located in South Maui, all transmission constraints can be relieved. Minimum frequency for unit trip events are slightly lower compared to the same contingencies with the proposed ICE units located in South Maui.
3. With a 24 MW of ICE units located in South Maui, all transmission constraints can be relieved. Minimum frequency for unit trip events is slightly better compared to the same contingencies with the proposed PSH unit located in South Maui. The difference in response between the PSH and ICE units does not warrant a change in the contingency reserve requirements.

Table 4-14. Maui Electric 2030 System Security Constraints

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5. Preferred Plan

Hawaiian Electric developed this Preferred Plan for transforming the system from current state to a future vision of the utility in 2030 that is consistent with the Strategic Direction (presented in Chapter 2).

Implementation of this Preferred Plan would safely transform the electric system and achieve unprecedented levels of renewable energy production. The electric system of the future would be a balanced portfolio of renewable energy resources, thermal generation, energy storage, and demand response.

This tactical, year-by-year plan for executing this transformation is described and discussed in this chapter.

HAWAIIAN ELECTRIC: UNPRECEDENTED LEVELS OF RENEWABLE ENERGY

The Preferred Plans for the Hawaiian Electric Companies will result in significantly exceeding the Renewable Portfolio Standard (RPS) requirement of 40% by 2030 at each operating company. Table 5-1 depicts the RPS percentages attained through the Preferred Plans for Hawaiian Electric, Maui Electric, Hawai‘i Electric Light, and consolidated for all three. utilities.

Company	Renewable Portfolio Standard
Hawaiian Electric	61%
Maui Electric	72%
Hawai‘i Electric Light	92%
Consolidated	67%

Table 5-1. 2030 Renewable Portfolio Standard Percentages for Preferred Plans

Projection of Compliance with the Renewable Portfolio Standard

As shown in Figure 5-1, the Hawaiian Electric Companies' Preferred Plans will add significantly more renewable energy and substantially exceed the mandated Consolidated 2030 RPS of 40%. This Consolidated RPS would be 67%, and would more than double between 2015 and 2030.

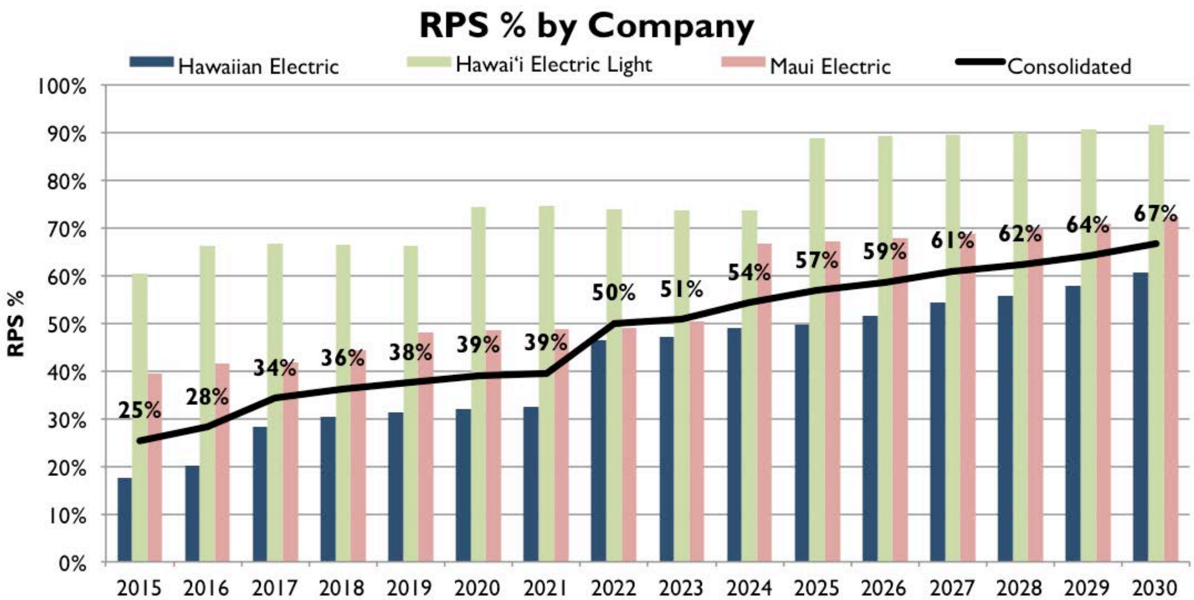

Figure 5-1. Consolidated RPS of Hawaiian Electric Companies Preferred Plans

For the Hawaiian Electric Preferred Plan for O‘ahu, the RPS would more than triple from 2015 to 2030, from 18% to 61%, respectively (Figure 5-2). The relative constribution of distributed generation photovoltaic (DG-PV also referred to as "rooftop PV") will be about one-third of the RPS value.

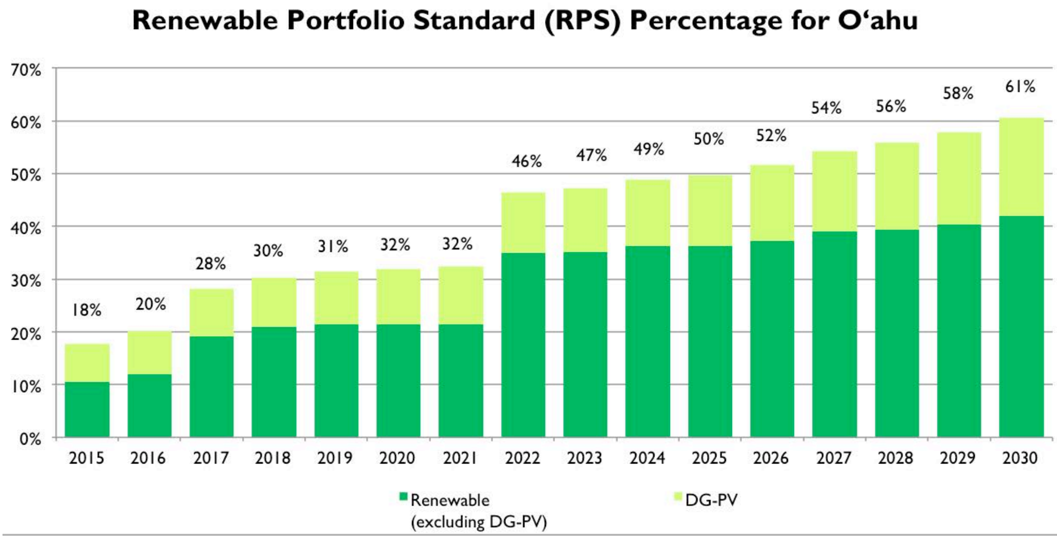

Figure 5-2. Hawaiian Electric Preferred Plan RPS on O‘ahu

The respective contributions of renewable energy resources to the RPS in 2030 are shown in Figure 5-3. Customer-sited generation, which is overwhelmingly DG-PV, would contribute 19% and utility-scale PV would contribute an additional 10%. Wind would contribute 8%. Biomass and waste-to-energy is the largest contributor at 22%. Biofuels account for only 2%.

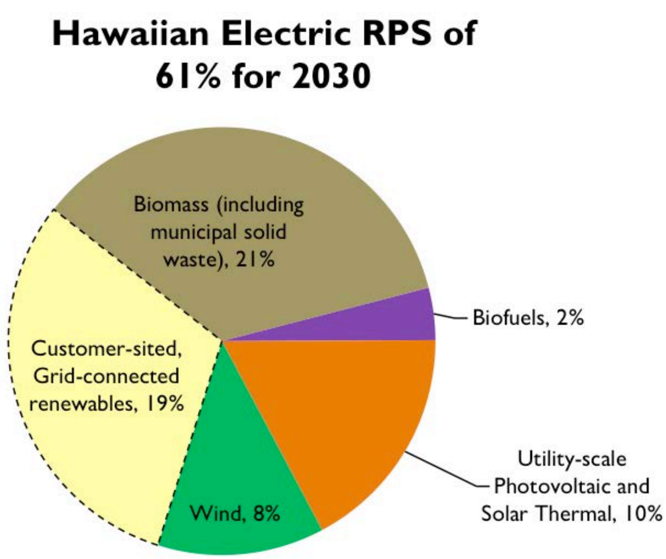

Figure 5-3. 2030 RPS for Hawaiian Electric Preferred Plan

Development of the Preferred Plan

As described in Chapter 2, the Companies developed Power Supply Improvement Plans in two iterative steps:

A. Step A: Define the desired end state for the physical design of the power system in 2030

B. Step B: Define and validate a detailed path to transform from the current state to the desired end state in 2030

Step B was accomplished through application of utility industry accepted planning methods utilizing modeling tools (described in Appendix C), and taking into account the current state, reliability, and financial considerations. The result of this effort is the Preferred Plan.

Hawaiian Electric developed this Preferred Plan through a collaborative, analytical, and innovative process. The PSIP analytics leveraged a Power-Flow and Transient Stability program for transmission grid modeling to assure operability and system stability, and three different production costing simulation models and three modeling teams. The process began with the construction of a Base Plan, then various sensitivity analyses were performed to gain insights on the impacts of the alternatives to the Base Plan. Collaboration between the three teams proved invaluable in providing opportunities for sharing theories and options for improvement based on incremental analytical results. Using three different models, two of which are sub-hourly, as described in Appendix C, was a means for vetting the preliminary results. As illustrated in Figure 5-4, the alternatives that displayed positive impacts to the Base Plan were candidates for incorporation into the Preferred Plan. The resulting Preferred Plan was "tested" by the power-flow-and-transient-stability model to assure system operability, reliability, and stability. The financial outputs from the production simulation of the Preferred Plan were then forwarded to the Financial Model for further analyses (see Chapter 6).

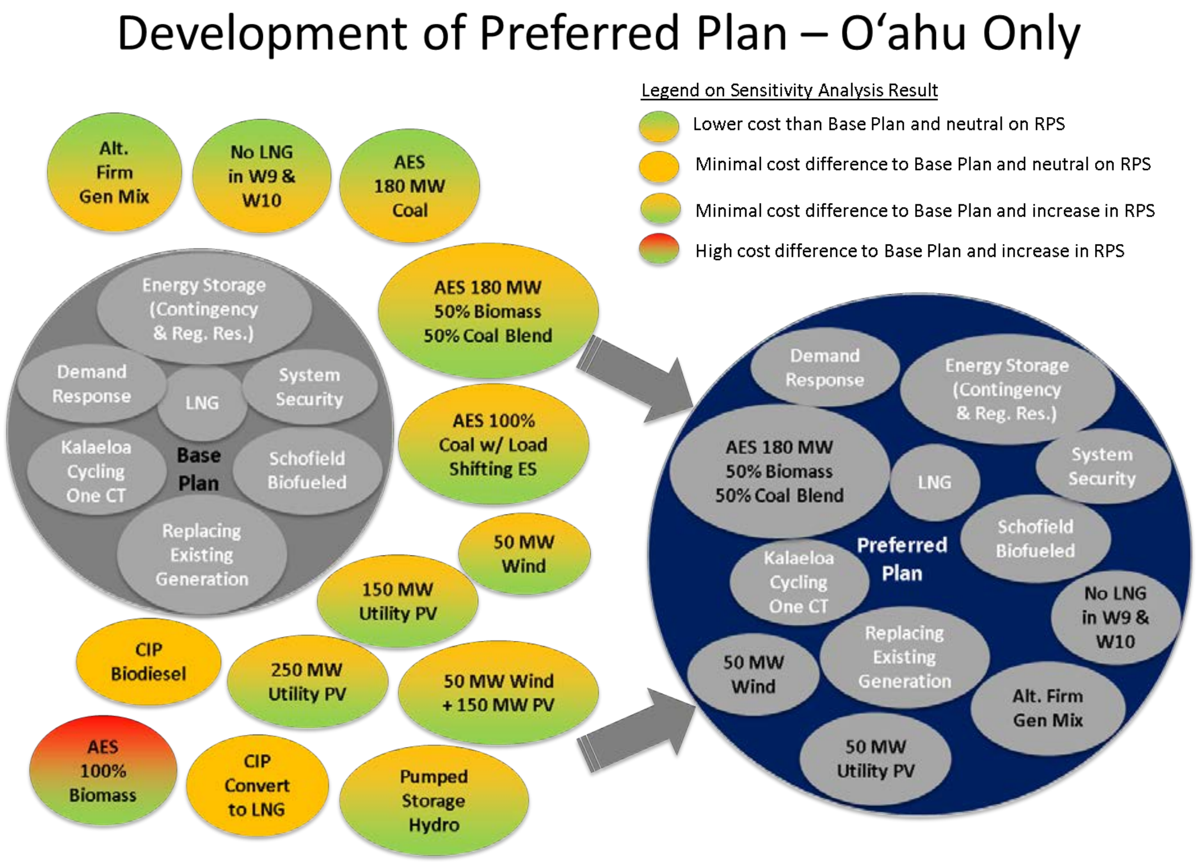

Figure 5-4. Illustration of the Process for Developing the Hawaiian Electric Preferred Plan

The Preferred Plan was developed within a stage-gated, multi-team, analytical, and innovative process. All four elements were critical in developing the Preferred Plan. Collaboration between power system planners, consultants, and Hawaiian Electric leadership was critical in maintaining focus, gaining insights, and meeting the challenge of encouraging independent thinking while maintaining common purpose. Best-of-class analytics were used to construct and evaluate complex plans within a number of contexts: feasibility, costs, risks, flexibility, and sustainability. And while analytics are the centerpiece of the effort, it was critical to search for innovative ways to implement and leverage demand response, energy storage, and variable renewable energy sources.

GENERATION RESOURCE CONFIGURATION

The transformation of the electric system design allows for substantial renewable energy integration. Moreover, this transformation was needed to incorporate significant amounts of energy storage and technologies such as electronic relays for shorter fault clearing times to manage increasing operational challenges at correspondingly higher and higher levels of variable renewable generation.

Each increment of variable generation has to be balanced by firm generation assets (fossil or renewable) and/or energy storage to meet various system reliability criteria. To manage this reality, the firm generation resource mix has to be changed over time. This transformation is made by first increasing operational flexibility of existing steam generating units from baseload to cycling, improved turndown, and enhanced ramp rates, then acquiring new flexible firm generation as these steam generators are retired.

There is also a cost for operating thermal generating units at lower output to manage the regulating reserve requirements that increase each year as more and more variable renewable resources are added to the system. The lower output of the firm, dispatchable assets results in less efficient operations of these assets (similar to car gas mileage is worse at 10 mph than at 50 mph). Additional starts and stops of the thermal generating units to counterbalance the outputs of the variable generation assets are expected to increase maintenance costs.

All of these considerations were considered in the development of the Preferred Plan. (The full process for the development of the Preferred Plan is described in more detail in Appendix L.)

Generation Mix

The Hawaiian Electric Preferred Plan will change over time to this renewable energy future in 2030. Figure 5-5 shows how the energy mix by generation resource transforms over time.

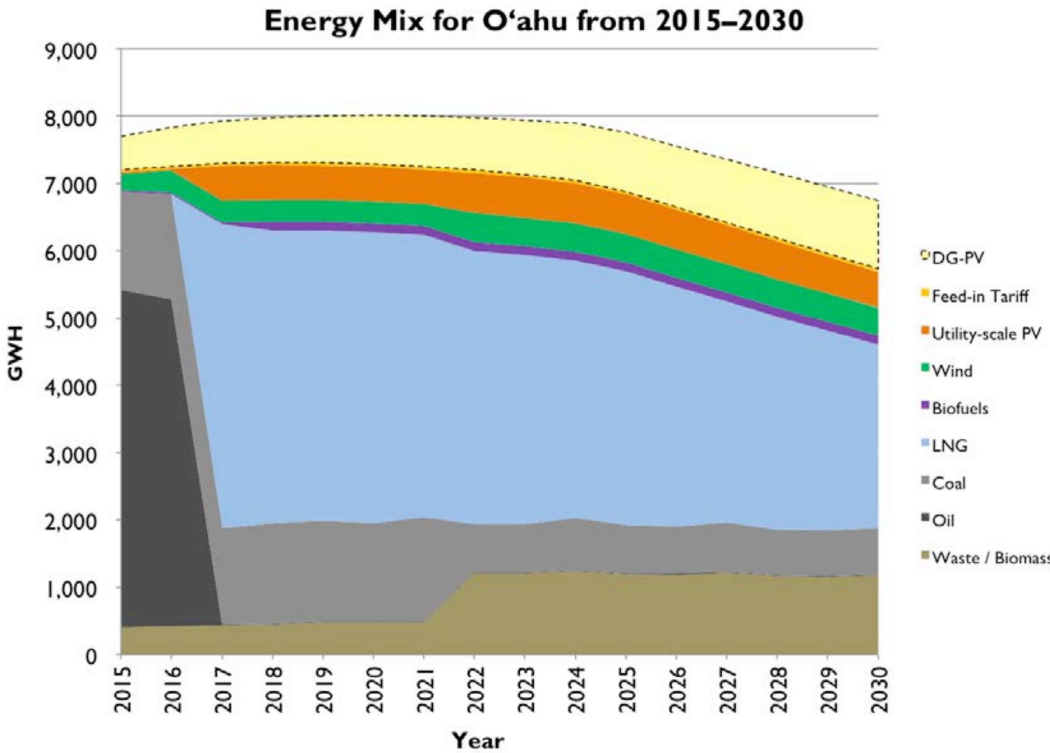

Figure 5-5. Annual Energy Mix of Hawaiian Electric Preferred Plan

The generation mix has increasing levels of renewable energy replacing fossil generation. Renewable energy from distributed PV continues to grow over time and new utility-scale PV and wind are also added to the system. As firm generating units are deactivated and decommissioned, new flexible firm generation is added in their place.

A summary of the generation resources providing in this portfolio mix over time is shown in Table 5-2 below.

Generation Resources for the Preferred Plan ("x" indicates resources included)																
Unit	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
DG PV	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
FIT	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
Kahuku Wind	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
Kawailoa Wind	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
KSEP	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
Kalaeloa Solar 2	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
KREP	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
Na Pua Makani Wind		x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
Mililani Solar			x	x	x	x	x	x	x	x	x	x	x	x	x	x
Waiver Projects			x	x	x	x	x	x	x	x	x	x	x	x	x	x
Kahe PV			x	x	x	x	x	x	x	x	x	x	x	x	x	x
50 MW Wind								x	x	x	x	x	x	x	x	x
50 MW PV								x	x	x	x	x	x	x	x	x
200 MW BESS (Contingency)			x	x	x	x	x	x	x	x	x	x	x	x	x	x
100 MW BESS (Regulation)								x	x	x	x	x	x	x	x	x
HPOWER	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
AES	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
Kalaeloa	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
Kahe 1	x	x	x	x	x	x	x	x	Deactivated	Decommissioned						
Kahe 2	x	x	x	x	x	x	x	x	Deactivated	Decommissioned						
Kahe 3	x	x	x	x	x	x	x	x	x	Deactivated	Decommissioned					
Kahe 4	x	x	x	x	x	x	x	x	x	Deactivated	Decommissioned					
Kahe 5	x	x	x	x	x	x	x	Deactivated	Decommissioned							
Kahe 6	x	x	x	x	x	x	x	Deactivated	Decommissioned							
Waiau 3	x	x	Deactivated		Decommissioned											
Waiau 4	x	x	Deactivated		Decommissioned											
Waiau 5	x	x	x	x	x	x	x	x	x	x	x	x	x	Deactivated		Decommissioned
Waiau 6	x	x	x	x	x	x	x	x	x	x	x	x	x	Deactivated		Decommissioned
Waiau 7	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	Deactivated
Waiau 8	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	Deactivated
Waiau 9	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
Waiau 10	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
Honolulu 8	Deactivated				Decommissioned											
Honolulu 9	Deactivated				Decommissioned											
CT-1	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
Schofield				x	x	x	x	x	x	x	x	x	x	x	x	x
95 MW CT								x	x	x	x	x	x	x	x	x
95 MW CT								x	x	x	x	x	x	x	x	x
58 MW CC								x	x	x	x	x	x	x	x	x
8 MW ICE									x	x	x	x	x	x	x	x
8 MW ICE									x	x	x	x	x	x	x	x
8 MW ICE									x	x	x	x	x	x	x	x
8 MW ICE									x	x	x	x	x	x	x	x
8 MW ICE									x	x	x	x	x	x	x	x
8 MW ICE									x	x	x	x	x	x	x	x
58 MW CC									x	x	x	x	x	x	x	x
42 MW CT									x	x	x	x	x	x	x	x
58 MW CC										x	x	x	x	x	x	x
42 MW CT										x	x	x	x	x	x	x
42 MW CT																x

Table 5-2. Generation Resources for the Preferred Plan, 2015-2030

AES is the single largest generating unit on the O'ahu power system at 180 MW. It currently operates on 100% coal and provides no contribution to RPS. During the course of the PSIP analyses, consideration was given to limit the output to 90 MW for system reliability and/or to convert the operation from coal to biomass. In the Preferred Plan, AES is retained at 180 MW and operated at a blend of 50% biomass and 50% coal from 2022. This did not appear to be the most economical choice, but from a planning perspective it provides the greatest optionality and a very significant contribution to RPS. Depending on what coal and biomass prices turn out to be, and depending on the need for RPS or lower cost, we will have the optionality to adjust operations at any time in the best interests of our customers. Converting AES to 50% biomass would contribute about 10% to RPS in 2022 as shown in Table 5-3 and Figure 5-6 below.

Additions of 50 MW of wind and 50 MW of utility-scale PV also contributes to an incremental 1% to RPS, respectively.

RPS for O'ahu	2021	2022
Biomass and Waste-to-Energy	6.9%	17.5%
Utility-scale PV	8.0%	9.3%
Wind	4.7%	6.2%
Biofuels	1.9%	1.9%
Customer-sited, grid-connected renewables	10.9%	11.4%
Total	32.4%	46.4%

Table 5-3. RPS Comparison of 2021 vs. 2022

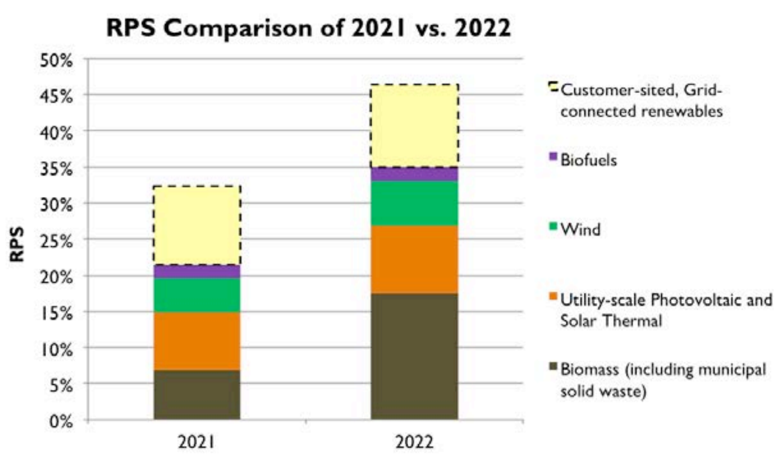

Figure 5-6. RPS Comparison of 2021vs. 2022

Our top priorities are providing safe and reliable service for our customers, and this starts with planning to maintain an adequate amount of capacity to meet our customers' needs. Hawaiian Electric's Preferred Plan complies with current capacity planning criteria[29], as well as draft planning criteria (BAL-502) provided in Appendix M. The draft planning criteria in BAL-502 includes providing capacity values to demand response, utility-scale variable renewable generation, and energy storage. For the purposes of the PSIP, a minimum of 30% reserve margin was targeted. In Table 5-4, the evolution of the energy mix is shown, including the resulting reserve margin. The timeline for adding and retiring generation resources in shown in Figure 5-7. Resources being added to the power system are shown "above the dateline" and resources being retired are shown "below the dateline."

Hawaiian Electric Preferred Plan												
Year	Peak (MW)	Total Firm Capacity (MW)	New Firm Capacity (MW)	Deactivated Firm Capacity (MW)	Demand Response (DR) for Capacity (MW)	Energy Storage for Capacity (MW)	Wind Capacity Value (MW)	Resource Notes (SCCT= Simple Cycle Combustion Turbine) (CC = Combined Cycle) (ICE= Internal Combustion Engine)	Reserve Margin (%) Base	Reserve Margin (%) w/DR	Reserve Margin (%) w/ Energy Storage	Reserve Margin (%) w/ Capacity Value of Wind
								Firm Capacity Demand Response Energy Storage Capacity Value of Wind	✓	✓ ✓	✓ ✓ ✓	✓ ✓ ✓ ✓
2015	1,195	1,655	0	0	24	0	10		38%	41%	41%	42%
2016	1,199	1,655	0	0	27	0	12		38%	41%	41%	42%
2017	1,223	1,561	0	-94	31	0	12	Waiau 3 & 4 deactivated 200 MW Contingency BESS	28%	31%	31%	32%
2018	1,229	1,610	49	0	34	0	12	50 MW Schofield Plant added	31%	35%	35%	36%
2019	1,238	1,610	0	0	38	0	12		30%	34%	34%	35%
2020	1,239	1,610	0	0	42	0	12		30%	34%	34%	36%
2021	1,230	1,610	0	0	42	0	12		31%	36%	36%	37%
2022	1,223	1,591	249	-268	42	0	17	2 x 95 MW SCCT added 1 x 58 MW CC added Kahe 5 & 6 deactivated 100 MW Regulating Battery 50 MW Utility PV 50 MW Wind AES @ 180 MW (50/50 Biomass/Coal)	30%	35%	35%	36%
2023	1,203	1,575	149	-164	42	0	17	6 x 8 MW ICE added 1 x 58 MW CC added 1 x 42 MW SCCT added Kahe 1 & 2 deactivated	31%	36%	36%	37%
2024	1,195	1,504	100	-171	42	0	17	1 x 58 MW CC added 1 x 42 MW SCCT added Kahe 3 & 4 deactivated	26%	30%	30%	32%
2025	1,165	1,504	0	0	42	0	17		29%	34%	34%	35%
2026	1,120	1,504	0	0	42	0	17		34%	39%	39%	41%
2027	1,075	1,504	0	0	42	0	17		40%	46%	46%	47%
2028	1,030	1,396	0	-108	42	0	17	Waiau 5 & 6 deactivated	35%	41%	41%	43%
2029	984	1,396	0	0	42	0	17		42%	48%	48%	50%
2030	948	1,268	42	-169	42	0	17	1 x 42 MW SCCT added Waiau 7 & 8 deactivated	34%	40%	40%	42%
Total			589	-976								

Table 5-4. Reserve Margin for the Hawaiian Electric Preferred Plan

[29] Docket No. 2012-0036, Integrated Resource Planning, Appendix L: Capacity Planning Criteria.

Capacity Value of Variable Generation and Demand Response

Accurately assessing the capacity value of variable generation and demand response resources are critical components toward meeting customer demand and maintaining system reliability.

Capacity Value of Wind and Solar

Wind was assigned a capacity value of 10% of nameplate capacity. This 10% capacity value was determined using a statistical correlation of variable generation output during the peak hour of each day. A 90% probability level was used to determine the capacity value.

PV was not assigned any capacity value due to the annual peak of the system occurring in the evening when PV is not accounted for.

Capacity Value of Demand Response

The demand response programs defined in the *Integrated Demand Response Portfolio Plan* (IDRPP)[30] that are expected to provide capacity value are included in the calculation for the reserve margin. (See Appendix F for details on the assumptions used in the PSIP for Demand Response.)

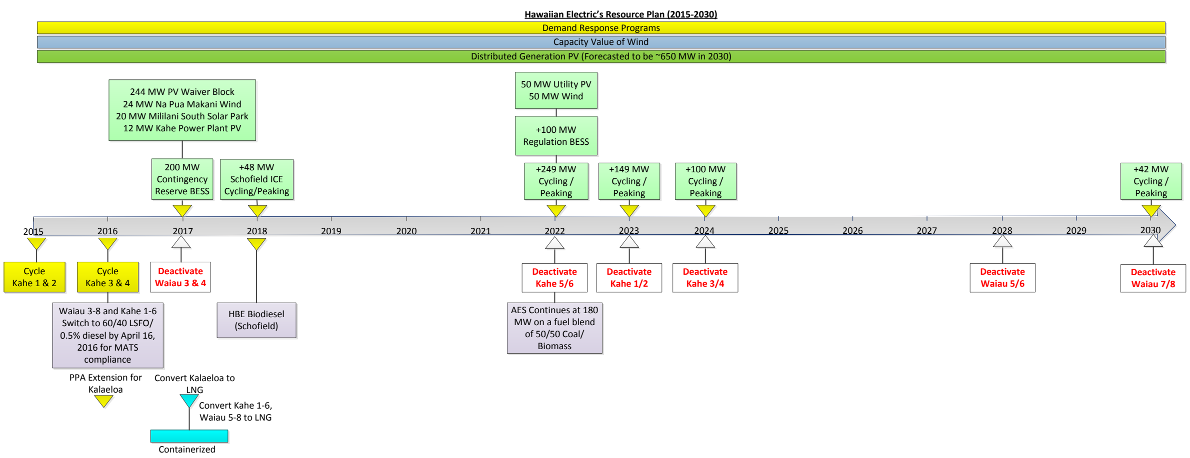

Figure 5-7. Timeline Diagram of Hawaiian Electric Preferred Plan

System Reliability

To move to a future with substantial variable renewable energy, the physical design of the system must be able to operate safely and reliably. The criteria and requirements for developing a plan to adequately accomplish this was described in Chapter 4 and

[30] The Companies filed its *Integrated Demand Response Portfolio Plan* (IDRPP) with the Commission on July 26, 2014.

Appendix M. In addition to regulation of system frequency, voltage must be regulated and maintained within the limits specified in the PUC's General Order No. 7, Section 7.2. All the generation and transmission planning criteria are met to achieve the unprecedented levels of RPS in the Preferred Plan.

Annual Fuel Consumption

Figure 5-8 shows how the annual fossil fuel consumption for Hawaiian Electric's baseload and cycling generating units decreases as these generating units are retired from 2022 to 2030.

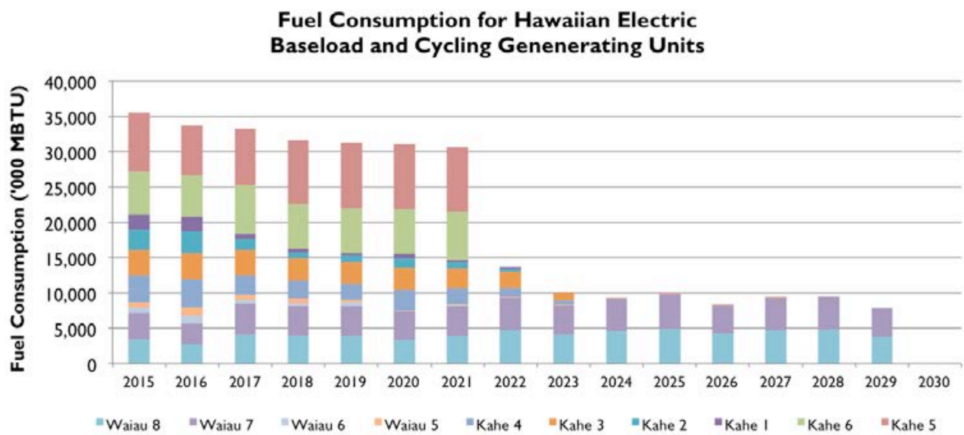

Figure 5-8. Annual Fuel Consumption for Hawaiian Electric Baseload & Cycling Generating Units

ROLES OF GENERATION RESOURCES

The operation of the firm generation resource mix will change over time. This transformation begins by increasing the operational flexibility of existing steam generating units at Kahe and Waiau Power Plants, including conversion of the duty cycle from baseload to cycling, expanded turndown range, and enhanced ramp rates. This increased operational flexibility is particularly critical until energy storage is added, demand response programs are implemented and contributing, and new flexible firm generation is acquired.

Increasing Operational Flexibility of Existing Steam Generators

Hawaiian Electric has reviewed current generating unit operation, previous cycling and turn-down studies, Electric Power Research Institute (EPRI) publications, and other relevant industry literature. We have taken a holistic approach to operational flexibility and are working to change procedures and policies accordingly. Historic limitations such as having all burners in service are being evaluated and modified as applicable. Flexibility in this context refers to unit turn down, on/off cycling ("daily cycling"), and ramp rates. These items are not one or the other, but rather optimizing each of them.

On/Off (Daily) Cycling

Enabling the base loaded units to operate in an on/off cycle mode (that is, daily cycling) would maximize variable renewable generation by lowering the amount of must-run generation on the power system. Kahe Units 1–4 and Waiau Units 7 & 8 will be able to do daily cycling as necessary. It is unlikely that Waiau 7 & 8 will cycle because system reliability criteria currently require two units to be online at Waiau at all times. For that reason we do not anticipate cycling Waiau Unit 7 or Waiau Unit 8. We will, however, be modifying procedures and practices for when or if it becomes necessary. Kahe Units 1–4 will be able to cycle daily as necessary. Based on preliminary testing, it is expected that Kahe Unit 1–4 and Waiau Units 7 & 8 will be able to perform "hot start ups" in 3.5 hours or less. That is, the startup time from "putting fires in the boiler" to "firm" (ready for full dispatch) will be 3.5 hours or less.

The ability to change operation from baseload to cycling is largely based on procedures, training, and technical review of the units' capabilities. Commensurate with cycling, there is increased maintenance and wear and tear on the equipment. We do expect this and envision the need to implement improvement projects to enhance the cycling ability as necessary. Potential modifications would include enlarging super heat header drains, reheat header drains, and turbine throttle drains to allow for better temperature control during startup. Additional potential modifications include nitrogen gas blanket systems to prevent air leakage during shutdown and turbine bypass systems to protect the reheat section of the boilers. Projects are to be selected based on anticipated cycles and benefit to the system and for customers.

In June 2013, a cycling test was conducted on Kahe Unit 3, and we successfully demonstrated the ability to cycle each day from June 16–20. The average startup times was 2.6 hours. The demonstration test proved that the "90 MW" steam units are capable of daily cycling.

We are also evaluating our startup practices on Waiau Units 5 & 6, which are already cycled daily, and expect to improve their start times to be consistent with what is planned for Kahe Units 1–4 and Waiau Units 7 & 8.

Kahe Units 5 & 6 are not suitable for daily cycling. The units have operating constraints that make daily cycling challenging or infeasible. However, Kahe Units 5 & 6 are candidates for seasonal layup should that could provide benefit for the system operation.

Expanded Turn Down Range

The baseloaded units are also being evaluated for expanded turndown to lower loads. Currently the minimum load on Kahe Units 1–4 and Waiau 7 & 8 is 25 MW (gross). To achieve further lower minimum loads, as a first step, we reviewed EPRI publications, OEM documentation, a 1992 Hawaiian Electric/Stone & Webster Variable Pressure Operation study, a Hawaiian Electric/Stanley Consultants Flexibility Study, and miscellaneous industry publications. In the previous Hawaiian Electric empirical studies, the limitations to turn downs were evaluated. In most cases, changes to procedures and policy will allow reduction in defined minimum load points. For example, modification of requirements for maintaining drum pressure and 'all' burners in service allow for much improved unit flexibility. A circulation study for low load conditions on Kahe Unit 1 is being conducted. Further studies will be recommended based on the outcome of the Kahe Unit 1 circulation study. No major limitations are expected and recommended modifications will be considered based on significance, cost, and value.

Kahe Units 1–4 and Waiau Units 7& 8 are expected to have unit minimums reduced to 5 MW (gross). Reducing unit minimums to 5 MW (gross) will provide enhanced flexibility to the power system as the unit is providing almost zero net output.[31] And, for this operating condition, the unit could ramp up to full load without having to proceed through a startup and synchronization protocol. Depending on the duration of the low load, operating in this condition will provide the same benefits as taking the unit offline while using less fuel than for a startup. Exact economics are being further evaluated but operating at 5 MW (gross) for 6 hours appears to use about the same amount of fuel as one hot start up. More importantly, with the generating units operating at 5 MW (gross), they still provide ancillary services not provided by variable generation, including dispatchable VARS, system inertia, and short circuit current.

During the period of June 16–20, 2014, a demonstration of low load operation was conducted on Kahe Unit 3; it was operated for extended duration at 5 MW (gross) with reduced drum pressure. Boiler, turbine, and balance of plant equipment were monitored for performance and limitations that may hinder the low load operation. Ultimately it was deemed that all required operating parameters remained within limitations.

Operating at such reduced minimum loads and then ramping to higher loads would induce large thermal cycles on the equipment. While the thermal cycle is less than that of daily cycling, there is still associated wear and tear and increased maintenance associated with such operation. While procedural changes, operating policy modification, and operator training represent the largest part of enabling enhanced turndown, certain improvements will certainly enhance operational flexibility. Modifying the boiler feed pumps to operate in variable speed will greatly enhance the capabilities of the

[31] The auxiliary load is approximately 4 MW, and the output to the system is approximately 1 MW (net).

condensate system. At the reduced loads, the current fixed speed pumps operate well off their best efficiency points. At low loads, the existing pumps operate in a manner that will compromise reliability and increase maintenance cost. Similarly, the feed regulator valves operate at a point that will compromise reliability and increase maintenance. Variable speed boiler feed pumps is an example of a capital improvement that will enhance unit flexibility. Variable speed force draft fans will provide similar improvement in operational flexibility. Control system tuning will also be necessary to improve operation at low loads and to automate some manual operations.

At megawatt levels less than 20 MW (gross), some form of sliding (that is, reduced) drum pressure is necessary for operations of Kahe Units 1–4 and Waiau Units 7 & 8. This reduced pressure operations helps reduce thermal stress on the steam turbine and improves circulation in the boiler tubes. There are system consequences that need to be considered when operating units at this reduced pressure. Specifically, unit response to system disturbances will not be as robust as with the unit at full pressure. The unit will have multiple burners removed from service and at reduced pressure will mean reduced capacity when at these low loads. The units will not be able to ramp as fast with the reduced pressure. However, depending on system conditions, the benefits of reduced minimum loads will be more valuable than negative implications.

Kahe Unit 5 minimum load will also be reduced. Work and testing will be conducted to prove that Kahe Unit 5 can safely and continuously operate at reduced pressure, and with less than all burners in service at load down to 25 MW (gross).

Kahe Unit 6 minimum load will remain at 45 MW (gross). Kahe Unit 6 has emission limitations that will prevent operation below the current minimum of 45 MW (gross).

Ramp Rates

Kahe Units 1 & 2 and Waiau Units 7 & 8 will have adjusted ramp rates of 4 MW/minute at full pressure when in the normal operating range (that is, at loads above 30 MW (gross)). Control tuning and enhancement will be necessary to allow for this change. At reduced load pressures, it is estimated that ramp rates will be 2 MW/minute.

Kahe Units 3 & 4 have modern turbine control systems and therefore have an enhanced ability to run in coordinated control. Kahe Units 3 & 4, when at full pressure and in the normal operating range (above 30 MW), will be able to ramp at 5 MW/minute. At reduced load and pressure, the unit will be able to ramp at 2 MW/minute.

Kahe Units 5 & 6, when at full pressure and in the normal operating range, will be able to ramp at 3 MW/minute. Kahe Unit 5, when at reduced pressure and load, will be able to ramp at 2 MW/minute.

Ramp testing and tuning will be conducted on each unit. Proposed ramp rates are based on testing conducted in the 2009–2012 time frames. Enhancements to coordinated control systems logic will be necessary to ensure these rates are achieved without negative consequences. Upgrades to the "GCRTU" (communication and control between the generating unit and System Operation) will also enhance the ability to improve ramp rates. These projects are already planned.

Operational flexibility will be improved on our generating units. The units will be able to operate in modes that best meet system demands. Summary of unit operating conditions are presented in Table 5-5.

Unit	current		near future				
NPO = Norm Oper. Pressure VPO=Variable Pressure Op (hybrid)	ramp rate	Pmin	ramp rate[15]	Pmin5, MWg	BURNERS PULLED[9]	Pmax (when at Pmin)[2,19]	hot start time online/full load (hrs)[7]
K1 NOP	2.5	25	4	25	1	86/86	2.5/3.5
K1 NOP			4	20	2	69/86	
K1 VPO (900psi)			2	5	4 (estimate)	43	
K2 NOP	2.5	25	4	25	0	86/86	2.5/3.5
K2 NOP			4	20	0	86/86	
K2 VPO (900psi)			2	5	4 (estimate)	43	
K3 NOP	2.5	25	5	25	0	90/90	2.5/3.5
K3 NOP			5	20	3	72/90	
K3 VPO (900psi)			2	5	8-9	45	
K4 NOP	2.5	25	5	25	1	89/89	2.5/3.5
K4 NOP			5	20	3	66/89	
K4 VPO (900psi)			2	5	8-9	45	
K5 NOP	2.5	45	3	70	0	142/142	4/6
K5 NOP				45	2	135	
K5 VPO			2	25	?		
K6 NOP	2.5	45	3	45	2	135	
W7 NOP	3	25	4	25	1	87/87	2.5 / 3.5
W7 NOP			4	20	3	69/87	
W7 VPO (900 psi)			2	5	8-9		
W8 NOP	3	25	4	25	1	90/90	2.5 / 3.5
W8 NOP			4	20	3	69/90	
W8 VPO (900 psi)			2	5	8-9		

Table 5-5. Hawaiian Electric Ramp Rate Improvements

Key Generator Utilization Plan

The following discussion is presented in recognition of the unique economic and operational challenges that exist for key O‘ahu generating units.

AES Hawai‘i (AES)

AES operates on coal and provides the lowest cost energy to the power system on O‘ahu. The existing Power Purchase Agreement (PPA) between AES and Hawaiian Electric expires on September 1, 2022. AES has represented to Hawaiian Electric that it is currently under financial distress, primarily because there is no financial reserve at the project (historical profits from AES have been paid as dividends to its parent company) and energy payments made to AES under the PPA pricing formula may not fully cover their cost of coal under conditions of high annual capacity factors. It would be in our customers' financial interest to keep AES operating on the system without interruption under the terms of the existing PPA.

For the past 22 year, AES has operated with high availability and has been scheduled for operation (that is, synchronized to the grid) whenever it was available. Having the lowest marginal cost of energy, it is typically dispatched to full capacity whenever it is online and system load demand can safely accommodate the output from AES. As more variable renewable generation is available on the O‘ahu grid, however, AES presents operational challenges due to its relatively large capacity (AES is the largest single "contingency" on the O‘ahu grid) and lack of operational maneuverability. Consequently, AES defines the limits of the amount of spinning reserve and/or energy storage required to meet transient system security criteria.

Given the potential financial impact of an interruption of service associated with a financial default of AES, Hawaiian Electric has been negotiating in good faith with AES to explore the possibility of an amendment to the PPA that would provide financial relief to AES under conditions that are in the best interests of our customers. Any agreement between AES and Hawaiian Electric for an amendment to the PPA would be submitted for Commission review and approval.

As part of the ongoing negotiations for an amendment to the PPA, Hawaiian Electric has requested a no-cost option to convert some or all of the energy produced at the AES facility from coal to biomass (for example, "black pellets from wood"). Hawaiian Electric believes that AES could provide superior optionality for the O‘ahu power system to optimize between cost and Renewable Portfolio Standard (RPS) should AES have the capability to operate on coal and biomass. To date, Hawaiian Electric has not received a specific proposal from AES to this effect. However, as part of the PSIP analysis, Hawaiian Electric evaluated the potential effects on costs and contributions toward the RPS should some or all of the AES capacity be converted from coal to biomass.

New rules and regulations at the state and federal levels limiting green house gas (GHG) emissions are likely to affect, and perhaps limit, operations and/or the cost of generation of AES. Hawaiian Electric will continue to work cooperatively with AES to understand the ramifications of these rules and regulations, and the options for compliance.

As shown in its Adequacy of Supply report filed April 11, 2014, Hawaiian Electric currently needs the 180 MW of capacity provided by AES in order to meet its generating system reliability guideline of 4.5 years per day. Without AES, it is estimated there could be a reserve capacity shortfall of about 150 MW. Conversely, as previously mentioned, based on recent transient stability analysis, the O'ahu grid is not currently meeting its system security criteria when AES is operated at 180 MW during daytime operating period when there is significant amounts of variable renewable generation on the O'ahu grid.[32]

The AES facility is expected to be a viable generator after the expiration of the existing PPA and would be a candidate for a new PPA in the succeeding time period, provided the operating limitations, environmental limitations, fuel optionality, and pricing permit are worked out. Because AES is an IPP, it is impossible to identify its value in the future without a finalized contract identifying pricing, operating flexibility, and its contribution to RPS.

Kalaeloa Energy Partners (KPLP)

KPLP is a combined-cycle combustion turbine generator that currently operates on low sulfur fuel oil (LSFO). The Power Purchase Agreement (PPA) between KPLP and Hawaiian Electric will expire on May 23, 2016. As shown in its Adequacy of Supply report filed April 11, 2014, in the absence of new capacity, Hawaiian Electric needs KPLP's capacity of 208 MW to meet the generating system reliability guideline. In the absence of KPLP, it is estimated that there would be a reserve capacity shortfall of about 175 MW.

Hawaiian Electric is currently negotiating in good faith with KPLP for an extension to the PPA for six years, to approximately 2022. Among the terms being negotiated are: (1) the term of the extension; (2) fuel flexibility including LNG; and (3) operational flexibility including increased turndown to lower loads and extended simple-cycle operation. KPLP has represented that it needs to invest substantial capital to address equipment deterioration, so that it would be able to operate at high levels of reliability beyond the term of the existing PPA, and this is being considered in the negotiations.

[32] In an April 2013 event in which the loss of the largest generator (AES) on Hawaiian Electric's system resulted in the system frequency reaching 58.35 Hz, which initiated three blocks of under-frequency load shed.

At an appropriate price and with appropriate operate operating flexibility, KPLP represents a viable future generator for the Oʻahu power system, especially if it converts to LNG. Unfortunately, the KPLP facility does not have adequate space for LNG storage or regasification. Accordingly, Hawaiian Electric is considering installing such facilities at its property that abuts the KPLP facility, and the possibility of providing natural gas to KPLP from these facilities. Any final agreement would be reflected in an amendment to the PPA that would be submitted for Commission review and approval.

The KPLP facility is expected to be a viable generator in 2022 after the expiration of the potential six-year extension to its PPA, and would be a candidate for a new PPA in the succeeding time period. Because KPLP is an IPP, it is impossible to identify its value in the future without a finalized contract identifying pricing, operating flexibility, and other parameters.

Campbell Industrial Park Combustion Turbine No. 1 (CT-1)

CT-1 is a combustion turbine that currently operates firing biodiesel and is the type of generating unit that is compatible and complementary on a power system with increasing amounts of variable renewable generation. CT-1 provides offline reserve, online spinning reserve, and can be turned on and synchronized to the grid within 22 minutes. It can also be readily turned off in order to accept more variable renewable generation onto the grid. When operating, it contributes a relatively high level of system inertia, can help manage system frequency by responding to minute-to-minute load demand control signals, and can ramp up rapidly to offset rapid down ramps of variable renewable generation.

In comparison to Hawaiian Electric's steam units, AES, and KPLP, the fuel efficiency of CT-1 is lower. For example, at maximum load, its fuel efficiency is about 11,700 Btu/kWh-net. Kahe Unit 6 has a fuel efficiency of about 10,050 Btu/kWh-net at full load. In combination with the higher cost of biodiesel compared to LSFO, CT-1 is the highest cost generator on the Oʻahu power system.

Because CT-1 provides valuable ancillary services when it is operating, it would be advantageous to reduce its operating cost. Hawaiian Electric is considering whether to seek approval to operate on lower cost fuels, such as diesel oil and/or LNG. The biodiesel currently used in CT-1 is supplied by Renewable Energy Group via a contract that has a minimum purchase amount of 3 million gallons per year. This contract expires in November 2015. Hawaiian Electric recently issued a Request for Proposal (RFP) for a new biofuel contract. Whether operated on biofuels or an alternative less expensive fuel, CT-1 represents a vital resource for the Oʻahu system due to the operating characteristics. The frequency with which CT-1 is operated will depend on the fuel utilized and system conditions.

Kahe Units 5 and 6

Kahe 5 and 6 are the largest steam generators that are owned and operated by Hawaiian Electric, each rated at 142 MW. Kahe 5 and 6 currently operate on low sulfur fuel oil (LSFO). As part of the PSIP analyses, Hawaiian Electric's evaluated the deactivation and decommissioning of Kahe Units 5 and 6 within the 2015–2030 study period. Due to the relatively large size of these generating units, they pose incrementally more risk to the stability of the power system if they suddenly trip at full capacity as compared to the other steam units (similar to AES). Accordingly, they have been identified for deactivation and decommissioning as the next units following Waiau Units 3 and 4, and to be deactivated as soon as 2022, assuming replacement capacity resources necessary to meet system requirements are available

Kahe 5 and 6 are also required to be operated on cleaner fuels as early as April 2016 to comply with new environmental air regulations. Accordingly, Kahe 5 and 6 are candidates to be converted to operate on LNG or a blend of LSFO and low-sulfur diesel. If Kahe 5 and 6 continue to operate beyond 2022 and LNG is not available, they may have to be operated on ultra-low-sulfur-diesel oil for purposes of environmental compliance.

Other Generating Units Owned and Operated by Hawaiian Electric

In order to reduce costs to customers, Hawaiian Electric is pursuing the use of LNG in its fleet of steam units (excluding Honolulu Units 8 and 9 and Waiau Units 3 and 4). Hawaiian Electric plans to add LNG-firing capability to Waiau Units 5 to 8 and Kahe Units 1 to 6 and be LNG-capable by 2017. All of these steam units are candidates for retirement before 2030, as replacement capacity resources necessary to meet system requirements become available. Conversion of Waiau 9 and 10 and CT-1, all simple-cycle combustion turbines, are candidates to be converted to LNG operation, and such conversions will be evaluated.

Role of Thermal Generation in the Future

With increasing energy efficiency measures, continued growth of distributed generation, and increasing utility-scale renewable generation, we expect declining utilization of thermal generating units that are fossil-fuel fired. Despite this decreasing role in energy production, the aggregate capacity of the thermal units will still need to exceed the annual peak load (plus additional capacity to cover reliability and maintenance contingencies). Peak loads on the Oʻahu power system occur during the early evening hours when solar generation is zero and wind energy cannot be counted upon. In summary, the thermal generation fleet is predominately to be used during "nighttime" hours and the typical capacity factors for the fleet will be low-to-moderate. Moreover, if load-shifting energy storage (for example, pumped storage hydroelectric and/or flow batteries) were implemented on the Oʻahu power system in the future, the operational duty and capacity factors of the thermal generating units would diminish further. However, they would still be required to "back up" the variable renewable energy and energy storage systems for those situations when there is no alternative to meet system load demand other than by relying on the thermal generation fleet.

The lower utilization rate of the thermal generation fleet may still require the building of new "replacement" generating units to meet reserve margin requirements and/or yield economic benefit through improved thermal efficiencies. To protect customers from unnecessary rate impacts, in our plan we defined a tactical strategy leveraging an optimized combination of new units and conversion of existing suitable units as the most economical solution for our customers. New units can be more efficient, operate with a lower minimum load, provide faster-ramp rates for system security and support the integration of more renewables. However, these units require significant capital investments and have a long-lead time before becoming operational. Old units are less efficient but with conversion of the most suitable units to LNG—assuming limited capital investment—can contribute to decreasing fuel costs under the expected relatively low utilization rates.

Although this does not appear to be the lowest possible cost, the PSIP envisions retirement of all the utility's steam generating units by 2030 due to their age, and consistent with the PUC's inclinations. The plan assumes they are replaced with more efficient and operationally-flexible generating units. The specific decisions and timing to replace the existing generating units is assumed in the analyses, but actual dates may, and probably will, vary somewhat based on actual circumstances.

Plan for Retiring Fossil Generation

When firm generating units are in operation, they provide not only capacity and energy, they provide reactive power to help regulate regional voltage with tariff limits. In some instances, firm generating units must be operated even if a sufficient amount of generation is in operation in order to provide reactive power to certain parts of the grid. For example, two Waiau steam units are operated at all times in order to provide reactive power to support voltages on the east side of the island. If there are no units operating at Waiau, all firm generation would be on the west side of the island (at Kahe and Campbell Industrial Park) while most of the load is on the east side of the island. Voltages would drop significantly as power is delivered over the transmission system from the west side of the island to the east side. The Waiau units are operated to support voltages at the load center.

In the future, if the Waiau units are deactivated or decommissioned and replacement generation is not located in the same proximity, the units could be converted to synchronous condensers, which would provide reactive power to help regulate voltage.

As discussed below, the Preferred Plan has all the existing steam generating units deactivated and/or permanently retired by 2030. In general, a generating unit will be retired two years after it is deactivated. For example, Kahe Units 5 & 6 are planned for deactivation in 2022 and will be retired in 2024. The exception to this general guideline is Honolulu 8 & 9 due to violations of the current capacity planning reliability guideline in the near-term until the Schofield Generating Station is in service. Accordingly, Honolulu Units 8 & 9 and Waiau Units 3 & 4 are expected to retire in 2019.

The deactivation plan for all steam units was developed on a systematic basis. In order to provide best value to the customer in terms of cost reduction, it was deemed necessary to retire units as a pair. Our unit pairs share one control room, operator staff, and common equipment. In order to maximize cost reduction, the unit pair should be retired together. Waiau 5 & 6 is a cycling unit pair that will not be retired as it is already a flexible unit.

- Kahe Units 5 & 6 will be the first unit retirement following Waiau Units 3 & 4 and would be the first baseload units to be retired. The existing plan would be to deactivate Kahe Units 5 & 6 in 2022. As previously stated, we recognize the need to improve the flexibility of our generating system in order to accommodate more variable renewable generation. Deactivating Kahe Units 5 & 6 maximizes the amount of variable renewable generation in two ways. First, the retirement of Kahe Units 5 & 6 will remove 284 MW (gross) of thermal generation from the power system, and will provide the complementary benefits of allowing more megawatts of variable renewable generation to be online and the remaining generating units to run at higher more efficient loads. The second reason for choosing to retire Kahe Units 5 & 6 following Waiau Units 3 & 4 is to increase system operational flexibility. Due to the size, design, and environmental permit constraints, Kahe 5 & 6 are the least flexible steam units on the system. Kahe 5 & 6 have the least ability to turn down, least flexible with ramping, and least flexible with regard to system disturbances. The combination of these reasons makes Kahe 5 & 6 attractive to retire before the other thermal generators.
- Kahe Units 1 & 2 would be the next pair of baseload units to be retired. The selection of Kahe Units 1 & 2 at this point is based on age. Kahe Units 1 & 2 are the oldest of the baseload units and offer less operational flexibility than Kahe Units 3 & 4. That is, Kahe Units 3 & 4 have modern turbine control systems and have turbine features such as hood sprays that will facilitate low load operation. Kahe Units 1 & 2 are scheduled for deactivation in 2023.
- Kahe Unit 3 has a second fuel system which was installed for biofuel and LSFO mixing. Maintaining Kahe 3 provides fuel flexibility until the potential use of biofuels does not exist. Kahe 3 & 4 are scheduled for deactivation in 2024.
- Waiau Units 5 & 6 are currently daily cycling units. They are shown to remain in service through 2028. If replacement generation is not installed in the proximity of the Waiau

Power Plant, then Waiau Units 5 & 6 may be converted to synchronous condensers to provide voltage support to the grid when Waiau Units 7 & 8 are deactivated.

- Waiau Units 7 & 8 will be the last of the existing steam units on Oʻahu to be retired. The reason for this is to provide system flexibility by having some generation closer to the load centers. As mentioned previously, at least two generating units at Waiau are required to run at all times. While system conditions will change in the future, the flexibility of ensuring generation is available close to the load center will ensure the maximum system flexibility and security is maintained.

Plan for New Generation

To create the Oʻahu electric system of the future, new firm thermal generating units that are quick-starting, fast ramping, cycling, and peaking type are preferred. In the Preferred Plan, a mix of combustion turbines, internal combustion engines, and combined cycle units are included that meet these criteria. This mix of new flexible generation, in combination with energy storage and demand response, will minimize baseload generation and accommodate unprecedented levels of variable renewable generation.

The Preferred Plan also includes the addition of 50 MW of wind and 50 MW of utility-scale solar PV in 2020. This amounts to more than 1,000 MW of solar (including DG-PV) and 175 MW of wind by 2030. Despite this unprecedented level of variable renewable energy on a small island grid, the reliability models have confirmed that the electric system would be operable and survive major transient events (for example, major transmission line faults and sudden trips of large generators). The successful integration of the variable renewable energy is due, in parts, to the flexible thermal generating units that complement the renewable resources and the judicious utilization of energy storage and demand response programs.

Procurement of Replacement/New Generation

The PSIPs for Oʻahu and Maui identify replacement generation being needed in 2022 and 2019, respectively. In addition, demand response programs and ESS that are expected to provide capacity reserves for both island power systems will implemented in the immediate future. The most urgent replacement generation is needed for the island of Maui, as it would support the timely retirement of the four generating units at Kahului Power Plant by 2019. Below is a recommended process for competitively procuring the needed replacement generation for the Maui power system. A similar process is recommended for Oʻahu.

Maui Electric – Maui Island

The PSIP for Maui island includes procurement of replacement/new firm generation resources in advance of the retirement of 36 MW and 4 MW of capacity at Kahului Power Plant and HC&S Power Purchase Agreement (PPA) termination, respectively, on or before 2019. The PSIP also indicates a need to locate a portion of the replacement/new generation in the South Maui Area in order to mitigate an under-voltage contingency without building new overhead transmission lines in the area. Subject to the Commission's concurrence, the following competitive process (not a waiver to the competitive bidding framework) will be implemented in the immediate future to procure the needed replacement/new generation.

1. Maui Electric will implement Demand Response programs in accordance with the *Integrated Demand Response Portfolio Plan* (IDRPP) to secure demand response (DR) capacity reserve on Maui island.
2. A technical specification will be prepared that describes the situation on Maui island, including the need for replacement generation for the retirement of KPP and termination of the PPA with HC&S. The specification will also describe the need for non-transmission alternatives (NTA) to new overhead transmission in the South Maui area, and how new generation and/or energy storage may be implemented to address the under-voltage contingency that exists.
3. The technical specification will describe the size, type, locations and timing of resources that may be proposed for implementation to meet the specified needs. Alternative resources and resource configurations that would meet the need would be invited to be proposed and will be given full consideration.
4. The technical specification would not provide target capacity for individual generating units or in total, but would likely specify minimum capacity size for individual units and capacities, and a maximum size for individual units (to meet system security and system operation and dispatch requirements).
5. At the Commission's direction, Maui Electric or an independent third party will run a competitive procurement process, including the issuance of a Request for Proposals (RFP) that utilizes the technical specification.
6. In parallel with Step 5, if requested by the Commission, Maui Electric would run a competitive process for the selecting and contracting of an Independent Observer (IO).
7. In parallel with Step 5, Maui Electric would run a competitive process for the selection and procurement of energy storage systems (based on the needs defined by the PSIP).

8. Maui Electric will prepare a "self-build option" for replacement/new generation in accordance with the technical specification described in Steps 2 and 3.
9. Maui Electric (or the third party designated by the Commission), in cooperation with the IO (if the Commission requested an IO) would evaluate the proposals received in response to the RFP issued in Step 5. The evaluation of proposals will be based, in parts, on the needs for the Maui island power system taking into account the results to procure energy storage and DR capacity reserves in Steps 7 and 8, respectively.
10. The results of the evaluation of the competitive proposals and the Maui Electric self build option would be submitted to Commission, with an accompanying recommendation by the IO (if the Commission requested an IO) on the selection of projects. The recommendation to the Commission would include a portfolio of energy storage, DR, and generation resources that meet the power system's needs as defined by Adequacy of Supply analyses and PSIP.
11. Pending approval by the Commission on the path forward, applications for approval of specific projects and/or power purchase agreements will be prepared and submitted to the Commission for approval. If approved, the projects and/or PPA would be implemented.

Hawaiian Electric – O'ahu

A similar process would be implemented to provide replacement/new generation in 2022, and/or extension of PPAs that will retire in 2022. Subject to the Commission's concurrence, the competitive process (not a waiver to the competitive bidding framework) would be implemented starting in early 2015.

Utilization of Renewable Energy

As shown graphically in Figure 5-9 below, exceptionally high levels of variable renewable energy can be utilized (that is, not curtailed) throughout the planning period. From 2015 through 2030, 97.3% to 100% of the estimated energy produced from all variable renewable resources would be utilized each year. This would be accomplished by increasing the operational flexibility of existing steam generating units (that is, converting from baseload to cycling, improving turndown, and enhancing ramp rates), acquiring new flexible firm thermal generation as the existing steam generators are planned for retirement, and using energy storage and demand response programs.

It should also be noted that the utilization is greater than 99% for every year except the last three in the planing period (that is, 2028 to 2030), but it is still greater than 97% even in this period. The reason that this is forecast to occur is that energy efficiency is forecast to grow exponentially during the end of the planning period. Excess energy conditions would be more significant should this happen. Conversely, if there is slight load growth, for example due to higher adoption rates of electric vehicles, the execss energy condition would not exist and utilization of energy produced from variable renewable energy resources would remain close to 100%.

Total System Variable Renewable Energy for O'ahu

% RE Utilized	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2015-2030
	99.9%	100.0%	99.9%	99.9%	99.9%	99.9%	99.9%	99.9%	99.9%	99.8%	99.8%	99.8%	99.4%	98.9%	98.1%	97.3%	99.4%

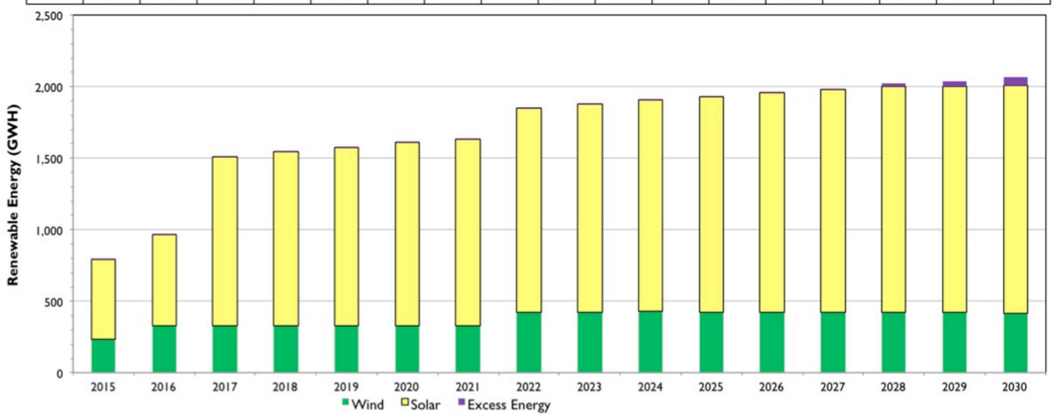

Figure 5-9. Total System Variable Renewable Energy Utilized

The overall utilization of energy from all renewable energy generation resources (variable and firm) is forecast to be even higher with the Preferred Plan. It would be greater than 99% in every year except 2029 and 2030, when it would be greater than 98% (Figure 5-10).

Total System Renewable Energy for Oahu

% RE Utilized	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2015-2030
	99.9%	100.0%	99.9%	99.9%	99.9%	99.9%	99.9%	99.9%	99.9%	99.9%	99.9%	99.9%	99.7%	99.3%	98.9%	98.4%	99.6%

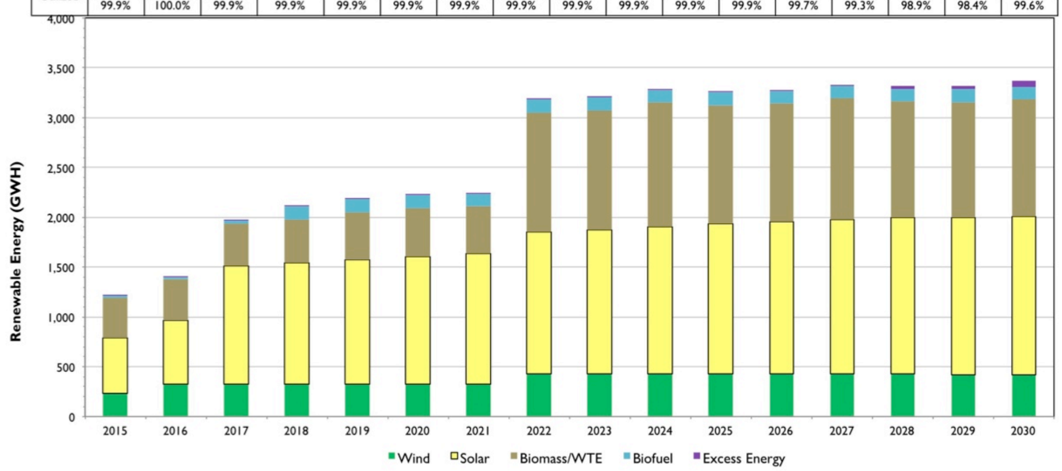

Figure 5-10. Total System Renewable Energy Utilized

ENERGY STORAGE PLAN

Integrating energy storage is key to adding increased amounts of both distributed and utility-scale renewable generation into our power supply mix.

Energy storage provides unique operational and technical capabilities, including the ability to provide essential grid services. In addition, energy storage can be part of a portfolio of potential resources that can increase grid flexibility, operability, and reliability in a rapidly changing operating environment.

The Companies will evaluate and implement energy storage technologies and applications from two perspectives:

1. **Utility Perspective:** Evaluate energy storage in parallel with other resource options, such as new types of generation, modified operations of existing generating units, advanced planning and operational tools, smart grid and micro-grid technologies, and demand response programs.
2. **Customer Perspective:** Explore ways to utilize energy storage to provide a broader range of services for customers, including the utilization of energy storage within micro-grid environments, demand response, and thermal storage (for example, grid interactive water heating and ice storage). This perspective also includes the need to incorporate customer-owned energy storage as a grid resource, including possible ownership and operation of behind-the-meter energy storage assets.

The Strategic Energy Storage Plan (Energy Storage Plan) applies to all three operating Companies; however, due to differences in generation portfolios and operational needs, the action plans and timeframes for Hawaiian Electric, Hawaiʻi Electric Light, and Maui Electric are expected to be different.

Appendix J – Energy Storage for Grid Applications, provides background information regarding the commercial status of energy storage, applications for energy storage, grid energy storage technologies, and the economics of energy storage, including capital and operating cost assumptions utilized in the PSIP.

Goals and Objectives of the Energy Storage Plan

The primary goal of the Companies’ Energy Storage Plan is to utilize energy storage in cost-effective applications that enhance grid services to accomplish three outcomes:

- Optimize the costs of power system operation;
- Maintain acceptable reliability and security of the power system; and
- Expanded services to customers.

The following objectives will be pursued to achieve the Companies' strategic goal:

- Pursue utility-owned and -operated energy storage projects under applications that make technical and financial sense, but at the same time, be open to non-utility storage options.
- Develop utility-owned and -operated distributed energy storage solutions and collaborate with industry and customers to utilize customer-sited storage as grid assets.
- Explore and pursue actions that address business model, utility cost recovery, customer rate schedules for different services, and regulatory issues that affect the Companies' ability to implement energy storage.
- Foster innovation and build internal operating experience through energy storage research and development activities.

The Companies are willing to consider multiple mechanisms in support of achieving the goal of developing a resource portfolio enabling lower costs and reliable power for our customers.

Guiding Principles of the Energy Storage Plan

The following guiding principles will govern the implementation of the Companies' Energy Storage Plan.

Implement energy storage under a programmatic approach with a broad portfolio of assets consisting of both utility-scale and customer-sited systems. Assess and implement an energy storage program for the deployment and operation of energy storage assets such that reliability, public policy, and customer interests.

Own and operate energy storage assets only when in the best interest of customers. When energy storage is shown to be a viable alternative, the Companies' preference will be to own and operate energy storage systems. However, various business and ownership models, as well as service contracting arrangements, will be considered to best meet the Companies' strategic goals objectives and customer needs.

Pursue energy storage to broaden the level of services for customers. The Companies will evaluate energy storage applications at the distribution level that increase customer value, including the contributions of customer-sited energy storage systems. The Companies are also open to owning energy storage systems on the customer-side of the meter to provide services to its customers. An example is the use of distributed, community-based and/or customer-sited storage to perform bulk load shifting. Another potential application of customer-sited energy storage is the use of EV batteries as energy storage for grid management purposes (Grid to Vehicle (G2V) and Vehicle to Grid (V2G) applications).

Balance system security with public policy-based renewable energy goals. The planning and implementation of energy storage is, in part, driven by system security and reliability requirements as additional amounts of variable renewable energy generation drive the need for additional grid services.

Pursue cost-effective energy storage by balancing cost with system reliability. The costs to implement energy storage systems will be a factor in project development decisions as financial impacts to customers must be considered when integrating renewable energy resources. Therefore, it is critical that business decisions be based on best-available pricing intelligence (current and future), and a clear understanding of the cost benefits that the energy storage asset can provide to the system.

The timing of the Companies' plans to deploy energy storage and enter into contracts for services will consider technology maturity and development, pricing trends, and development lead times. When determining the timing of energy storage system installation, the Companies must consider technology development and pricing trends and the estimated timelines required to design, permit, and construction such facilities. As discussed earlier, it is anticipated that some energy storage technologies will require considerable project development time.

Control of energy storage systems will be coordinated with other resources on the system through the Companies' Energy Management Systems (EMS). Any energy storage system providing system-level services, such as frequency regulation or response, must be coordinated with other resources on the grid; the system operator may accomplish this through the storage asset's local frequency response settings or through actual control of the energy storage asset. Although control will be centralized at the Companies' System Operation Control Center, distributed storage systems may be aggregated through a third party or through the Company's EMS or Advanced Distribution Management System (ADMS). Also, since energy storage systems are finite energy resources, their operation must be transitioned to appropriate generation sources in a coordinated and controlled manner so that other resources can be made available when the storage is depleted. It is essential that any resource that is integral to system operations, including energy storage, be monitored at the system control center.

Energy storage will be considered in generation and transmission and distribution planning analyses to assess alternatives to generation and T&D projects. Planning for generation, transmission, and distribution assets and applications will include energy storage (and load management). A balanced portfolio of resources will be pursued during utility planning.

Collaborate with stakeholders and leverage external resources when available. The Companies will seek collaborative opportunities for energy storage solution development, especially on the customer side of the meter. External participation in energy storage solutions should be considered where it makes operational and financial sense. To offset technical and financial risks of unproven technologies or applications within a nascent energy storage industry, the Companies will seek opportunities for collaboration with external entities to leverage labor, expertise, and funding.

Energy Storage Operating Philosophy

The implementation plans for energy storage must be developed in concert with modified operating practices such as generation unit dispatch, load shed schemes, load management, and customer-focused solutions. By executing the energy storage strategy, the Companies will strive to:

- Ensure the Safety of the Company's crews and contractors working on either energized or non-energized distribution lines[33];
- Maintain or improve system reliability, and provide acceptable system reliability which is security through normal operation conditions and disturbances;
- Increase the value of electric services and lower cost to customers; and
- Develop a diverse portfolio of resources to reduce dependence on imported fossil fuels.

Energy Storage Operating Issues

Existing and growing levels of variable renewable energy resources, primarily wind farms and distributed PV, are creating the need for additional grid services. In the PSIP, Appendix E provides a description of essential grid services, and Chapter 4 provides a description of security analysis for increasing levels of distributed PV and new resources.

System impacts of the aggregate contribution of variable generation affect various time frames. These time frames determine the particular grid services that are required to mitigate these impacts.

[33] The Companies will implement additional safety procedures to protect the safety of line crews, including design and installation of appropriate breakers and switching to ensure that energy storage will not inadvertently energize lines when our crews are performing repairs and maintenance.

Sub-Seconds to Seconds (primary frequency response time frame)

These impacts increase the need for frequency-responsive contingency reserves and regulating reserves:

- Fast ramping events (ramping of renewable resources exceeds ramping of dispatchable generation and primary frequency response for generation with governor response)
- Increased second-to-second frequency variation due to fast variability
- Increased rate-of-change of frequency during faults and contingencies
- Larger frequency impacts from faults and contingencies (lower frequency nadir result in increased under-frequency load shedding)

Seconds to Minutes (supplemental frequency response and regulation time frame)

These impacts increase the need for regulating reserves and offline quick-start reserves (10-minute, 30-minute reserves):

- Increased need for second-to-second system balancing due to changes in variable generation output
- Sustained ramp events resulting in significant loss in wind or PV production to the system

Minutes to Hours

These impacts increase the need for offline reserves and require flexible options to balance supply and demand:

- Less predictability in the net demand to be served by generation
- Increased flexibility required from resources due to change in the nature of the demand served (that is, morning and evening peaks with low daytime and night time demand)

Energy Storage Uses in the Companies' Systems

Chapter 4 of the PSIP describes system security analysis that identified ancillary services for the existing and future possible system resource combinations. These services can be provided by storage. Detailed operational requirements are provided in PSIP Appendix E: Essential Grid Services. To adapt to the changing power grids, energy storage will be evaluated for its technical and cost effectiveness in providing the following applications/grid services.

Frequency Responsive Contingency Reserve

Application

- Respond very quickly to a change in frequency, to arrest frequency decay and mitigate under-frequency load shedding (UFLS)
- Provide sufficient energy capacity (MWh) during recovery period to provide time for operators to turn on units that cover generation deficit until combustion turbines can be started

Storage System Characteristic

- Fast response: Detect and respond within the first few cycles of sudden change in frequency
- High MW rating: Exact size is dependent on desired results
- Minimum MWh rating: Equal to MW rating times the amount of time needed to implement replacement reserves
- Must be constantly charged to a specific level
- Must have the appropriate safety features to prevent energizing during periods when not required (that is, when workers are working on a de-energized portion of the line, or must be able to trip off due to a maintenance situation where a worker may be in the line)

Regulating Reserve

Application

- Dampen momentary frequency variations through governor-droop type response (if frequency responsive, this is required for a portion of the regulating reserve)
- Respond to AGC signals to increase or decrease output to regulate system frequency

Storage System Characteristics

- Governor-droop-like response to changes in system frequency (for frequency responsive regulating reserve)
- MW rating dependent on desired up/down regulation amount
- Control interface to AGC, responds within one AGC cycle
- Frequent charge/discharge cycle (may be every AGC cycle, 4–6 seconds)
- Must maintain energy for long enough for supplemental reserves to be brought online
- Must have the appropriate safety features to prevent energizing during periods when not required (that is, when workers are working on a de-energized portion of the line, or must be able to trip off due to a maintenance situation where a worker may be in the line)

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Load/Peak Shifting – System Ramping, Curtailment of Renewables, Economic Benefits

Application

- Absorb energy (charge) during periods of excess energy to minimize curtailment of variable renewables and optimize use of more efficient generation resources
- Provide power (discharge) during periods where there is demand for the energy

Storage System Characteristics

- MW rating dependent on desired deficit compensation
- High MWh rating (multiple hours) driven by amounts and duration of excess energy
- Must have the appropriate safety features to prevent energizing during periods when not required (that is, when workers are working on a de-energized portion of the line, or must be able to trip off due to a maintenance situation where a worker may be in the line)

Voltage Support – System Stability and Security

Application

- Provide dynamic VARs to regulate voltage (site specific)
- May be used to replace dynamic voltage support from generation resources, allowing them to be taken offline

Storage System Characteristics

- MVAR dependent on need
- Site-specific: MVAR support must be at location needed
- Fast-responding, dynamic, at a droop setting determined by specific requirement
- Discharge duration and minimum cycles per year not relevant for this use
- Must have the appropriate safety features to prevent energizing during periods when not required (that is, when workers are working on a de-energized portion of the line, or must be able to trip off due to a maintenance situation where a worker may be in the line)

Black Start

Application

- Provide power that can be used for system restoration following system failure
- Used as an energy source to provide station power to bring power plants online and re-energize transmission and distribution lines following grid failure

Storage System Characteristics

- Able to self-start without grid power
- Able to be controlled remotely by the system operator
- MW rating able to provide startup energy to major generation resources, and absorb transformer inrush currents
- Must maintain enough charge after grid failure to provide system restoration services
- Must have capability to regulate voltage and frequency
- Must have the appropriate safety features to prevent energizing during periods when not required (that is, when workers are working on a de-energized portion of the line, or must be able to trip off due to a maintenance situation where a worker may be in the line)

Incorporating Energy Storage and Unit Commitment/Dispatch

Properly designed energy storage can provide the system operator with a flexible resource capable of providing capacity and ancillary services. In order to provide the system operator with appropriate control and visibility of energy storage, storage assets will be equipped with essentially the same telemetry and controls necessary to operate generating units. The specific interface requirements depend upon whether the storage device is responding automatically, or is under the control of the system operator. For devices that are integrated to the system control center, telemetry requirements include:

- Real-time telemetry indicating charging state, amount of energy being produced, and device status.
- Control interface to the operations control center to control the storage charging and discharging of energy.

Depending on the specific application, storage may also be required to respond to local signals. For example, storage may need the capability to respond to a system frequency change in a manner similar to generator governor droop response, which may be used for a contingency reserve response or for frequency responsive regulating reserve. Another example of local response includes the ability of the storage to change output (or absorb energy) in response to another input signal from a variable renewable energy resource in order to provide "smoothing" of the renewable resource output.

A special consideration of short-duration storage is the fact that it is a limited energy resource. This introduces the need for the system operator to be informed regarding the storage asset's charging state, and the need to ensure that the integration and operation of these resources allows for replacement energy sources prior to depletion of the storage. This replacement could be in the form of longer-term storage or generation resources.

Incorporating energy storage into daily unit commitment and generator dispatch is dependent on how the storage is to be used.

Storage Used for Regulating Reserves: When used to provide regulating reserves, the energy storage will be committed and dispatched like any other resource used to provide regulating reserves via AGC commands. The storage would contribute to available reserves. In order to emulate the response of a generator, the storage will be equipped with frequency-response (droop) capabilities. The interface must provide enough information so the operator may bring online replacement reserves if the storage is depleted.

Storage Used for Frequency Responsive Contingency Reserves: When used to provide frequency responsive contingency reserves, the storage asset must be operating on the power system as a security requirement. This storage stands ready to respond to short-term events and should not be deployed for regulation. The availability of storage for contingency reserves may reduce the number of online units required for system security and can be used to improve the response of the system to loss of generation events or similar disturbances that require an automatic response. It is important that the storage provides for sufficient energy duration so that replacement energy sources can come online before the storage is depleted.

Storage Used to Provide Capacity: If the storage is used to provide capacity to serve load, then it will be treated like a generator and will be committed and dispatched in the same manner as a generator, based on marginal costs. However, because the energy storage resource will be limited in terms of how long it can provide capacity to the system, additional status monitoring capabilities will be required to ensure that the energy storage device is utilized in a manner consistent with its capabilities (for example, depth of discharge). This will also require that the daily unit commitment be performed to take into account the limits on duration of capacity available from the storage asset.

Customer-Side Energy Storage

The PSIPs did not specifically utilize customer-side energy storage devices. However, customer-side energy storage might be aggregated to achieve the same operational attributes as utility-scale energy storage. The aggregated storage concept allows storage assets to be properly sized and installed to meet bulk power supply needs and to help customers manage their electricity use. In order for distributed energy storage to be of value in bulk power applications, the following considerations must be taken into account.

Distributed energy storage can smooth the output of distributed solar PV. Under the existing net energy metering rules, however, there is very little incentive for a customer to install their own energy storage device because customers essentially utilize the grid as a storage system. If the NEM arrangement is modified or eliminated and replaced with an arrangement that compensates customers based on a price that is more in line with the Company's marginal cost of generating energy for the system, then customers will have specific price signals that they can use to evaluate the benefits of installing their own storage.

Distributed energy storage may be useful through aggregation programs. Storage sited at customer facilities can not only play an active role in balancing load for the customer's site, but if aggregated, multiple customers' storage systems can provide a tool for providing grid services. Proper design of distributed storage programs will require additional investigation. However, the overhaul and expansion of time-based pricing programs that are part of the Companies' *Integrated Demand Response Portfolio Plan*[34] (IDRPP), and the concept of third-party aggregator programs provide opportunities to utilize aggregated energy storage for providing grid services.

Distributed energy storage will likely cost more than grid scale storage, however, it may be possible for distributed energy storage systems to be implemented faster than grid-scale systems. Due to economies of scale inherent in utility-scale storage applications, customer-side energy storage is expected to have a higher capital cost on a per unit of storage capacity installed. Even as battery costs decline, this cost disadvantage relative to grid scale storage will remain since the balance of plant components is expected to be higher per unit of capacity for distributed storage. While it is assumed that any customer-side energy storage project would be paid for by the customer, the compensation that can be paid by the Companies to customers for customer-side energy storage must reflect the cost of alternatives available to the Companies; otherwise excess costs will be borne by ratepayers. The value proposition for the customer is being evaluated through an active initiative with storage technology providers.

In order to provide certain grid services, distributed energy storage must be equipped with proper telemetry / communications to allow coordination with grid operations; the telemetry / communications design must provide for operation within specified performance time frames. Advances in communications utilizing Internet protocols (IP)

[34] See *Integrated Demand Response Portfolio Plan*. Hawaiian Electric Companies. Docket No.2007-0134. July 28, 2014.

and cloud-based aggregation technologies are now more prevalent in the industry. With the addition at the distributed storage site of control hardware with communication backhaul to an aggregator/coordination point for the utility, near real-time storage asset status and the ability to control the storage asset can be provided for customer–sited storage. For essential grid services response, an aggregated response would be needed to manage local distribution conditions as well as provide some of the support services to manage ramping of locally sited distributed PV. The response time is a function of both communications latency and the ability of a distributed resource itself to respond in the time frames required by certain grid services. These response times are described in Appendix E, Essential Grid Services. For example, regulating reserves must be immediately responsive to AGC (observable change within 2 seconds) signals, which requires an interface to the Energy Management System (EMS). Distributed energy storage used to provide grid services with fast response requirements and integration with the EMS must also be equipped with the proper telemetry and communications infrastructure. Depending on the business model, the cost of the communications infrastructure is in addition to the cost of the storage product. This cost may be incurred by the customer, or by aggregators who manage the telemetry devices. The cost/benefit must consider the interface costs and value benefit for the customer and utility. Without coordination and visibility by the utility, the value of customer-sited storage is diminished.

The Companies are engaged in conversations with customer storage integrators and suppliers to develop and test advanced integration and management features for customer-sited energy storage systems.

Energy Storage in the Preferred Plan

The Preferred Plans for the three operating companies include specific energy storage additions summarized below. These are additions on top of energy storage already installed in the respective systems, and could change as the Companies conduct further technical and economic analyses. Table 5-6 through Table 5-8 show the energy storage additions that are in the Preferred Plan (demonstration projects are not shown).

Year Installed	Capacity	Type of Storage Device	Storage Duration	Purpose
2017	200 MW	Battery (advanced lead-acid or lithium ion) or Flywheel	20 min	Contingency reserves to bring O'ahu system into compliance with security criteria
2022	100 MW	Battery (advanced lead-acid or lithium ion) or Flywheel	30 min	Regulation

Table 5-6. Hawaiian Electric Preferred Plan Energy Storage Additions

Year Installed	Capacity	Type of Storage Device	Storage Duration	Purpose
2015 (Maui)	2 MW (committed project)	Battery	11 min	Frequency regulation; DG-PV support
2018 (Lana'i)	10 MW	Battery	90 min	Contingency reserves; DG-PV support
2018 (Moloka'i)	10 MW	Battery	90 min	Contingency reserves;
2019 (Maui)	20 MW	Battery	30 min	Regulating reserves; reduce regulating reserves carried by thermal units
2019 (Maui)	20 MW	Battery	30 min	Contingency reserves. Bridge until quick start RICE units can be installed for voltage support in South Maui

Table 5-7. Maui Electric Preferred Plan Energy Storage Additions

Year Installed	Capacity	Type of Storage Device	Storage Duration	Purpose
2017	5 MW	Battery (advanced lead-acid or lithium ion)	30 min	Managing variable generation ramping events
2017	20 MW	Battery (advanced lead-acid or lithium ion)	20 min	Contingency reserves

Table 5-8. Hawai'i Electric Light Preferred Plan Energy Storage Additions

Hawaiian Electric Energy Storage RFP (O'ahu)

On April 30, 2014, Hawaiian Electric issued an RFP for energy storage. The RFP requested proposals that encompass engineering, procurement, construction, testing, commissioning, start-up, and performance verification from 60 MW up to 200 MW for a storage duration of 30 minutes to the grid (the Project). (The Project could consist of multiple energy storage systems installed at multiple locations on the grid.) As previously discussed herein, storage durations up to 30 minutes are useful for the provision of ancillary services, and the capital cost of storage may be more attractive than building a new generator, provided that the storage system can respond within the time frames required for ancillary services.

Interested bidders were requested to submit proposals describing sizing, storage technologies, and operational capabilities of their energy storage system. Bidders were encouraged to propose projects on a number and size that optimizes their technology for Hawaiian Electric's system needs.

The overall objectives of the Project are to incorporate into the energy storage system as many of the functions below as practical and cost effective:

- Provide an additional resource to help manage system frequency by absorbing or discharging energy on a minute-to-minute basis to help maintain system frequency at 60 Hz.
- Provide energy for a short duration during the recovery period after a sudden loss of generation until a quick starting generator can be brought online.
- Provide an immediate injection of a large amount of energy for a short duration in the event of a sudden loss of generation to decrease the need to utilize load-shedding blocks.
- Assist Hawaiian Electric's generation fleet with meeting system load variations due to intermittency of renewable generation caused by unpredictable wind or sun availability.
- Provide Hawaiian Electric with grid operational flexibility to reasonably manage distributed, intermittent generation with the island electrical load.

Bidders were encouraged to propose the best technology solution to meet the Companies' technical and operating needs. The RFP explicitly asked for proposals that might utilize any of the following technologies:

- Battery energy storage
- Mechanical flywheel energy storage
- Capacitor energy storage
- Compressed gas (for example, air) energy storage
- Pumped storage hydroelectric
- Any combination of the above

Proposals were received on July 21, 2014. The proposals are currently under review and in order to protect the integrity of the RFP process cannot be discussed here in detail. However, generally the proposals received included lead-acid batteries, several forms of lithium-ion batteries, flow batteries, pumped-storage hydroelectric, and mechanical flywheels. Pricing proposals are generally consistent with the PSIP assumptions detailed above.

Hawaiian Electric intends to evaluate these proposals, and if cost and technical requirements are met, make an award on or about August 29, 2014.

Utilization of Energy Storage on O‘ahu

Companies already have energy storage technologies and application evaluation programs in place. These include the following field demonstration projects:

- Hawaiian Electric is collaborating with Hawai‘i Natural Energy Institute (HNEI) of the University of Hawai‘i to test the ability of a one MW/250 kWh fast-response lithium-titanate battery (purchased by the University of Hawai‘i with a federal grant) to help smooth power fluctuations and regulate voltage on a feeder with high distributed PV penetration on O‘ahu. The battery energy storage system (BESS) will be operated to evaluate circuit-level functions, such as power smoothing and voltage regulation, and system-level frequency response to assess whether this technology is feasible and to provide Hawaiian Electric with operational experience with distributed energy storage technology. Installation is targeted for late 2014.
- Hawaiian Electric is collaborating with STEM to deploy and demonstrate the aggregated dispatch and response capabilities of distributed energy storage systems in commercial and industrial load management applications. These storage assets will be coordinated with utility operations to help manage high penetration PV conditions. This program will provide valuable information regarding the installation and use of new telemetry devices, and will provide operational and customer experience with aggregated storage resources. The lessons learned from this program will be used to help design effective aggregator programs. This effort leverages the funding provided to STEM by the State’s Energy Excelerator Program. Installation is targeted for late 2014 through early 2015.

The Companies will continue their energy storage demonstration projects of substation-sited and other distributed applications to build its experience base of technical and cost characteristics. These efforts will continue in parallel to commercial applications that are implemented to meet critical operational needs.

Utilization of Energy Storage on Maui and Lana‘i

To varying degrees, existing battery energy storage systems on Maui and Lana‘i have the potential to be repurposed to better serve the needs of the entire electrical system. In fact, one of the third-party owned existing batteries on Maui is already used to provide frequency regulation. Given their size in relation to their respective grids, it may be possible to utilize the other battery energy storage system on Maui, and the third-party owned battery energy storage system on Lana‘i, for frequency regulation as well. However, in cases where the battery energy storage system is not owned by Maui Electric, the ability to repurpose the energy storage system will be contingent on negotiations of contract terms between the utility and each owner. Amendments to current contract terms would be as agreed upon by the parties and approved by the Commission.

Existing Storage at Maui Electric

The Maui system currently contains two battery energy storage systems that are owned and operated by third parties. The Kaheawa Wind Power II, LLC (KWP2) facility couples a 21 MW wind farm with a 10 MW/20 MWh battery energy storage system. The KWP2 battery provides system support in the form of frequency regulation and regulating reserve. In addition, the KWP2 BESS provides ramp rate control of its wind power output to meet ramp rate limits required by the Power Purchase Agreement (PPA).

The Auwahi Wind Energy, LLC (AWE) facility couples a 21 MW wind farm with an 11 MW/4.4 MWh battery energy storage system; the AWE battery was installed to allow the facility to meet the performance standards of their PPA, primarily ramp rate control.

In addition, Maui Electric owns and operates a 1 MW/1 MWh battery energy storage system located at the Wailea substation as part of the Department of Energy (DOE)-funded, HNEI-led Maui Smart Grid project. The Maui Smart Grid project battery provides peak circuit load reduction and voltage support. Operation of this battery is expected to continue through 2018. Several other smaller batteries are located across Maui as part of different research efforts, including the JUMPSmart project.

Several smaller batteries are targeted for installation on Maui as part of the Japan U.S. Maui Smart Grid Project (JUMPSmart). This project, in collaboration with Maui Electric, Hitachi, Hitachi Advanced Clean Energy Corporation, and the New Energy and Industrial Technology Development Organization in Japan (NEDO), will evaluate the aggregation and management of distributed energy storage and other distributed resources through smart grid technology.

Existing Energy Storage on Lana‘i

On Lana‘i, the Lana‘i Sustainability Research, LLC (LSR) 1.2 MW photovoltaic facility incorporates a 1.125 MW/500 kWh battery energy storage system within their generation facility design. Similar to the AWE battery, the LSR battery is utilized to allow the facility to meet the performance standards in their PPA, primarily ramp rate control.

Planned Energy Storage on Moloka‘i

Maui Electric, in collaboration with HNEI, is currently pursuing a 2 MW/375 kWh battery energy storage project on the island of Moloka‘i to provide frequency regulation and PV integration support. Technical assessments on the optimal use of the battery are currently underway. Although a project schedule has not yet been developed, installation of the BESS is anticipated to occur in 2015.

Utilization of Energy Storage on Hawai‘i

Hawai‘i Electric Light on Hawai‘i Island is collaborating with HNEI to test the ability of a 1 MW/250 kWh fast-response lithium-titanate battery to smooth the output of the Hawi Renewable Development wind farm. The battery was purchased by HNEI with a federal grant. The BESS was commissioned in December 2012, and continues to be operated for evaluation.

Hawai‘i Electric Light has installed 100 kW/248 kWh lithium ion batteries at two customer-owned PV projects on Hawai‘i Island using US DOE stimulus funds awarded through the State of Hawai‘i Department of Business, Economic Development, and Tourism (DBEDT). These BESS projects, installed in July 2012, are helping Hawai‘i Electric Light Company evaluate the battery’s ability to smooth fluctuations of commercial-scale PV projects.

TRANSMISSION AND DISTRIBUTION SYSTEM DESIGN

Transmission

The role of the transmission systems for the Hawaiian Electric Companies remains the same—that is to transmit bulk power from one point to another in a networked configuration at current transmission voltages.

While the role of the transmission system on O‘ahu remains the same, changes in its design have been identified as part of the PSIP. Specifically, the Hawaiian Electric PSIP identifies the expansion of the O‘ahu 138 kV transmission system through a transmission loop from the central area to the northern area of the island. Currently, O‘ahu’s 138 kV transmission system is limited to the leeward, central and southern portions of the island. Yet, there has been much interest and demand for interconnection of utility-scale and distributed renewables from the northern and central areas of the island. A new transmission loop can interconnect renewable generation from this part of the island beyond the capacity of existing subtransmission circuits in the area in-line with the Preferred Resource Plan for O‘ahu.

Similarly, the role of the transmission system on Maui remains the same. However, the PSIP identifies the addition of a new 69 kV transmission line between substations in Wailuku and Kahului in order to provide greater voltage regulation of the 23 kV system in Central Maui, defer overloads of 69-23 kV transformers, and allow for the retirement of all generators of Kahului Power Plant as identified in the Maui Electric PSIP for 2019.

On the island of Hawai‘i, the role and the design of the transmission system remains the same. However, if additional generation is built on the East side of the island beyond what is included in the Hawai‘i Electric Light PSIP (such as an additional increase in geothermal generation), the design of Hawai‘i Island’s transmission system would require additional transmission capacity to reliably transmit bulk generation from the east side to the west side of the island.

Distribution

In contrast to the transmission system, the role of the distribution systems does change dramatically as part of each Company’s preferred resource plans. The previous role of distribution system was to serve local power loads only. As part of the PSIP and DGIP, the distribution system will continue in its role to serve in the role of serving local loads, but now will also have an additional role of collecting and reliably delivering DG power and energy up to the sub-transmission or transmission systems. This is necessary in order to accommodate approximately 600 MW, 120 MW, and 120 MW of DG-PV on O‘ahu, Maui, and Hawai‘i islands, respectively.

As detailed in the Companies’ DGIP report, the Hawaiian Electric Companies plan to continue to use a radial architecture for the distribution system as a more cost-effective alternative compared with building a new networked distribution system. But in order to fulfill its new role to collect and reliably deliver DG power up with a radial architecture, the design of the distribution will need to be modified by: 1) upgrading circuit components such as replacing LTCs with newer designs capable of regulating voltage in two directions; 2) adding new circuit components, such as the addition of grounding transformers to address ground fault over-voltage events, to ensure operating conditions on all circuits remain within expected and allowable limits; and 3) adding intelligence and controls throughout the distribution circuit and substation along with two-way communications to monitor and control inverter operation, switching, regulation of voltages and management of power flows on distribution feeders.

It should be noted that as part of design of the transmission and distribution (T&D) system over the planning period, the Company’s telecommunications system will play an increasingly important role in the operation of the T&D system. In fact, one should think of the transmission and distribution system evolving into a transmission, distribution, and communications system design. This communications system is not only an essential part of the Company’s Smart Grid Program, it is an essential part of the Companies’ plan to modify and upgrade its distribution system to allow for the integration of greater levels of DG, as well as to allow for the interoperations between utility’s grid systems with customer-side equipment such as advanced inverters, storage devices, and control systems.

Such design changes for the distribution system are common to all Hawaiian Electric Companies and they are discussed in detailed in our DGIP.

In order for the transmission and distribution system to reliably operate in its various roles through the planning period of the PSIPs, the Hawaiian Electric Companies must intelligently integrate its Smart Grid and DGIP upgrades with its Asset Management programs. All components of a circuit (such as conductors, wires, breakers, switchgear, transformers, poles, and others) must be replaced on a programmatic basis in an asset management program to ensure that the transmission and distribution system remains reliable and able to serve in its increasingly important role in the grid. However, such replacement and upgrades much be done not just for age or condition reasons, but to also be done to add the control and communications functionality described in the Smart Grid plan and DGIP. By integrating plans for Smart Grid and DGIP with the Asset Management programs, savings and efficiencies can be achieved as grid components are replaced and upgraded.

EXISTING SITE ANALYSIS

As new firm generating units are required to replace retiring generating units, there are opportunities and considerations of siting new flexible firm generating units at Hawaiian Electric's existing generating stations (that is, Kahe, Waiau, and Campbell Industrial Park).

When considering where to locate firm generating units, the following items need to be evaluated:

- Physical space
- Tsunami protection
- Permitability (for example, air permit, SMA permit, water use permit)
- Proximity to substations and transmission lines
- Water supply logistics
- Fuel supply logistics
- Wastewater and sewer logistics

The sections below discuss all but the last item as they specifically relate to the Kahe Power Plant, Waiau Power Plant, and Campbell Industrial Park (CIP) Generating Station[35]. The discussion only presents what may be possible at each location, but does not evaluate the costs or relative merits of the options presented. That said, it is clear that substantial amounts of replacement generation could be located at Hawaiian Electric's

[35] The wastewater/sewer logistics are not discussed since each of the existing generating stations have full systems in place that are sufficient to cover future needs.

existing generating stations and that infrastructure in place for fuel storage, grid interconnection, and other purposes would likely result in lower project costs than siting new generation at "green-field" sites.

Physical Space and Tsunami Protection

Kahe Power Plant

There currently exists open space of approximately 1.8 acres at the Kahe Power Plant adjacent to Kahe Units 5 & 6 (shown in Figure 5-11).

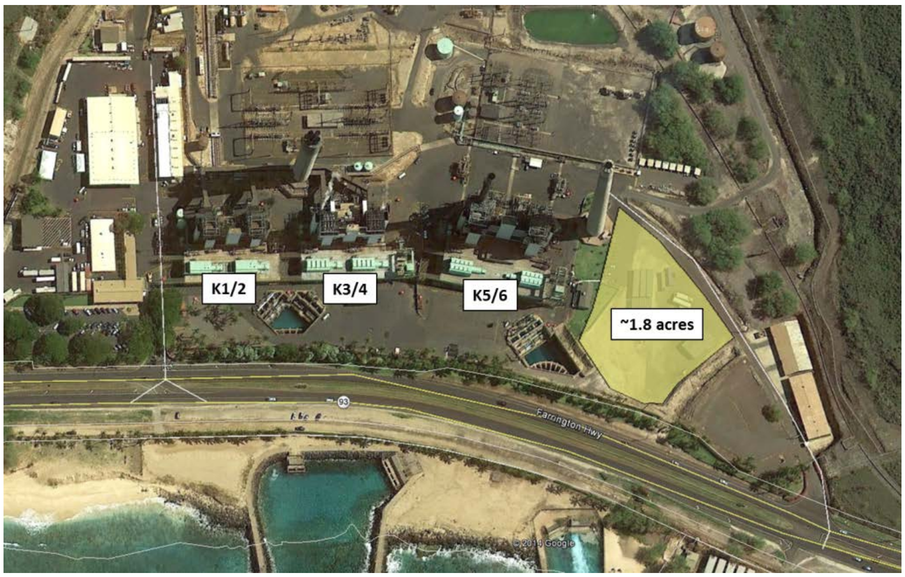

Figure 5-11. Open Space Adjacent to Kahe Units 5 and 6

This space could be developed without the need to incur additional costs that come with removing existing infrastructure.

Based on a 1960 study,[36] the current design elevation at the Kahe Power Plant property to avoid detrimental effects of a tsunami is 24 feet above mean sea level (AMSL). The undeveloped area next to Kahe Units 5 & 6 varies from about 18 feet AMSL on the makai end to about 36 feet AMSL on the mauka end. Based on preliminary review, it is likely that the power house for reciprocating engines could be built at elevations greater than 24 feet AMSL and the equipment that would be located makai of the power house could be elevated on pedestals to ensure that it is elevated at or above 24 feet AMSL. Combustion turbines, as discussed above, could be located such that all equipment is at or above 24 feet AMSL.

[36] "Tsunami Height Predictions at Kahe Point, O'ahu" performed by the Scripps Institution of Oceanography.

Undeveloped Portion of Valley North of Existing Generating Units

There is a large undeveloped area on the north side of the Kahe Power Plant property, of which approximately 40 acres could potentially be used for new firm generation. Current plans call for using much of this available area for the proposed Kahe Utility-Scale PV project. Figure 5-12 shows the property line for the Kahe property, the approximately 40-acre area that could be more readily developed, and the area that is currently reserved for the Kahe Utility-Scale PV project. Note that the area planned for the Kahe Utility-Scale PV project encompasses some land that would be too steep to practically accommodate firm generation.

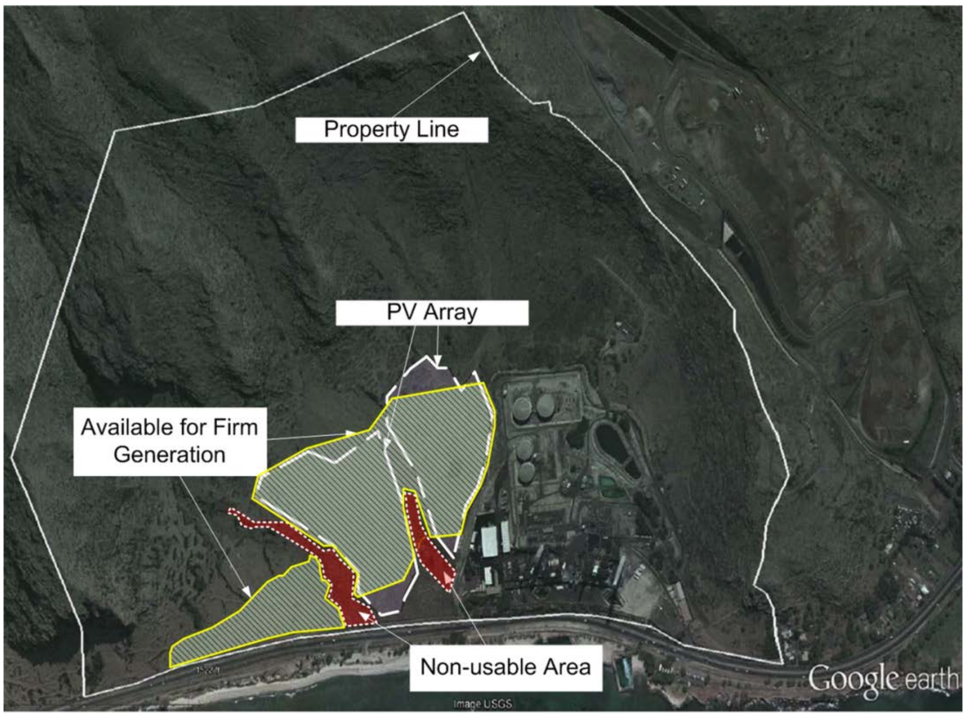

Figure 5-12. North End of Kahe Property

If the Kahe Utility-Scale PV project is approved and constructed and there is a need or desire to use part of that area for new firm generation in the future, a portion of the proposed Kahe Utility-Scale PV project could be moved to the northernmost end of the property at a nominal cost. In this case, approximately 10–12 acres would be available for new firm generation.

Existing Generating Unit Space

The existing area currently occupied by Kahe Units 1–6 is approximately 5 acres (Figure 5-13). There are two potential ways of reusing this area following the retirement of the existing generating units: (1) removing the entire existing infrastructure and building new generating units in their place; or (2) keeping the existing infrastructure in place and using it as a foundation for new generating units. Either way, new replacement generation will need to be installed at other locations prior to the retirement of the existing units.

Figure 5-13. Area of Existing Kahe Generating Units

Removing Existing Infrastructure

The only practical way to remove the existing infrastructure is to remove unit pairs at the same time (that is, K1 & 2, K3 & 4, and K5 & 6). One drawback of this area is that much of the ground elevation is below the recommended height to protect equipment from potential tsunami effects. The equipment on the ground floors of the existing units is elevated on pedestals to account for this. Whether or not it is practical to build elevated foundations for large combustion turbines or reciprocating engines that provide tsunami protection under the current tsunami design standards will need to be evaluated. If the tsunami design standards are updated to be more stringent, siting new generation at ground level in this location may not be practical without building a wall around the entire area.

Without Removing Existing Infrastructure

It may be possible to use the existing infrastructure as the foundation for new generating units. This would reduce the incremental cost of replacement generation by not only the re-use of portions of existing installations, but also by avoiding the large amount of cost associated with removal of existing infrastructure. This scenario would have the flexibility of potentially retiring one unit at a time instead of in unit pairs. Finally, by placing the new generating units and their auxiliary equipment on the elevated turbine decks, the new installations would have additional protection from tsunami effects.

Waiau Power Plant

The Waiau Generating Station has eight active generating units. Six of these units, Waiau Units 3–8, are steam generating units that will be targeted for retirement between 2019 and 2030 as generation tied to the O'ahu grid is modernized. The other two units are simple cycle CTs that are not anticipated to be retired in that timeframe. Consideration must also be given to rebuilding and/or refurbishing of the 46 kV and 138 kV substations located within the confines of the Waiau Power Plant. In addition, Waiau Power Plant is currently the home for one of the "baseyard" operations centers for Energy Delivery and warehousing facilities.

Existing Generating Unit Space

The existing area currently occupied by Waiau Units 3 through 8 (Figure 5-14) is approximately 4 acres. There are two potential ways of reusing this area following the retirement of the existing generating units: (1) removing the entire existing infrastructure and building new generating units in its place; or (2) keeping the existing infrastructure in place and using it as a foundation for new generating units. If the existing infrastructure is entirely removed, new replacement generation will need to be installed at other locations prior to the retirement of existing units at the Waiau Power Plant.

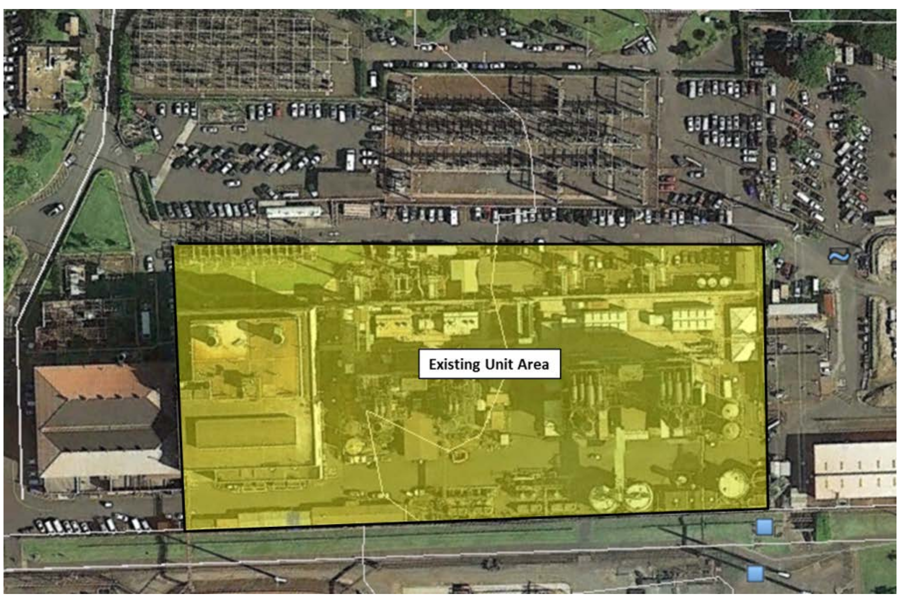

Figure 5-14. Existing Waiau Generating Unit Area

Removing Existing Infrastructure

The only practical way to remove the existing infrastructure is to remove unit pairs at the same time (that is, W3 & 4, W5 & 6 and W7 & 8).

Pearl Harbor is connected to the ocean through narrow channels. In the event of a tsunami, the change in water level within these harbors is expected to be less than 5 feet. Since the harbor acts like a funnel, it would be difficult even during a tsunami for a large quantity of water to be forced through the harbor channel. The results of a 2006 study by the NOAA/Pacific Marine Environmental Laboratory, which included observations from previous tsunamis and 18 modeled scenario events, confirm this reasoning. The newest Civil Defense Map created in 2011 show that all areas mauka of the bike path are outside the tsunami evacuation zone. Therefore, it is anticipated that the entire area at the Waiau Power Plant (shown in Figure 5-14) is viable for installing future firm generating resources.

Without Removing Existing Infrastructure

It may be possible to use the existing infrastructure as the foundation for new generating units. This would reduce the incremental cost of replacement generation by not only the re-use of portions of existing installations, but also by avoiding the large amount of cost associated with removal of existing infrastructure. This scenario would have the flexibility of potentially retiring one unit at a time instead of in unit pairs.

Other Space

Other areas on the Waiau property (Figure 5-15) that could be considered for adding new generating units are:

- Pond area
- Energy Deliver Construction & Maintenance area
- Fuel Oil Tank 1 Area
- Sludge Drying Bed Area
- Waterfront (that is, Power Barge)

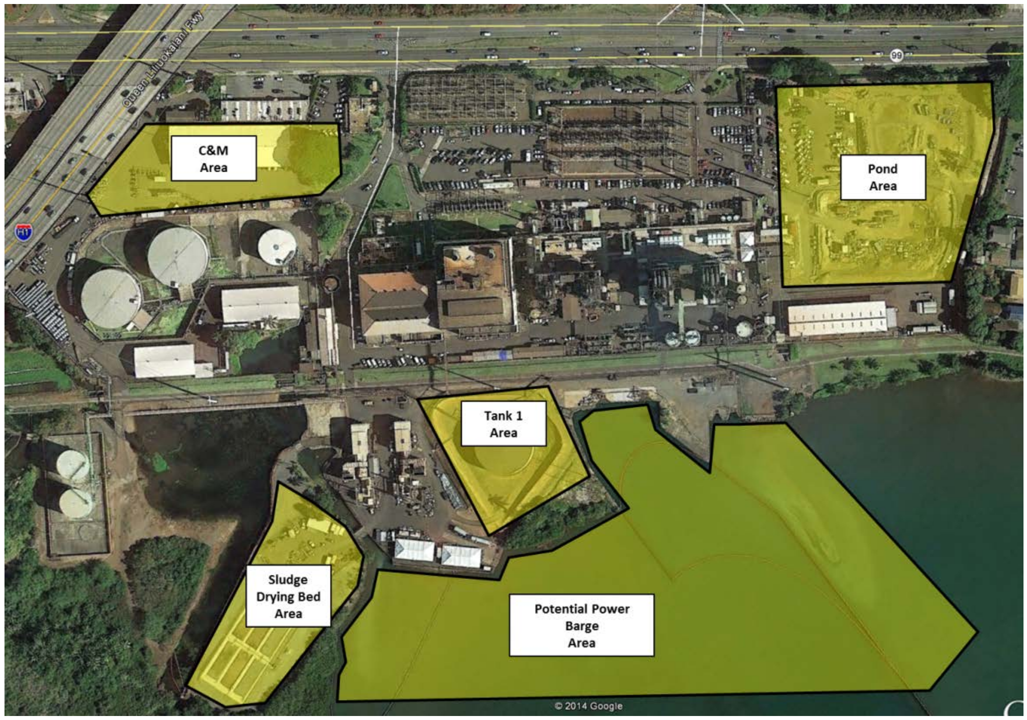

Figure 5-15. Other Areas at the Waiau Generating Station

Pond Area

The Pond Area is the proposed site for containerized LNG deliveries, storage, and vaporization. Since new replacement generation will also need this infrastructure, the pond area is not likely to have sufficient remaining space to locate new generating units.

C&M Area

The Energy Delivery Construction & Maintenance (C&M) warehouse area is currently housing a warehouse and C&M personnel. In the event that the C&M operations are moved away from the Waiau property, this area could be used for other purposes. However, due to its proximity to the elevated H-1 interstate and the need for some open space for parking and equipment laydown, this area is probably not a practical location for siting new generating units.

Fuel Oil Tank 1 Area

It is expected that Fuel Oil Tank 1 will be taken out of service if low sulfur fuel oil is no longer used at the Waiau Generating Station. Therefore, if the tank and the berm are removed, it may be possible to locate new generation in this area.

Despite the available space, locating new generation in this area presents some challenges with turbine foundations (due to the very low elevation above seawater), proximity of 138 kV transmission lines that cross over the area, and susceptibility to detrimental effects of tsunamis.

Sludge Drying Bed Area

The Sludge Drying Bed Area has enough physical space to accommodate new generation. Despite the available space, locating new generation in this area presents some challenges with turbine foundations (due to the very low elevation above seawater) and susceptibility to detrimental effects of tsunamis.

Waterfront Area

It may be possible to utilize the waterfront area (shown in Figure 5-15) for a power barge. Additional engineering study and discussion with the U.S. Navy will be required to determine whether this is a viable and practical alternative for replacement generation at the Waiau Generating Station and what amount of capacity could be installed. Additional pier infrastructure and potentially dredging of the harbor would be required.

Campbell Industrial Park (CIP) Generating Station

The CIP Generating Station currently houses a single simple-cycle combustion turbine (CT-1). The original layout of this site anticipated that CT-1 would be converted to combined-cycle and that a second identical combined-cycle would be installed at the site. However, with the changing requirements of the Oʻahu grid, it is not anticipated that additional combined-cycle generation of this size will be needed so the space could be used for new generation (Figure 5-16).

Figure 5-16. Available Area for New Generation at CIP Generating Station

Permitability

Kahe Generating Station

Air Permit

Any new generating units on the Kahe property will require either a new air permit or modifications to Hawaiian Electric's existing permit, depending on ownership[37]. The

[37] If Hawaiian Electric owns the generation addition, it will require a modification to the existing air permit. If an Independent Power Producer developer owns the new generation, a new air permit will be required.

requirements and the intricacies involved with air permits will vary depending on the scope of the proposed generation additions and the emission levels of the existing units at the time of the permit processing.

Assuming the Kahe region remains an attainment area for all criteria pollutants[38] as defined by the Environmental Protection Agency, it is likely that replacement of the 650 MW (gross) of generation currently installed at the Kahe Generating Station could be permitted. This permitting process may be simpler and quicker if Hawaiian Electric is to be the owner and operator since "netting out"[39] of the emissions from the generating units slated for retirement can be done. Independent Power Producers would not be able to take advantage of this netting out provision.

Special Management Area Permit

The entire Kahe property is within a Special Management Area (SMA). This means that any addition of new generation will be required to obtain a major SMA Permit. As part of the SMA Permit process, an Environmental Impact Statement and community notification will be required.

Although not specifically required by the SMA Permit process, it will be important to get community support for new generating unit assets on the Kahe property to improve the chances that the City Council will issue the permit. The leeward community has often publically expressed a concern that their part of the island is continually and unfairly burdened with unsightly infrastructure. New firm generation will likely be perceived as an additional burden unless steps are taken to reduce the impact.

From a visual standpoint, new power plant infrastructure (generating units, stacks, tanks, switchyards, etc.) in the northern part of the valley may require a commitment to remove a large part of the infrastructure in the currently developed area. This could prove to be very costly and potentially impractical. The possibility of community acceptance of replacement generation is expected to be much greater if the new generation is installed in the area that is already developed, either adjacent to Kahe Units 5 & 6 or within the area encompassed by the current steam units.

Waiau Generating Station

Air Permit

Similar to the Kahe property, any new generating units on the Waiau property will require either a new air permit or modifications to Hawaiian Electric's existing permit,

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[38] The criteria pollutants are nitrogen oxides (NOx), sulfur oxides (SOx), carbon monoxide (CO), particulate matter (PM), Ozone (with Volatile Organic Compounds as a surrogate), lead, and carbon dioxide (CO_2).

[39] "Netting Out" is a process whereby the estimated potential to emit of new generation can be reduced by the actual emissions of the units that will be replaced, thereby potentially reducing the requirements involved with obtaining an air permit and potentially reducing the requirements imposed on the new generating units, including post-combustion controls.

depending on ownership. The requirements and the intricacies involved with air permits will vary depending on the scope of the proposed generation additions and the emission levels of the existing units at the time of the permit processing.

Assuming the Waiau region remains an attainment area for all criteria pollutants, it is likely that replacement of the 280 MW of steam generation represented by Waiau Units 5 through 8 could be permitted. This permitting process may be simpler and quicker if Hawaiian Electric is to be the owner and operator since "netting out" of the emissions from the generating units slated for retirement can be done. Independent Power Producers would not be able to take advantage of this netting out provision.

Special Management Area Permit

The entire Waiau property is within an SMA, so addition of new generation equipment that is visible to the public will require a major SMA Permit. As part of the SMA Permit process, an Environmental Impact Statement and community notification will be required.

The chances of getting community support for new generating unit assets on the Waiau property should be aided by the fact that most of the new infrastructure would blend in with the existing buildings, not be visible outside of existing buildings, or involve the removal of the existing tall boiler units. The primary exception to this is that exhaust stacks for new generation using the existing infrastructure as a base may need to be taller than those currently installed.

CIP Generating Station

Air Permit

Preliminary analysis shows that an air permit for more than 100 MW of new simple-cycle CT generation at the CIP Generating Station should be obtainable. Therefore, physical space is the factor that limits new generation additions to approximately 100 MW at this site.

Water Use Permit

The existing water use permit will be sufficient to cover future needs for water injection of CTs for NOx control.

Substations and Transmission

Kahe Generating Station

The Kahe Power Plant has six 138 kV breaker-and-a-half bays in its substation, with room to add two additional bays. There are six generators (Kahe Units 1–6) and six 138 kV transmission lines connected to the substation, resulting in full use of all existing bays.

The ability to expand the substation will allow for new generation to be added prior to the retirement of existing generating units, provided that the new generation is not located in the area occupied by the active generating units. The connection to the substation of new generating units located adjacent to Kahe Units 5 & 6 would be relatively straight-forward (for example, the site was tentatively identified as a point of interconnection of an ocean thermal facility that would be located off shore from Kahe Power Plant). The same is true for new generating units in the area occupied by the active generating units. The connection to the substation of new generating units installed in the northern end of the valley would not be as straight-forward. The manner of connection would depend on several factors, including which (if any) of the active Kahe generating units are retired at the time of the new generation addition and how much new generation is added. The interconnection could require new 138 kV transmission lines travelling across the Farrington Highway side of the existing units or a new 138 kV substation located next to the added generating units with relocations of current transmission line terminating points.

The six 138 kV transmission lines at the Kahe Generating Station would be able to accommodate at least 650 MW of future generation, as it does now. It is also expected that the transmission system in this location could accommodate additional amounts of capacity. Further study would be required to determine what the capacity limit based on transmission constraints would be for differing generation technologies.

Waiau Generating Station

The Waiau Generating Station has six breaker-and-a-half bays in its 138 kV substation. It may be possible to add an additional bay, but it would not be simple since there is very little room to do so. Further study will be required to determine whether expansion could be practical. There are six generators (Waiau Units 5–10) and eight 138 kV transmission lines connected to the substation, resulting in full use of all existing bays. The station also has a 46 kV substation to which two generators (Waiau Units 3 & 4) are tied.

Although expansion of the 138 kV substation may prove to be impractical, Waiau Units 3 & 4 are scheduled to be deactivated by the end of 2016. This could allow some amount (approximately 100 MW) of new generation to be connected to the 46 kV system prior to retirements of Waiau Units 5–10. This would result in full retirement of Waiau Units 3 & 4.

Based on the limited physical space on the Waiau property, and not withstanding the need to refurbish or replace the existing substation equipment, it is anticipated that the existing substations could accommodate any new generating capacity proposed at this location. Timing of additions and routing of associated 138 kV interconnections to the substation may not be straight-forward. However, it is anticipated that any complications involved with these connections could be resolved satisfactorily.

CIP Generating Station

Any generating units at the CIP Generating Station will be connected to Hawaiian Electric's 138 kV AES Substation, which is co-located on the same property. The AES Substation has three 138 kV breaker-and-a-half bays, with room to add two or three additional bays. There are three generators (CIP CT-1, AES, and HPower) and three 138 kV transmission lines currently connected to the substation, resulting in full use of all existing bays.

The interconnection of new generating units at the CIP Generating Station would be very straight-forward due to the ability to expand the AES Substation. Additionally, there are already spare underground conduits from the generating unit area to the substation that can accommodate new 138 kV underground connections to the substation. Based on previous studies, the addition of 100 MW of generation is not expected to trigger the need for a new 138 kV transmission line coming out of the AES Substation. However, the results of that study should be updated due to several changes to the grid in the area that affect the baseline assumptions used in the study.

Water Supply

Kahe Generating Station

The Kahe Generating Station has access to reclaimed water from the Honouliuli Wastewater Treatment Facility and city potable water. The reclaimed water is used as the feed to the existing demineralizer system that purifies water for steam unit makeup needs. The potable water is used for domestic needs and equipment washing, but can act as a backup feed to the demineralizer system in case reclaimed water supply is disrupted.

The current guaranteed allocation of reclaimed water to the Kahe Generating Station is 50,000 gallons per day, but the agreement with the Board of Water Supply also allows for Hawaiian Electric to consume up to 140,000 gallons per day on average with a peak of 310,000 gallons per day if available. Installation of 100 MW of new combustion turbines at the site would increase the daily need by approximately 35,000 gallons per day.[40] Coupled with need of any remaining steam units, the total demand would likely exceed the guaranteed allocation of reclaimed water. However, it is expected that the current guaranteed allocation of reclaimed water could be increased to meet the higher demand.

[40] Full load operation of an LMS100 requires approximately 70,000 gallons per day (48 gallons per minute). Assuming a 50% capacity factor, the demand for demineralized water would be approximately 35,000 gallons per day. If using a demineralizer, which is what is currently installed at Kahe, the increase in demand for reclaimed water would also be approximately 35,000 gallons per day. If a reverse osmosis system is used to purify the water, reclaimed water needs would increase approximately 70,000 gallons per day due to the large amount of reject water produced by this type of system.

At a minimum, potable water could be used to supplement the reclaimed water supply as necessary.

The current demineralizer system has the capacity to produce 190 gallons per minute of demineralized water. Depending on the remaining steam unit needs, this could potentially be sufficient to cover the needs of 100 MW of new combustion turbines. If not, additional water treatment equipment would be required.

New reciprocating engines would have very limited needs for demineralized water, so the existing allotment of reclaimed water and demineralizer capacity would likely be sufficient to cover any additional needs brought on by their installation.

Waiau Generating Station

The Waiau Generating Station has access to sufficient amounts of pond water that should cover any operational needs that would arise from the installation of new generating units. Whether the existing water treatment system, which has the capacity to produce up to 135 gallons per minute of treated water, would be sufficient to cover the needs of new combustion turbine installations would depend on how much new generation is installed and what steam units remain in operation at the time of installation. With the retirement of existing generation units, however, sufficient space will be available to install new water treatment equipment that may be needed.

CIP Generating Station

The water treatment system at the CIP Generating Station can produce up to 350 gallons per minute of demineralized water, which is sufficient to provide the full-load needs of both CT-1 and an additional 100 MW of simple-cycle combustion turbines. The water treatment system can accept feed water from three sources: 1) reclaimed water; 2) groundwater; and 3) potable water. Although the reclaimed water allotment of 70,000 gallons per day would not be enough to cover continuous full load operation of CT-1 and new combustion turbines, it may be sufficient to supply the needs of actual operation, depending on the capacity factors of the units. In cases where the combustion turbines have capacity factors that result in water needs exceeding the reclaimed water allotment, the groundwater supply at this site is sufficient to supply continuous full load operation.

Fuel Supply

While having access to fuel delivery pipelines is ideal, it is not necessary for a site to have this capability to be an ideal location for adding new generation. If required, fuel can be trucked to generating stations in lieu of pipeline delivery.

The Kahe and Waiau Generating Stations both receive fuel oil via pipeline deliveries and the CIP Generating Station has its fuel trucked. This arrangement will continue in the future for fuel oil deliveries, regardless of whether new replacement generation is added at these sites.

That said, fuel oil is longer expected to be the primary fuel source once liquefied natural gas (LNG) is imported to O'ahu. It is likely that LNG will initially be trucked to the Kahe and Waiau Generating Stations and there are plans to install at these sites infrastructure to receive, store, vaporize, and forward the fuel to the generating units. Eventually there may be plans to build gas pipelines to these locations from a central LNG storage and regasification unit if it appears to be cost-effective. The planned infrastructure will not only serve existing generating units at the Kahe and Waiau Generating Stations, but will also satisfy fuel logistics requirements for new generation at these sites.

Currently there are no plans to build gas infrastructure at the CIP Generating Station as it is not expected to be cost-effective to convert CIP CT-1 for gas use since it has a very low capacity factor. However, that may change in the future if the use of CIP CT-1 is expected to increase or if new generation is added to the site. Future gas infrastructure could either be in the form of LNG receiving, storage, vaporization, and fuel forwarding equipment located on the CIP Generating Station site or a pipeline delivering gas from LNG facilities elsewhere.

GENERATION PORTFOLIO OF AN O'AHU–MAUI GRID INTERCONNECTION

Two independent analyses were developed to test the economics of constructing a 200 MW DC bi-directional transmission tie between the islands of Maui and O'ahu. The analysis was designed to identify the potential savings in power costs created by the cable. The forecast of savings then creates the benchmark, "the price to beat", for owning and operating the transmission cable. In our analysis, we did not explicitly analyze additional system security costs that could be potentially incurred if the cable configuration was one 200 MW cable versus two 100 MW cables. A redundant connection (two 100 MW cables) has potential system benefits since the N-1 contingency is closer to the current system requirements versus the alternative of the largest outage potentially being 200 MW. The trade-off for the redundant cables is likely to be close to a doubling in the cost of constructing the transmission link.

The independent analyses were performed by Black & Veatch and PA Consulting, members of the modeling team assembled for the PSIP analyses. The production cost simulation models used by both firms in this analysis are described in Appendix C. The analyses used slightly different approaches. One approach is not considered preferred to the other, rather the different approaches provide different perspectives. The conclusion from the analysis of both companies indicates that the transmission cable is not a cost-effective solution. The cable could not possibly be built for the estimated amount to be cost-effective. Based upon the two analyses, the NPV of the estimated savings excluding the cost of the transmission cable are $60 M–$ 175 M, respectively. For the cable system to be cost effective, the NPV for the design, construction, operation, and maintenance of the cable system would have to be less these amounts.

A discussion of the analyses performed follows.

A. PA Consulting Analysis

PA Consulting developed an analysis of the transmission cable potential benefits using the AURORA hourly production simulation model. Six cases were developed where PA Consulting allowed the AURORA model to use its long-term expansion algorithm to develop the least cost generation expansion plan subject to constraints and certain assumptions. The major assumptions and constraints included:

- Starting with the existing generation assets on Maui and O‘ahu.
- Assuming that LNG would be available on both islands starting in 2017.
- Assuming that distributed generation (that is, DG-PV) would be built out on both islands.
- Generator operating characteristics, operating costs, new unit costs, and fuel costs consistent with the assumptions documented in this document.

Six cases were modeled and in each case the Aurora model was allowed to identify the least cost generation mix. The six cases were combined to create four scenarios and create a range of estimated savings.

1. Thermal Future with No Grid Tie. In this scenario, the model was not allowed to select new utility-scale wind and solar projects beyond the projects that have already been included in the Base Case for Maui. These scenarios roughly tied to the base case scenarios developed for each of the islands.

2. Grid Tie–Thermal Future. In this scenario, the model selected the least cost generation expansion plan assuming the two islands were connected by a 200 MW transmission link. The two systems were modeled as one pool where they shared a reserve margin and the system was jointly dispatched subject to the transfer constraint between the islands. The model was constrained to not selecting new utility-scale wind or solar beyond projects already included in the Base Case for Maui.

3. Renewable Future with No Grid Tie. In this scenario, the model was allowed to select the least cost mix of resources including utility-scale wind and solar.

4. Grid Tie–Renewable Future. In this scenario, the model selected the least cost generation expansion plan assuming the two islands were connected by a 200 MW transmission link. The two systems were modeled as one pool where they shared a reserve margin and the system was jointly dispatched subject to the transfer constraint between the islands.

B. Black & Veatch Analysis

The Oʻahu-to-Maui transmission cable analysis was based on the assumption that each island would need to be able to meet both load and system security requirements independently; that is, each island could continue to provide energy and grid stability in the event that the transmission cable failed. Thus, the analysis uses a base case that allows each island to meet its own requirements independently; this system configuration was maintained across the alternate cases evaluated. This base case includes distributed generation build-out; additional utility-scale renewable projects; LNG; and improvements to thermal fleet flexibility, efficiency, and reliability through retirements and new generation additions.

The potential benefit to the transmission cable stems from the difference in production cost between Oʻahu and Maui—particularly the potential for low-cost, higher-production wind generation. Thus, the Black & Veatch analysis considered additional wind installed on Maui and, via the transmission cable, energy was allowed to flow between Maui and Oʻahu. Except for this additional wind on Maui, the remainder of the generating system remained consistent with the base case. Both the transmission cable and the additional Maui wind were modeled as online in 2022.

Since generation on the margin on Maui is cheaper than generation on Oʻahu, given the presence of a transmission cable, Maui generation will be used to meet Oʻahu demand. In absence of sufficient additional wind, Maui thermal units will run to assist in meeting Oʻahu demand, and Oʻahu thermal units will back down. As additional wind is installed on Maui, Oʻahu generation decreases, Maui thermal generation decreases, and Maui wind generation increases.

The optimum scenario evaluated by Black & Veatch incorporates an additional 300 MW of wind on Maui in 2022, coincident with the assumed online date of the transmission cable. This scenario saw significant (30%) decrease in non-renewable generation on Oʻahu. On Maui, renewable generation more than doubled. The resulting system-wide generation savings, excluding the cost of the interconnection transmission cable, would have an NPV of $80 million.

ENVIRONMENTAL COMPLIANCE

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. Chapter 9 of the 2013 IRP Report[41] described the environmental requirements of the Companies. This section describes any updates to the filing and provides additional environmental requirements that were not discussed.

Hawaiian Electric Environmental Compliance

Hawaiian Electric carefully analyzed alternatives for environmental compliance in the 2013 IRP. Obtaining compliance through fuel switching was the most economical alternative.

MATS Compliance Strategy[42]

Based on field test results to-date, Hawaiian Electric observes that blending the equivalent of approximately 40% to 50% diesel into the current low sulfur fuel oil provides compliance with the MATS PM standard. Fuel blending is a less costly alternative to fuel switching to 100% diesel. When LNG becomes available, switching to LNG will also be compliant with MATS.

National Ambient Air Quality Standards (NAAQS)

As shown in the 2013 IRP, compliance with NAAQS through the use of LNG was the lowest cost option.

Greenhouse Gas (GHG) Regulations

Governor Abercrombie recently signed Hawai‘i Department of Health (DOH) GHG regulations which became effective on June 30, 2014.[43][44]

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[41] Docket No. 2012-0036, Integrated Resource Planning for the Hawaiian Electric Companies, filed June 28, 2013.

[42] Hawaiian Electric was granted a one year MATS compliance extension, which places the compliance deadline at April 16, 2016. A second one year extension is available to utilities through an Administrative Order that would be issued by the EPA. Based on the evaluation criteria established by the EPA in a December 16, 2011 Policy Memorandum, the second one-year extension must be based on a system reliability assessment and is considered a much more difficult extension to obtain.

[43] *Hawai‘i Administrative Rules, Title 11, Department of Health, Chapter 60.1*. Amendments adopted June 19, 2014, effective June 30, 2014. http://health.Hawai‘i.gov/cab/files/2014/07/HAR_11-60_1-typed.pdf.

The regulations requires entities that have the potential to emit GHGs of more than 100,000 tons per year of carbon dioxide equivalent (CO_2e) to reduce GHG emissions by 16 percent below 2010 emission levels by January 1, 2020, and maintain those levels thereafter. Ten power plants operated by Hawaiian Electric Companies meet the applicability condition. Hawaiian Electric has one year to submit GHG emission reduction plans to DOH for its affected power plants. These plans will explain how each facility intends to meet its GHG reduction threshold by the 2020 target date, what technology will be employed, and how the reduction will be sustained going forward.

For greater flexibility, the Hawaiʻi State GHG Rules allow affected facilities to "partner" among each other to meet GHG reduction targets. That is, one affected facility can agree to "transfer" some of their allowable GHG emissions to another facility to meet the reduction target for the second facility in cases where that facility might not be able to meet their target on their own.

In addition, if the statewide GHG emission limit is met prior to 2020 and GHG emission projections indicate ongoing maintenance of the statewide limit, the objectives of Hawaiʻi Act 234 would be considered satisfied and no facility-wide GHG cap would apply to affected facilities.

On June 18, 2014, EPA published a proposed rule that would establish GHG performance standards for existing power plants under Clean Air Act Section 111(d).[45]

EPA is proposing state-specific GHG emission reduction targets and a two-part structure for states to achieve the targets. States would be required to meet an interim goal on average over the ten year period from 2020–2029 and a final goal in 2030 and thereafter. EPA also identifies a number of potential options for states to meet the proposed targets. Using EPA's 2012 baseline, Hawaiʻi would have to reduce its statewide CO_2 emission rate by approximately 15% to meet EPA's proposed 2030 final goal.

EPA developed the proposal pursuant to a 2013 directive from President Obama. The directive requires EPA to finalize the proposal no later than June 1, 2015, which will start the one-year period for states to complete and submit state plans to EPA. Hawaiian Electric is studying EPA's proposal and will actively participate in the rulemaking.

Hawaiian Electric is committed to taking direct action to mitigate the contributions to global warming from electricity production. Such action has, and will, continue to include promoting aggressive energy conservation and transitioning to clean, efficient and eco-effective energy production in all markets that the Company serves. Hawaiian

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[44] The DOH amended the Hawaiʻi Administrative Rules, Chapter 11-60.1 to reduce GHG emission in Hawaiʻi to 1990 levels by January 1, 2020 pursuant to Act 234, 2007 Session Laws (codified in part in Hawaiʻi Revised Statutes, §342B-71 to 73).

[45] 79 Fed. Reg. 34830.

Electric is already taking active steps to mitigate contributions to global warming by investing in and committing to use biofuels, renewable generation, and energy conservation.

316(b) Fish Protection Regulations

Section 316(b) of the Clean Water Act requires that National Pollutant Discharge Elimination System (NPDES) permits for facilities with once-through cooling water systems ensure that the location, design, construction, and capacity of the systems reflect the best technology available to minimize harmful impacts on the environment. Most impacts are to early life stages of fish and shellfish that become pinned against cooling water intake structures (impingement) and are drawn into cooling water systems and affected by heat, chemicals, or physical stress (entrainment).

The EPA issued the final 316(b) fish protection rule on May 19, 2014. This rule titled, *Final Regulation to Establish Requirements for Cooling Water Intake Structures at Existing Facilities*, applies to Hawaiian Electric's Honolulu, Kahe, and Waiau steam electric generating stations. The Kahe and Waiau facilities are required to comply with the impingement and entrainment standards. The Honolulu facility, due to its lower actual intake water flow when operating, may only have to comply with the impingement standard. Honolulu is currently deactivated and will only be required to comply with the 316(b) fish protection rule when it is reactivated.

The final regulation does not specify the best technology available (BTA) standard for entrainment, but states that "the Director must establish BTA standards for entrainment for each intake on a site-specific basis." [§125.94(d), Page 538] In Hawai'i, the "Director" is the Director of the Hawai'i Department of Health (DOH).

Significant studies at Kahe and Waiau need to be completed before the DOH can make a final determination of the technology requirements for the affected facilities. Six years of impingement and entrainment data have been collected at Kahe and Waiau and will be used to complete the required studies for these facilities. A preliminary review of the data indicates that closed-cycle cooling (CCC) or cylindrical wedgewire screens will not be required to comply with the 316(b) rule, but fish friendly traveling screens and fish return systems may be required.

No firm deadline for compliance is specified in the final rule; facility-specific compliance schedules will be developed based upon the results of the required studies, in consultation with DOH, and in coordination with the facilities' NPDES permit cycles.

6. Financial Impacts

The PSIP presents a Preferred Plan for the transformation of O‘ahu’s power system. The analyses used in the development of the Preferred Plan were based on numerous assumptions (discussed in Chapter 4 and summarized in Appendix F).[46] The transformation of the power system will require significant investments by both the company and third parties to build the necessary flexible, smart, and renewable energy infrastructure needed to reliably serve customers across O‘ahu. The PSIP requires a reliable, well-maintained transmission and distribution (T&D) system, a thermal generation fleet to firm variable renewables, and related infrastructure to achieve this transformation.

A strong and resilient grid is foundational for meeting our customers’ needs for safe and reliable electric service, serving new customers and new electric loads such as electrified transportation, and providing energy services more generally. Investments to maintain, and as necessary expand, this foundational infrastructure are termed “foundational investments”. These foundational investments are essential and complementary to the transformational investments defined by the PSIP. The investment requirements of the PSIP, including both transformational and foundational investments, are presented in detail in Appendix K. The magnitude and impacts of these investments are analyzed and discussed in this chapter in terms of customer affordability as measured by full service residential customer bill impact in real dollars (that is, 2014 dollars).

By combining the transformational together with the foundational investments, including their impact on fuel and O&M expenses, we provide a comprehensive analysis of customer affordability. Implicit in these financial analyses is the Company’s ability to maintain affordable and ready access to capital markets.

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[46] We acknowledge that actual circumstances may vary from what was assumed in the analyses, and accordingly, the PSIP will need to be revised and/or actions will need to be reviewed and updated from time to time.

RESIDENTIAL CUSTOMER BILL IMPACTS

The rate reform proposed in the DGIP[47] provides a rate design that reduces average monthly bills in real terms for average[48] residential full service[49] customers to approximately 22% below 2014 levels by 2030, while more fairly allocating fixed grid costs across all customers. The residential customer bill impact with DG-PV reform is discussed in detail in the next section of this chapter. The discussion immediately below presents the customer bill impact under current rate design to facilitate the comparison with the customer impact under the proposed DG-PV reform.

As shown in Figure 6-1, assuming the current rate design, the full service residential customer bill will vary in the near term, peaking at an increase of approximately 4% in real terms in 2023 as investments are made to transform the system.[50] The bill impact of these capital investments is mitigated by the conversion of several assets to lower cost containerized liquefied natural gas (LNG) in 2017. Beginning in 2023, once future investments to transform the grid taper off, the average full service residential bill will decline throughout the remainder of the planning period to approximately 16% below 2014 levels, in real terms, by 2030.

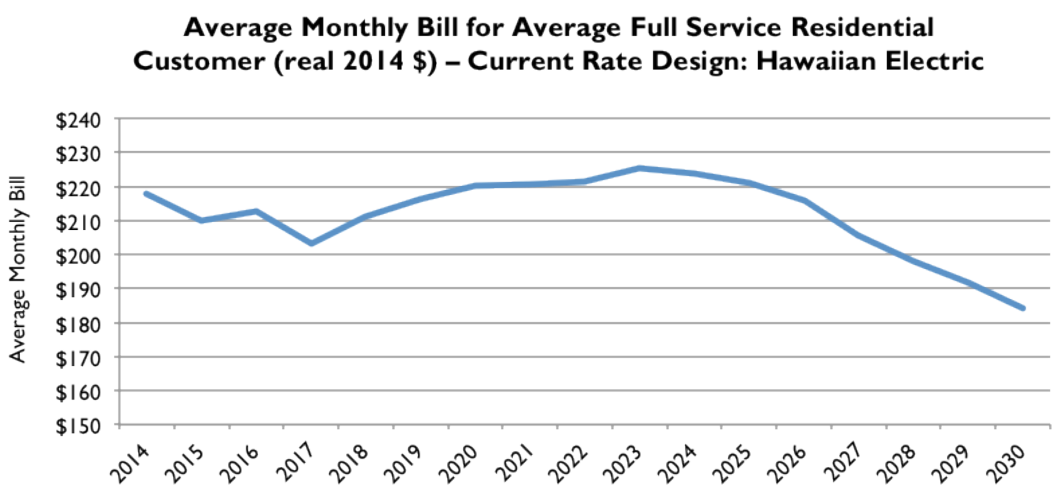

Figure 6-1. Average Full Service Residential Customer Bill Impact under Current Rate Design

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47 The Companies filed their *Distributed Generation Interconnection Plan* (DGIP) on August 26, 2014.

48 Average is defined by taking the total usage across all full service customers and dividing by the number of full service customers in a given year. The average bill is not meant to project an actual future customer bill, but is illustrative of the bill impacts anticipated for customers with an average amount of usage across full service residential customers.

49 Full Service Customer is defined as any residential or commercial customer that imports the entirety of their energy demands from the grid, and does not self-consume or export any energy derived from distributed energy resources co-located with their load.

50 This increase reflects the benefit reduced fuel costs resulting from moving to a containerized LNG solution in the 2017 timeframe.

These bill impact analyses assume that the residential customer class continues to be responsible for its current percentage of the total revenue requirement. This is a reasonable simplifying assumption, given that this class responsibility has been largely unchanged over the last 20 years or more.

RESIDENTIAL CUSTOMER BILL IMPACTS WITH DG-PV REFORM

In this section, we estimate the average monthly bill for average, full service and DG residential customers assuming specific adjustments to rate design for all residential customers, including those with DG-PV. It is important to note that this is one potential approach to rate design among many other possibilities. Use of this approach for customer bill projections is not meant to advocate for or against this rate design versus any other, but instead is meant to demonstrate the relative impact to residential customer bills as a result of one possible set of rate design changes intended to address various challenges and concerns as discussed in the DGIP filing.[51]

The financial analysis utilizing this rate construct illustrates how such an alternative approach to DG-PV could result in average monthly bills for average full service residential customers that are, in real terms, 22% lower in 2030 as compared to 2014 (that is, an additional 7% lower than under the current rate design) and more fairly allocates fixed grid costs across all customers.

Outline of Hypothetical DG-PV Reform (DG 2.0)

The Company's strategic vision for DG-PV encompasses reform of the rates governing DG-PV interconnections under an overall approach to distributed generation called "DG 2.0". As part of DG 2.0, the current net energy metering (NEM) would be replaced with a tariff structure for DG systems that more fairly allocates fixed grid costs to DG customers and compensates customers for the value of their excess energy. For modeling purposes, DG 2.0 is assumed to begin for all new DG customers in 2017; customers who interconnect before 2017 will retain the tariff structures under which they applied.

As a party to Order No. 32269 issued by the Commission on August 21, 2014, the Companies view this as an opportunity to evaluate the precise nature and timing of the DG 2.0 rate reform. A preliminary set of assumptions regarding DG 2.0 has been made to facilitate the financial and capacity modeling performed in this PSIP and the DGIP, but these assumptions should not be interpreted as a policy recommendation.

[51] Additional policy options are described further in the DGIP.

These rate assumptions adhere to the underlying principles of the Company's DG strategy and include the following:

- A fixed monthly charge applied to all customers, allocating fixed customer service and demand costs in a fair, equitable, and revenue-neutral manner within customer classes.
- An additional fixed monthly charge applied only to new DG customers to account for additional standby generation and capacity requirements provided by the utility.
- A "Gross Export Purchase model" for export DG. Under this model, coincident self-generation from DG-PV and usage is not metered and customers sell excess electricity near wholesale rates and buy additional electricity at variable retail rates.

For the purposes of these projections, fixed monthly charges are assumed to comprise demand and customer service charge components.

The fixed demand charge has been estimated in two steps. First, a capacity requirement across all customers that would minimize cost shifts to low-usage customers was determined. Second, the fixed cost of meeting this capacity requirement for production, transmission, and distribution was calculated. An additional demand charge was also applied to DG 2.0 customers due to the higher peak capacity requirements that DG customers have, on average, compared to the broad class of residential customers.

In addition to fixed capacity-based charges, monthly customer charges were estimated by allocating the fixed costs associated with servicing individual customers across all relevant households. These costs were assumed to be uniform within customer classes.

These fixed charge projections, along with assumed feed-in tariff (FIT) rates under the envisioned Gross Export Purchase model are shown in Table 6-1.

Residential Customer Groups	Monthly Fixed Charge – All Residential Customers	Monthly Fixed Charge – DG Only	Feed-in Tariff Purchase Price	Tariff for Energy Consumed from Grid
Current NEM Customers	$55	n/a	n/a	n/a, within NEM energy balance, retail rate for any shortfall
DG 2.0 Customers	$55	$16	$0.16	Retail rate
Full Service Customers	$55	n/a	n/a	Retail rate

Table 6-1. Estimated O'ahu DG 2.0 Customer Charges and Feed-in Tariff Rate

OVERVIEW OF DG-PV FORECASTING

As customers respond to a revised set of market incentives such as DG 2.0, the rate of DG-PV installations will change. A market-driven forecast for DG-PV demand, assuming DG 2.0 is implemented in 2017, has been developed. At a high level, these forecasts estimate what DG-PV uptake will be as regulatory reform transitions away from existing DG programs (including NEM) over the next two years and implements DG 2.0 in the medium term. Accordingly, this PSIP has used DG-PV forecasts that were based on two distinct phases of DG uptake.

From 2014 to 2016, a set rate of interconnection under existing DG programs was assumed, based on simplifying assumptions about queue release and the pace of new applications.

From 2017 onward, the DG 2.0 tariff structure is assumed to apply across all customer classes.[52] Using benchmarked relationships between the payback period of PV systems and customer uptake rates, we projected market demand for new PV systems among all residential and commercial customer classes.

Based on this methodology, the projected number of residential customers on O‘ahu with DG-PV would grow by about 130% from approximately 27,500 at the end of 2013 to approximately 63,000 in 2030. While this forecast will undoubtedly shift as more detailed policies are developed, it has been used as an essential input for all of the PSIP analyses.

Residential Customer Bill Impacts Under DG 2.0

The reform of DG-related rates has a material impact on average monthly bills for full service residential customers. As shown in Figure 6-2, the projected average monthly bill for an average full service residential customer drops by 22% in real terms over the 2014 to 2030 period.

[52] With the exception of grandfathered current NEM customers.

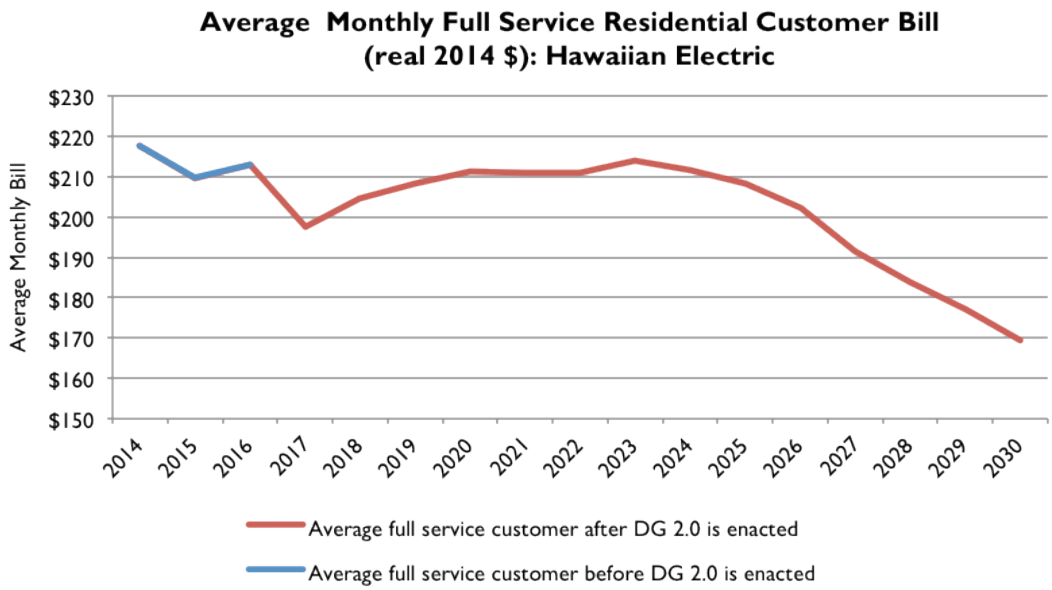

Figure 6-2. Average Full Service Residential Customer Bill Impact under DG 2.0

As discussed above, DG 2.0 is assumed to take effect in 2017. This results in a bill reduction for full service residential customers in 2017 that grows throughout the planning period, as compared to the current rate design.

Under the DG 2.0 concept, current NEM customers would see an increased average monthly bill due to the increased fixed monthly demand and customer charges for all customers beginning in 2017, partially offset by the decrease in variable retail rates charged to all residential customers for electricity taken from the grid. The bill impact for new residential DG customers would include those charges, as well as the fixed charge for higher capacity and their net cost from the "Gross Export Purchase" model. Average full service customer average monthly bills would decrease under DG 2.0, despite the increase in fixed monthly demand and customers charges, as a result of the decrease in variable retail rates. Bill impacts for these customer groups, both under the current tariff structure as well as DG 2.0, are shown in Figure 6-3.

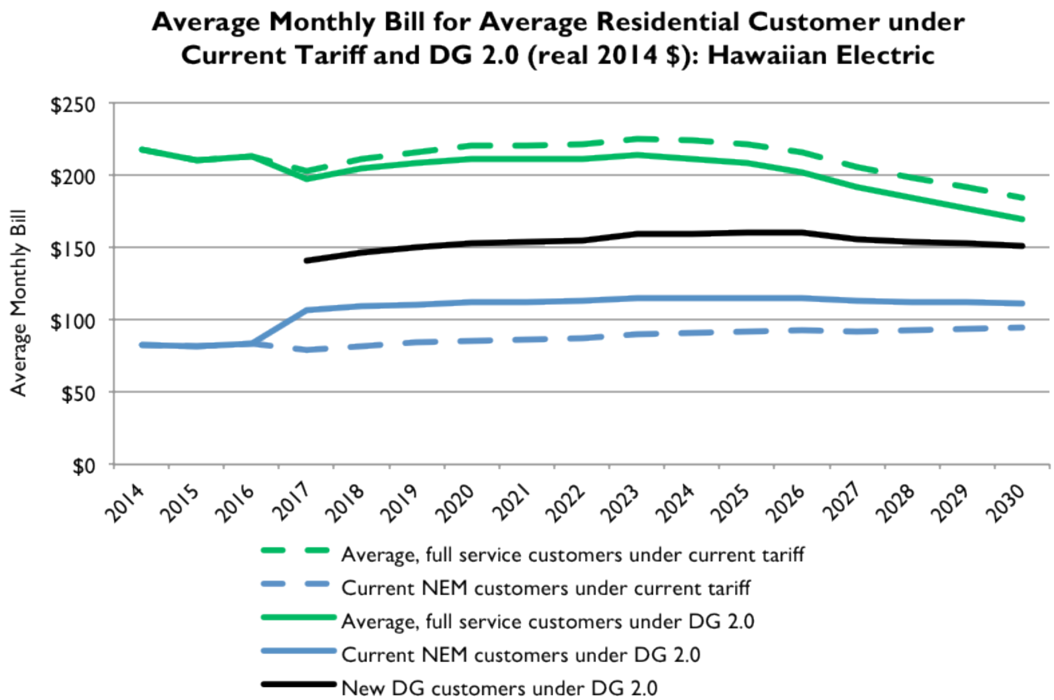

Figure 6-3. Average Residential Customer Bill Impact under Current Tariff and DG 2.0

POTENTIAL POLICY TOOLS TO FURTHER SHAPE CUSTOMER BILL IMPACTS

This PSIP, coupled with the DGIP and the IDRPP, demonstrate a comprehensive path forward to achieve higher levels of renewable generation, lower long term costs, provide additional options for customers to manage their energy costs, and more fairly allocate fixed grid costs across all customers while preserving an economic incentive for customers to opt for DG. To further mitigate these bill impacts, there are a range of policy tools that could be applied.

Statewide Rates

As shown in the three PSIPS, the average monthly bill for an average full service residential customer for the three operating utilities under DG 2.0 vary in terms of both magnitude and timing (Hawaiian Electric: Figure 6-4; Maui Electric: Figure 6-5; and Hawaiʻi Electric Light: Figure 6-6).

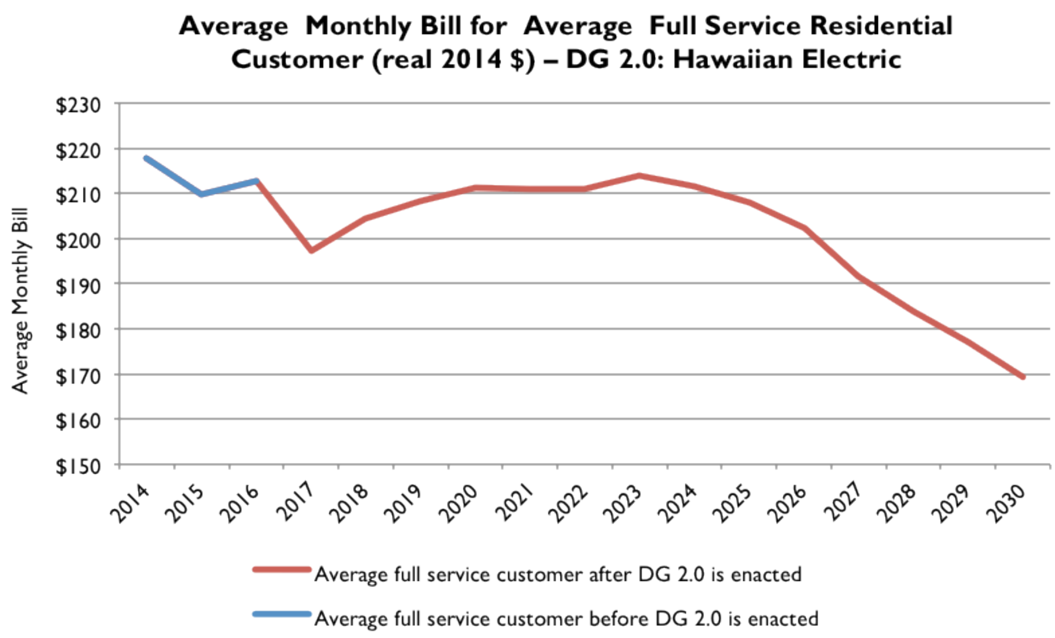

Figure 6-4. Average Monthly Bill for Average Full Service Residential Customer, Hawaiian Electric: DG 2.0

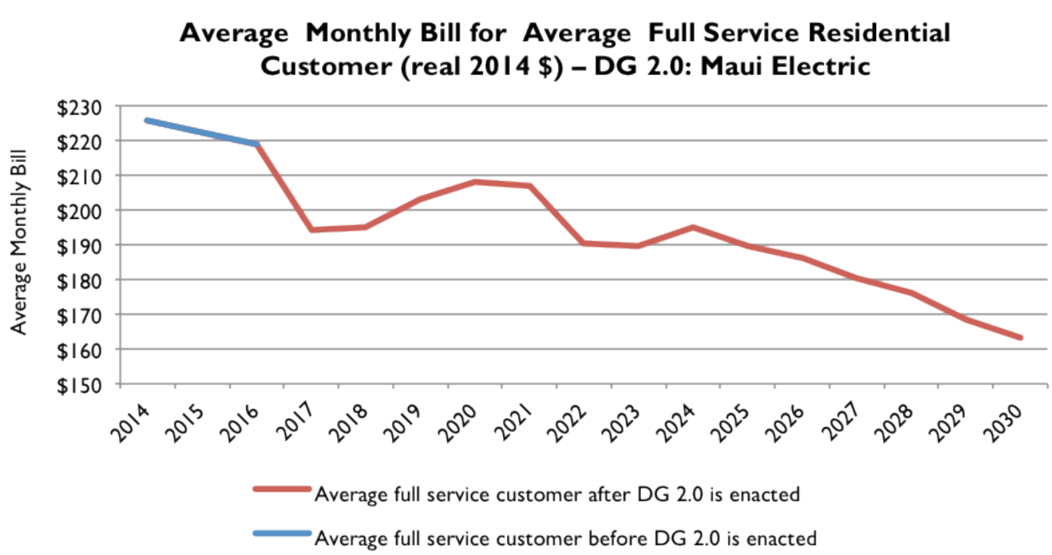

Figure 6-5. Average Monthly Bill for Average Full Service Residential Customer, Maui Electric: DG 2.0

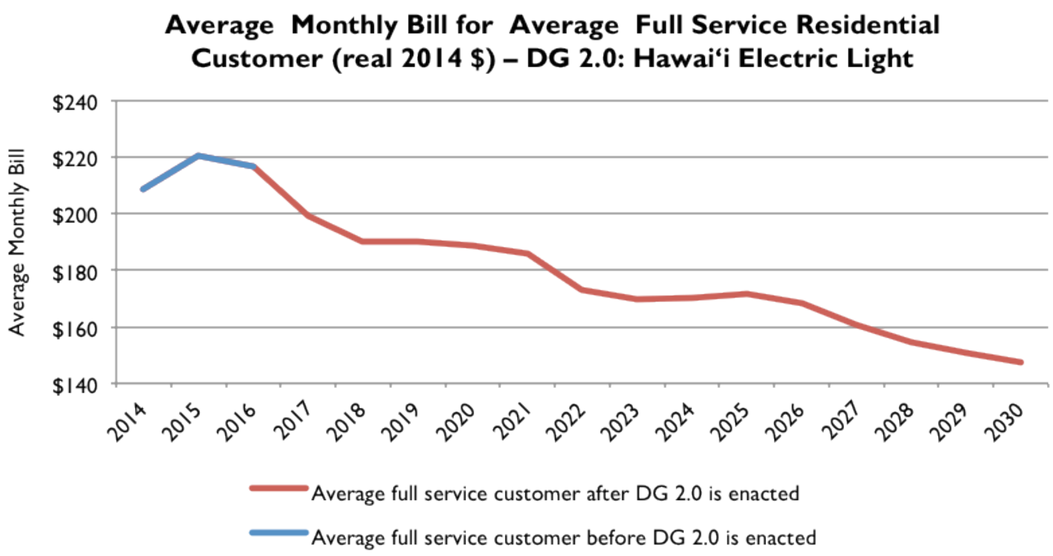

Figure 6-6. Average Monthly Bill for Average Full Service Residential Customer, Hawai'i Electric Light: DG 2.0

A shift toward a statewide rate approach, perhaps beginning with a statewide power supply rate component, would be a tool to smooth out changes impacting individual grids. This approach would also be logical given the "statewide" nature of the RPS goals.

In addition, moving to statewide rates would likely create regulatory efficiencies which would also serve to mitigate rate increases. For example, costs should be reduced by filing a single rate case every three years, rather than filing three rate cases every three years.

Transportation Electrification Incentives

Accelerating the growth of the electric vehicle (EV) market in Hawai'i represents a significant opportunity to impact state emission policy goals, while having a positive impact on the cost of electricity by spreading the fixed costs of the grid over larger usage, and by developing a large load eligible for demand response. Electric vehicles can develop into a sizable, flexible, incremental load. Each of these attributes contributes to helping reduce long-term energy costs. State policy adjustments, such as expanded incentives for purchasing EVs, could help further the reduction of long-term energy costs.

As a new incremental load, EVs are unlikely to drive new, large investments in the grid. Thus, it is likely that the marginal T&D cost to serve EV load is very modest[53], so energy sales for EVs would help lower the cost of the grid to other, non-EV customers.

[53] This would remain true as long as EV charging is done at times of high renewable generation, allowing excess generation to be used. The cost of an infrastructure and DR controls to achieve this end is not included in the PSIP analysis.

State Tax Policy

There are a number of ways in which alternative State tax policy can potentially help mitigate electricity prices. Two potential opportunities are described below.

Today, approximately 9% of the average customer bill is comprised of taxes other than income taxes. The investment plans contained in this PSIP will result in the deployment of over $6.4 Billion in capital over the 2015 through 2030 time period. A limited duration excise tax exemption for certain types of investments (such as energy storage) would help reduce the impact on electric customers, while leaving state tax receipts at traditionally expected levels.

Another aspect of tax policy to be considered is the various revenue taxes the Company's customers pay. These taxes automatically increase with any increase in bills, such as the near-term increases driven by the PSIP and DGIP transformational investments. However, any change in the Public Utilities fee component of revenue taxes must be made in light of the need for additional funds required for the Commission and Consumer Advocate to implement regulatory changes.

PROJECTED REVENUE REQUIREMENTS FOR THE PERIOD 2015–2030

The bill reductions discussed in the previous sections are made possible by projected changes in the underlying cost structures. These changes, discussed in terms of overall revenue requirements, are discussed below.

A utility's revenue requirement is the level of gross revenue that enables it to cover all of its prudently incurred expenses and allows it the opportunity to earn a fair return on its invested capital. The major cost elements that contribute to the total revenue requirement include:

- Fuel expense
- Purchased power expense
- Operations and maintenance expense
- Depreciation expense
- Interest expense
- Taxes (revenue and income)
- Return on equity investment

Each revenue requirements is discussed in greater detail below.

Projected Revenue Requirements

As illustrated in Figure 6-7, the total O'ahu revenue requirement increases slightly from 2014 to 2023 in real terms, and then decreases significantly from 2024 forward, such that total revenue requirements are declining in real terms over the 2014 through 2030 period.

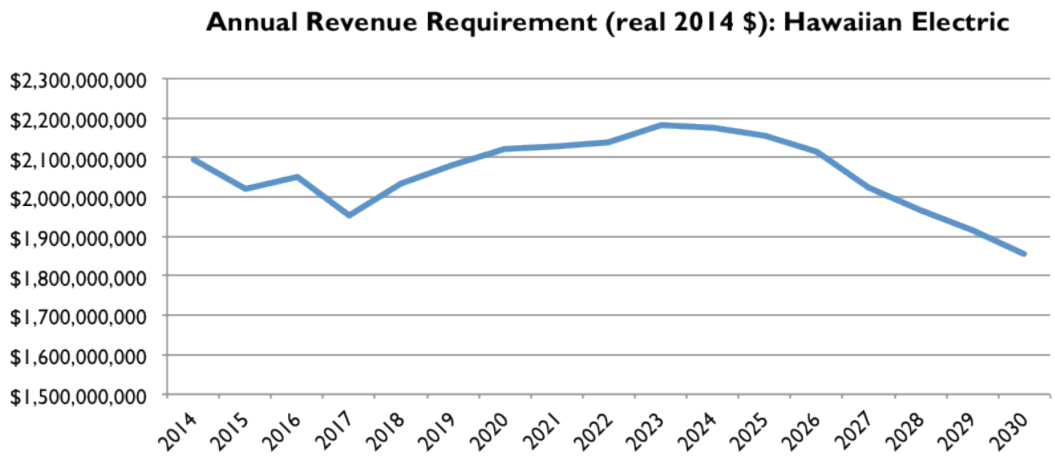

Figure 6-7. O'ahu Annual Revenue Requirement

The balance of this section explores the drivers of the changes in total revenue requirements.

To understand the drivers of the long-term reductions in revenue requirements in real terms, as well as the drivers of the near term increases, Figure 6-8 provides a breakdown of the annual revenue requirement into its major components.

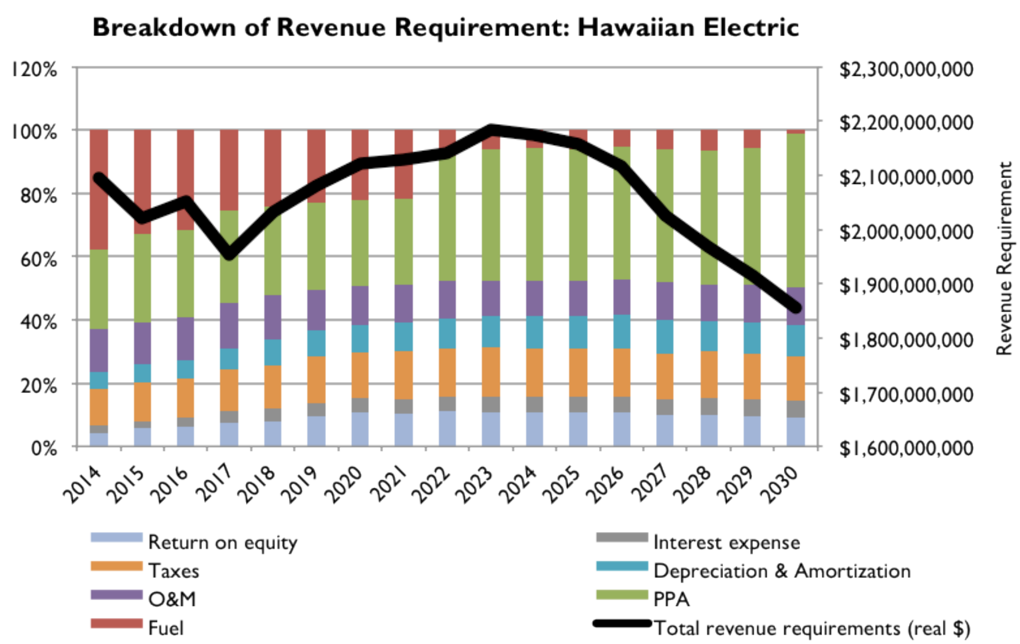

Figure 6-8. O'ahu Annual Revenue Requirement by Major Component

Fuel expense declines significantly over the period, driven by the continued shift toward renewable generation and the cost savings from the introduction of LNG, beginning in 2017.

Power Purchase Agreement costs increase over the period, reflecting both the expanding purchases of renewables and the capacity costs for replacement dispatchable generation.

O&M declines in real terms across the period, driven by the reductions in costs associated with Smart Grid and information technology investments.

Depreciation expense grows over the period, driven by both the transformational and foundational investments in the grid and the costs associated with retirement of most existing generating units.

Interest expense grows over the period, driven primarily by higher levels of investment.

Tax expense, including revenue and income tax, increases over the period, driven in part by increased income tax expense associated with the increased equity investment. The excise taxes associated with the significant transformational and foundational investments to be made by the Company and others over the 2015–2025 period will be significantly higher than excise taxes associated with Company activities over the 2010–2014 period. The impact of this higher level of tax payments is reflected in the total cost of the new capital investments and is included in the PPA, depreciation, and return on capital cost elements in Figure 6-9. The corresponding state tax credit is amortized over 48 years and so the benefit is only partially realized in the forecast period.

The growth in *return on equity investments* and, as mentioned above, the interest expense, is driven by the capital investment profile of foundational and transformational investments, shown in Figure 6-9.

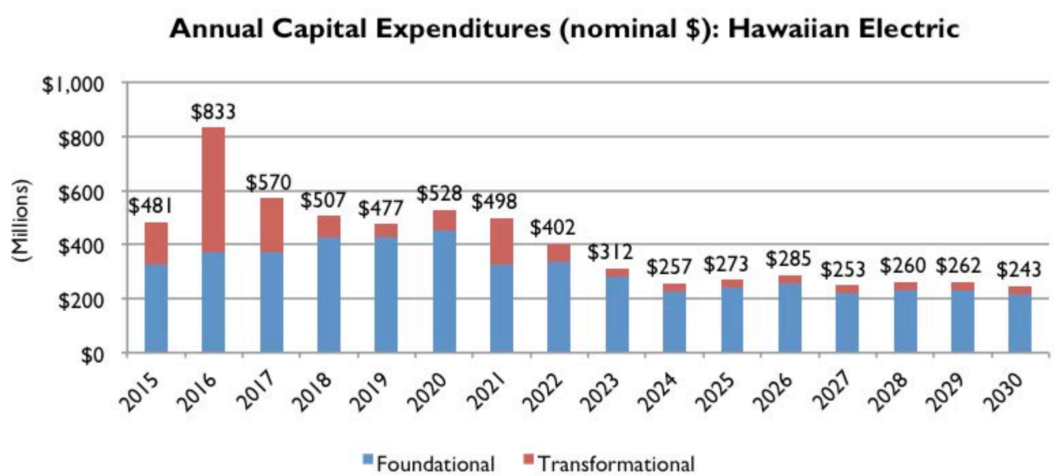

Figure 6-9. O‘ahu Foundational and Transformational Capital Expenditures by Year

This profile reflects the basic fact that transformational investments need to be made in advance of each of major changes to the O‘ahu grid. The LNG transportation, re-gasification, and unit modification investments must be made to enable the LNG fuel savings. Rapid reacting contingency storage and other grid enhancements are necessary to ensure system reliability with current levels of DG-PV, as well as being required to enable DG-PV growth over the next five to seven years. Replacement dispatchable resources must be built or sourced in advance of any additional unit deactivations and retirements. Smart Grid capabilities must be built to enable dynamic pricing.

Securitization

One tool that can help reduce the revenue requirement would be the use of a securitization mechanism to deal with retired generating units. This technique has been widely used elsewhere in the industry to deal with stranded costs.[54] One way it could be applied in Hawai‘i to lower revenue requirements and lower costs to our customers would be to re-finance upon retirement the net book value of a generating unit, plus any un-accrued for removal costs, fully with securitized debt. The cash flow to repay the debt would come from a specially designated, non-bypassable customer charge. Figure 6-10 shows the revenue requirement reduction that can be achieved through securitization, assuming it was re-financed at 5% and repaid over 20 years, for each of the units planned to be retired through this PSIP.

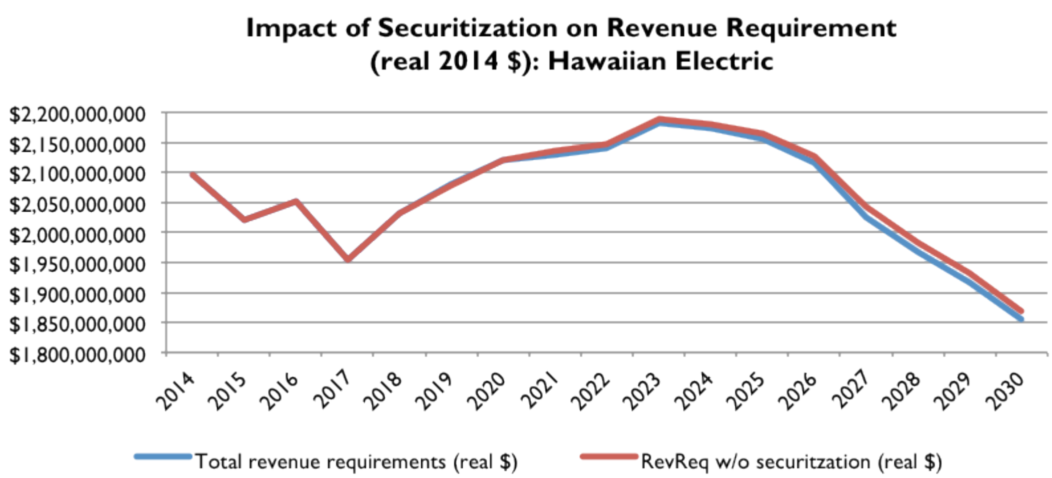

Figure 6-10. Impact of Securitization on Projected O‘ahu Revenue Requirement

Given that retirement of existing generation is a key policy objective and that there has been acknowledgement of the need to deal with stranded costs by both the legislature and the Commission, the Company believes that planning for the availability of this tool is reasonable. Therefore, the customer bill impact analysis presented at the start of this

[54] Including states such as Texas, Pennsylvania, and New Jersey among many others.

chapter assumes that the projected revenue requirement has been reduced by securitization, as shown in Figure 6-10 above.

CONCLUSION

The PSIP identifies those transformational and foundational investments required to build the necessary flexible, smart, and renewable energy needed to reliably serve customers across Oʻahu. Under the current rate design, while electricity bills for average full service residential customers will increase in the short-run, by 2030, electric bills will be reduced by 16% in real terms from 2014 levels under the current tariff structure and by 22% under DG 2.0.

7. Conclusions and Recommendations

Hawaiian Electric, Maui Electric, and Hawai‘i Electric Light are pleased to present their Power Supply Improvement Plans (PSIPs).

CONCLUSIONS

1. **Renewable Portfolio Standard (RPS).** Hawai‘i's policy goals will be achieved due to unprecedented levels of renewable energy on each island by 2030.
   - **a.** For the Hawaiian Electric Companies, the consolidated renewable content of electricity increases to approximately 67%.
   - **b.** Hawai‘i Electric Light's PSIP increases renewable content of electricity for Hawai‘i Island to approximately 92%.
   - **c.** Maui Electric's PSIP increases renewable content of electricity for Maui County to approximately 72%.
   - **d.** Hawaiian Electric's PSIP increases renewable content of electricity for O‘ahu to approximately 61%.
2. **Customer Bill Impact Is Beneficial.** The Preferred Plan coupled with changes in rate design that more fairly allocates fixed grid costs across all customers (assumed effective in 2017) is expected to reduce monthly bills for average residential customers from 2014 to 2030 by:
   - **a.** 28% for Maui Electric
   - **b.** 30% for Hawai‘i Electric Light
   - **c.** 22% for Hawaiian Electric

3. **Distributed Solar PV.** For all three operating companies, the PSIP will result in a nearly three-fold increased in solar distributed generation (DG-PV).
4. **Demand Response.** The PSIP will utilize the demand response programs defined in the Companies recently issued *Integrated Demand Response Portfolio Plan* (IDRPP)[55] as integral tools for system operations, and to provide ways for customers to save money on their electric bills by reducing their usage at certain times.
5. **Energy Storage.** The Companies will utilize energy storage system for multiple purposes, and maximize the utilization of renewable energy that is available on the power systems. Storage will be used as "fast-responding" regulating and contingency reserves for system operation.
   a. "Load-shifting" energy storage, including pumped storage hydro and flow batteries, are not currently cost-effective and are not included in our Preferred Plan. In the future, this type of energy storage may prove to be cost-effective and beneficial.
6. **Liquefied Natural Gas (LNG).** LNG play a critical role in the Preferred Plans for all three operating companies, providing for significant cost savings, environmental compliance, and enhanced operational flexibility.
7. **High Utilization of Renewable Energy Resources.** The available energy from renewable resources will be utilized at extremely high levels from 2015 through 2030. This is accomplished by installing energy storage to provide regulating and contingency reserves, using demand response as a tool for better managing system dispatch, selecting future thermal generation resources that have a high degree of operational flexibility, increasing the operational flexibility of existing thermal generation not slated for retirement during the study period, and reducing the "must-run" requirements of thermal generators. The following annual amounts of renewable energy will be utilized (not curtailed) annually:
   a. Maui Electric achieves at least 97.0%
   b. Hawai'i Electric Light achieves at least 96.1%
   c. Hawaiian Electric achieves at least 97.3%
8. **Diverse Generation Resource Mix.** Achieving unprecedented levels of renewable energy, reliable electric service, high utilization of available renewable energy depends on a diverse mix of generation resources and energy storage systems, and judicious use of demand response programs.

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[55] The Companies filed their IDRPP with the Commission on July 28, 2014.

9. **Role of Thermal Generation.** Firm and dispatchable thermal generators provide a critical role complementing the renewable energy resources in the generation mix, including a provision of critical grid services for system reliability, and back-up generation for when variable renewable resources are unavailable (for example, hours of darkness, extended cloudiness, or absence of wind).

10. **Retirement of Existing Oil-fired Steam Generators.** During the PSIP planning period of 2015–2030, all of the existing oil-fired steam generators will be retired, or converted to LNG and then retired, including:
    - **a.** Maui Electric: Kahului Units 1–4
    - **b.** Hawai‘i Electric Light: Hill Units 5 & 6 and Puna Steam
    - **c.** Hawaiian Electric: Kahe Units 1–6 and Waiau Units 3–8

11. **O‘ahu–Maui Grid Tie.** A grid tie connecting the electric grids of O‘ahu and Maui would not be cost effective.

RECOMMENDATIONS

We recommend that the Commission, interveners, and participants in Docket 2014-0183, carefully consider the thoughtful and thorough analyses presented in this PSIP. We commit to an honest and thorough discussion of the matters discussed herein.

In the meantime, there are certain initiatives that are already underway that are integral parts of the Preferred Plan. In particular, we will continue to work with stakeholders to address distributed generation interconnection requirements in order to realize the aggressive DG-PV goals included in the Preferred Plan, and as outlined in the *Distributed Generation Interconnection Plan* (DGIP) filed concurrently with this PSIP. All of the ongoing initiatives are the subject of existing docketed proceedings before the Commission. We will continue to move forward with those initiatives as directed by the Commission.

We pledge to work collaboratively with key stakeholders during the regulatory review process so that together, we will achieve success in the transformation outlined in this PSIP.

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