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.

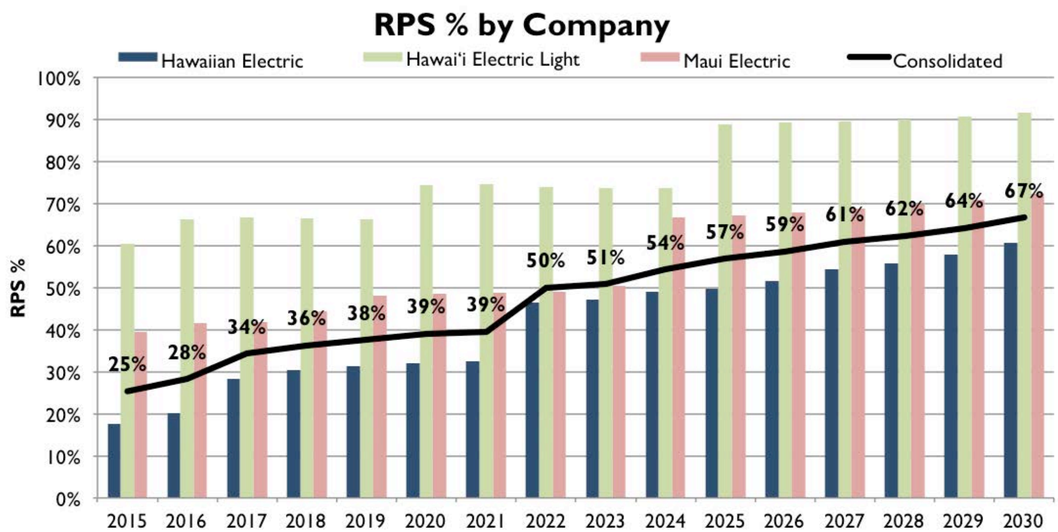

Figure ES-1. Renewable Portfolio Standard (RPS) for the Hawaiian Electric, Maui Electric, Hawai‘i Electric Light, and the Consolidated Companies, 2015–2030.

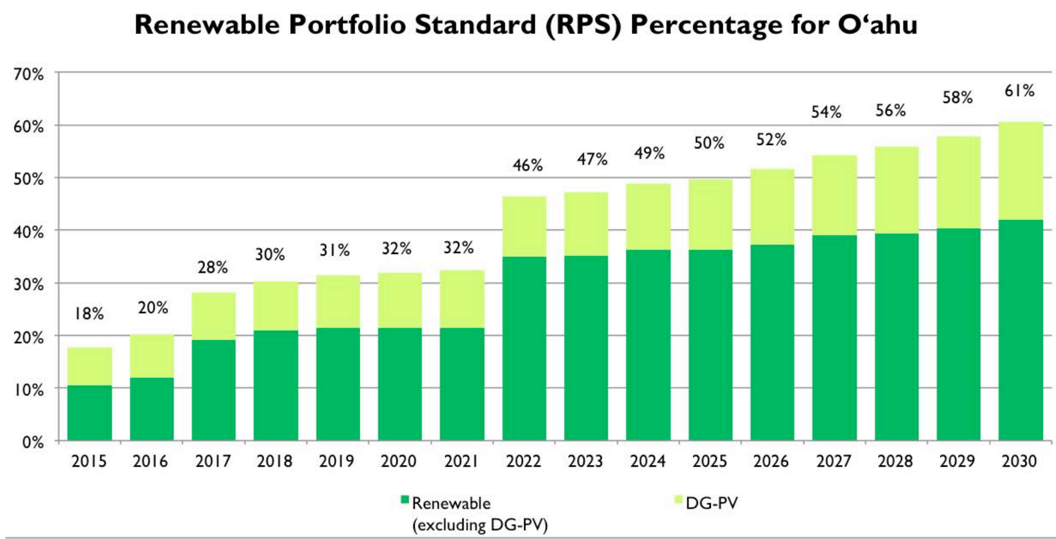

Figure ES-2. Renewable Portfolio Standard (RPS) for Hawaiian Electric on O'ahu, 2015-2030, showing the relative contribution from distributed generation (DG-PV)

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.

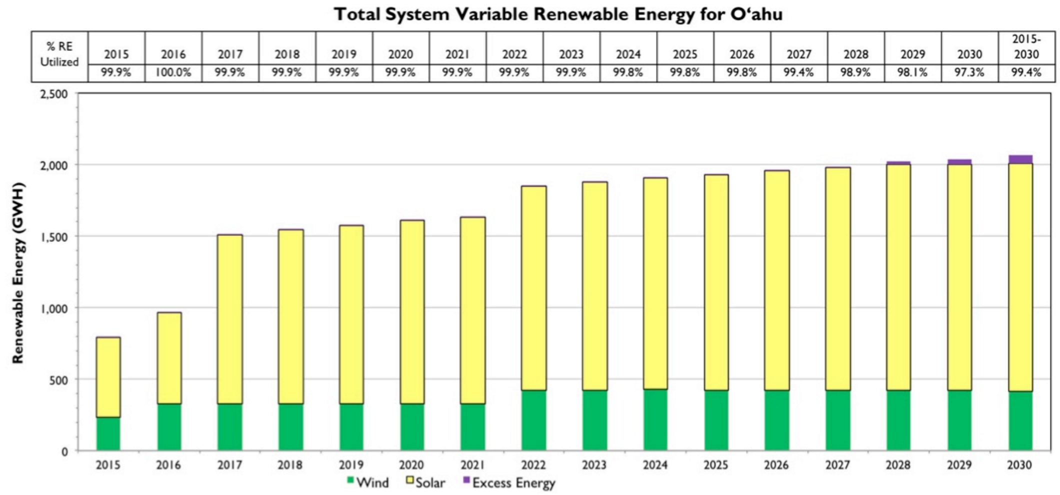

Figure ES-3. Total System Variable Renewable Energy Utilized by Hawaiian Electric

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.

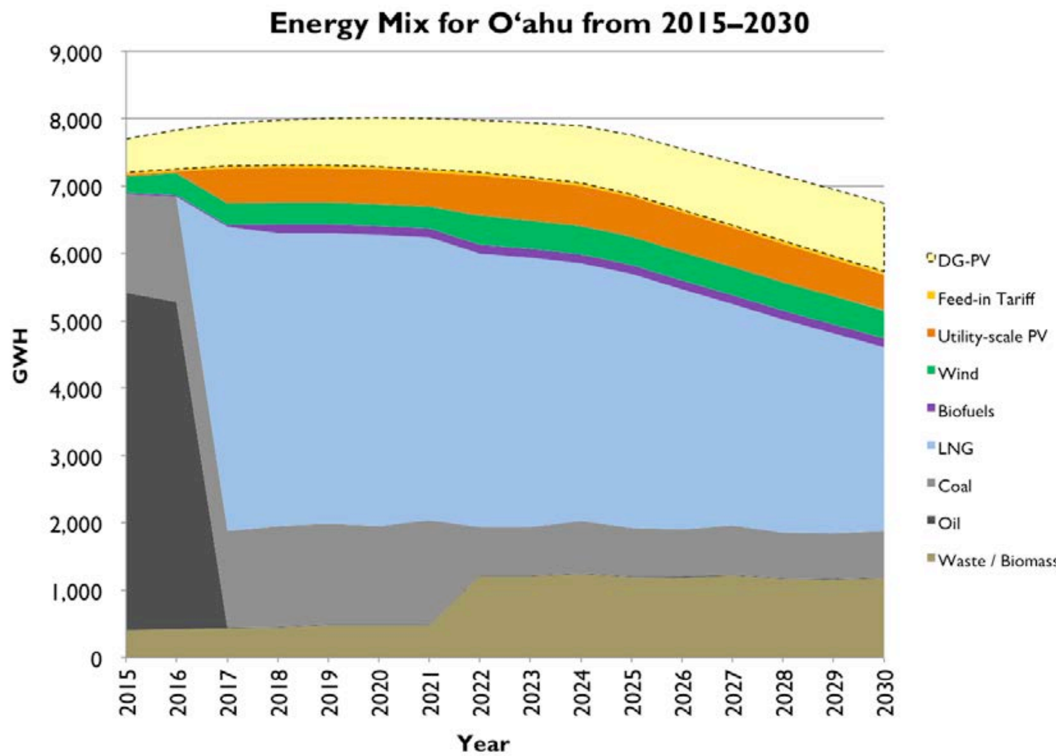

Figure ES-4. Annual Energy Mix of Hawaiian Electric Preferred Plan

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 Hawaiʻi 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 Oʻahu 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).

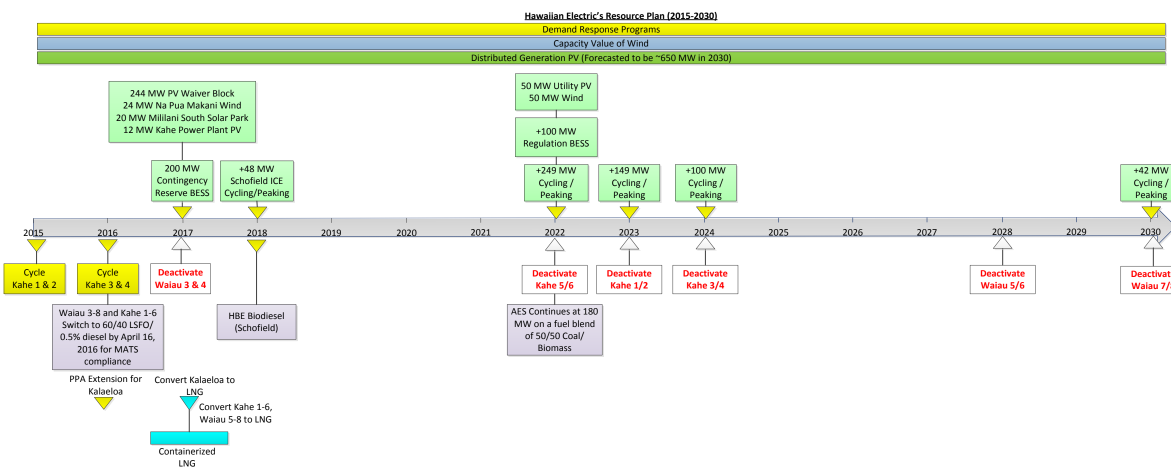

Figure ES-5. Hawaiian Electric Preferred Plan 2015–2030

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 Hawaiʻi'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 Oʻahu 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).

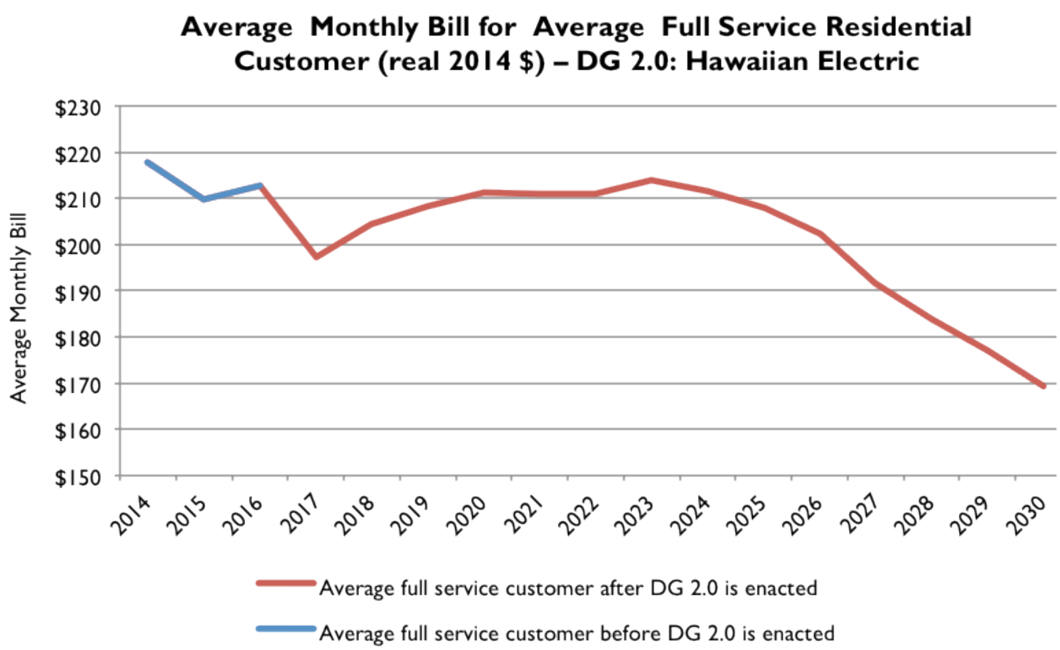

Figure ES-6. Average Full Service Residential Customer Bill Impact

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 Oʻahu 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 Oʻahu, but is also relevant for the Maui Electric and Hawaiʻi Electric Light power systems.

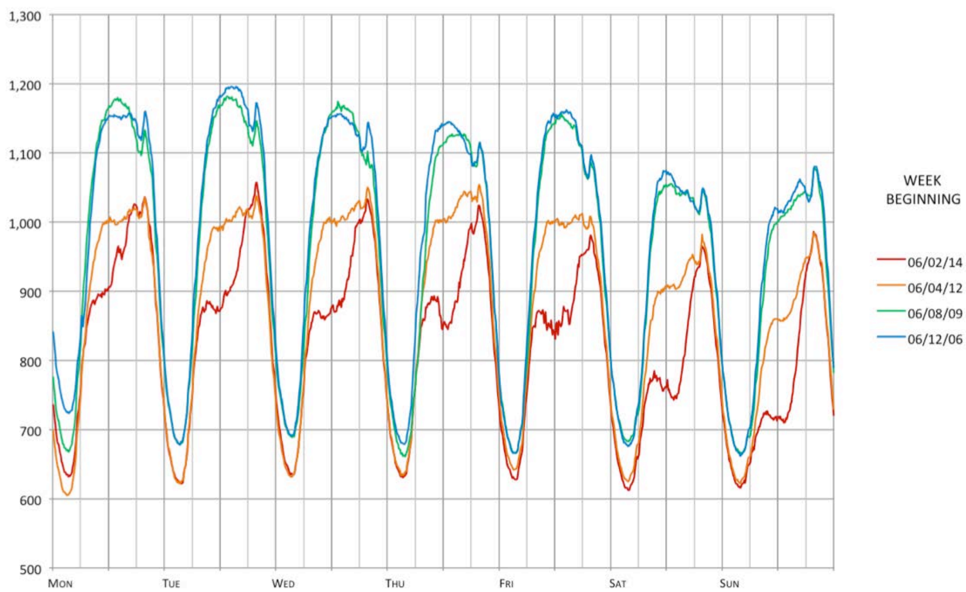

Figure 1-7. Oʻahu System Load Profiles, 2006–2014

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

- Daytime peak loads on the Oʻahu 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.

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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 Hawai‘i. 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 Hawai‘i.

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

Our vision is to deliver affordable, 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

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COMMON OBJECTIVES

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

We share the Hawai‘i 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 Hawai‘i, 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.** Hawai‘i 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 Hawai‘i's remoteness and lack of interconnections, we must have an

[3] See "Commission's Inclinations on the Future of Hawai‘i'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 Hawaiʻi economy.** We will contribute to the health and diversity of Hawaiʻi'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

[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.**

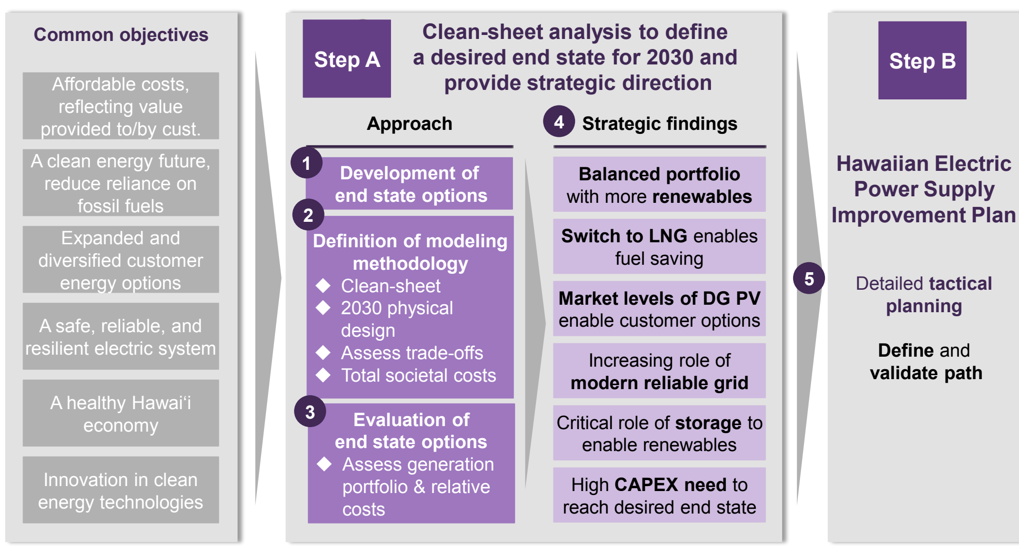

Figure 2-1. Approach to Define Desired Physical System Design 2030 End-State

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

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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.

[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.

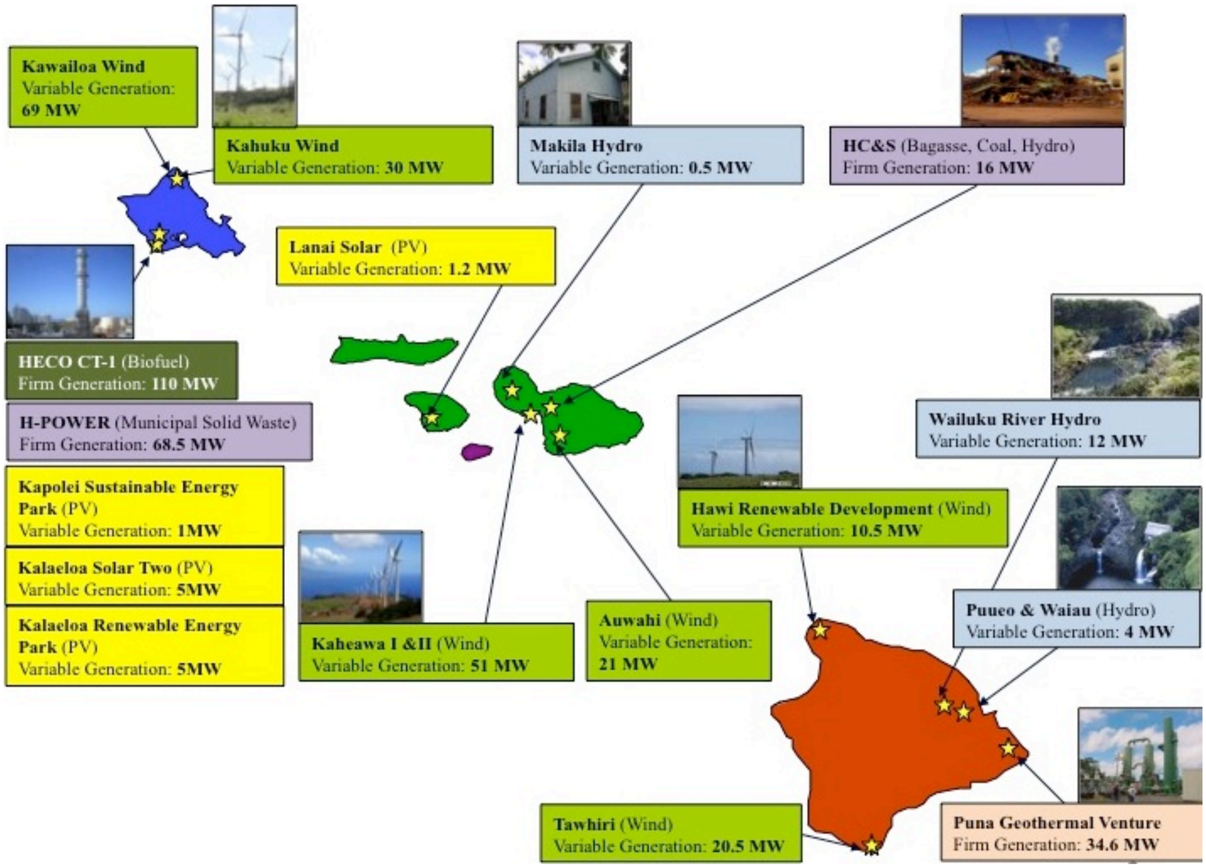

Figure 3-1. Current Clean Energy Resources

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%.

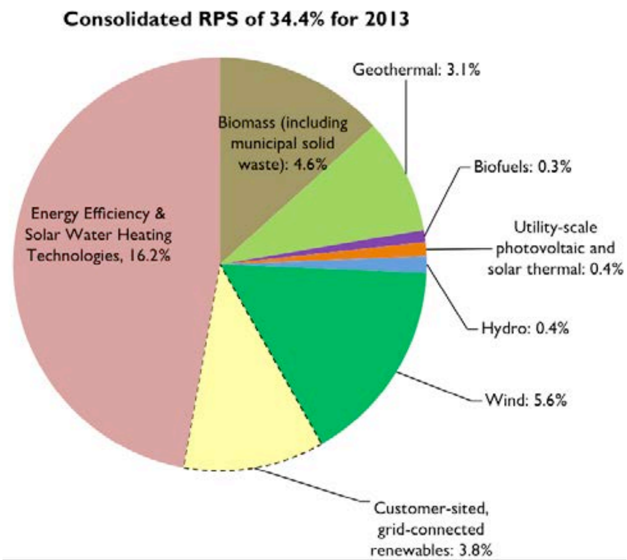

Figure 3-2. Consolidated RPS of 34.4% for 2013

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).

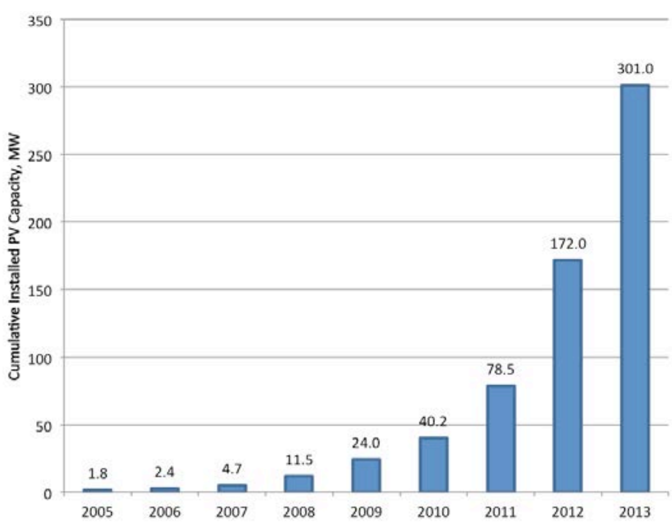

Figure 3-3. Photovoltaic Generation Growth: 2005 through 2013

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. O‘ahu 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.

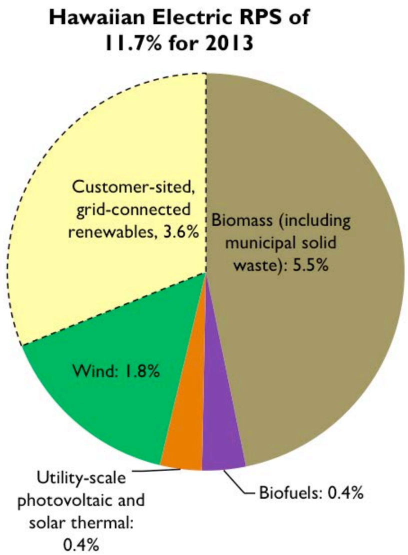

Figure 3-4. 2013 Hawaiian Electric RPS Percent for 2013

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.

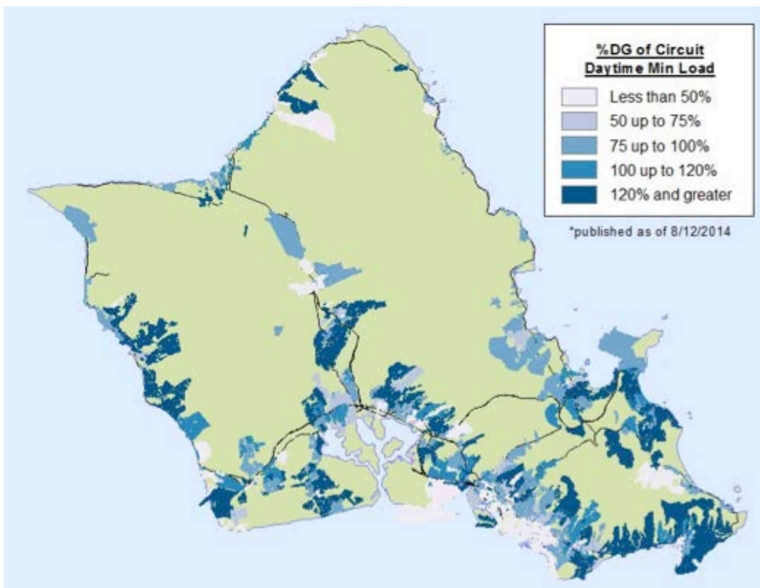

Figure 3-5. Distributed Generation Map of O'ahu

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 Hawai‘i 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). Hawai‘i is a pioneer in OTEC research, having demonstrated the first successful OTEC project on Hawai‘i 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 O‘ahu. 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 Hawai‘i. 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.

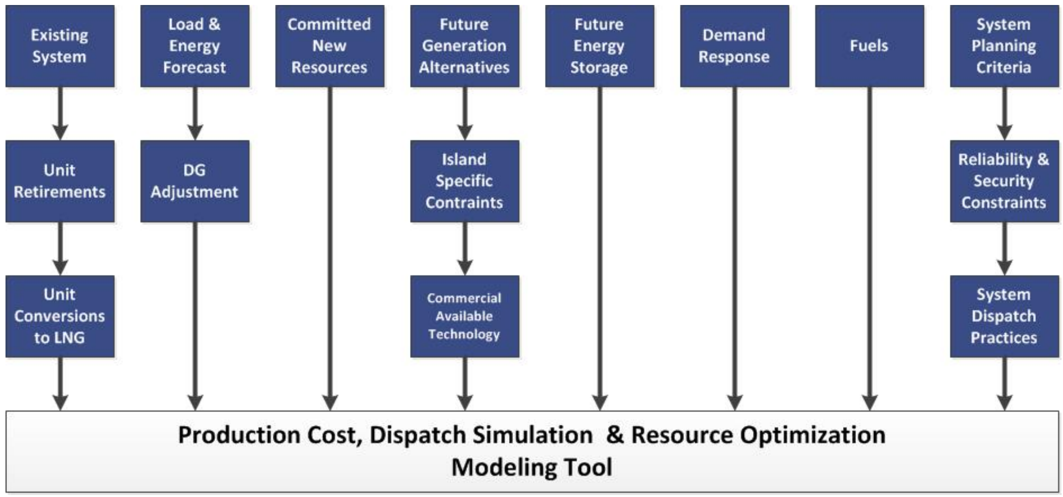

Figure 4-1. PSIP Production Simulation Model Input Hierarchy

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

- Ma'alea 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.

Hawai'i 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 Hawaiʻi 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.

Hawaiʻi 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 Oʻahu. 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, Oʻahu. 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.

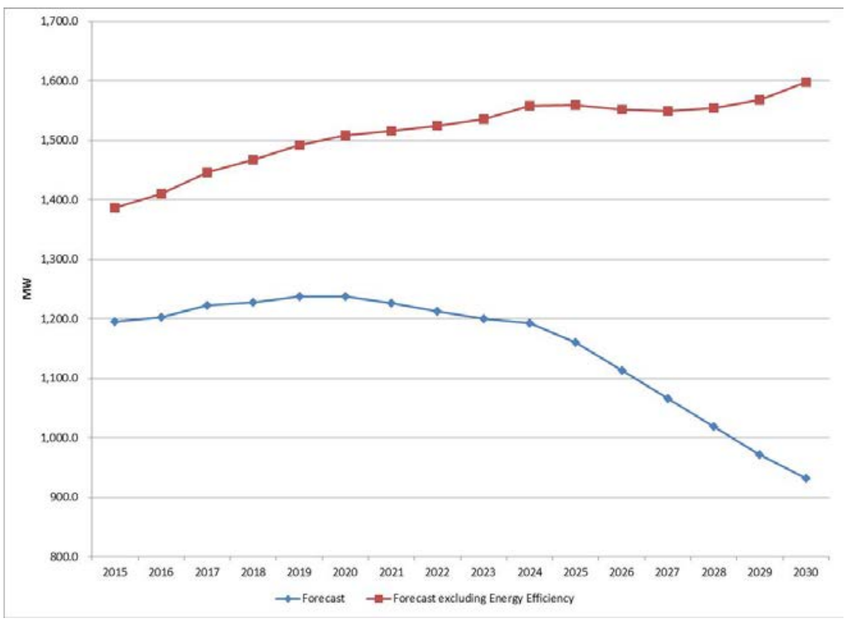

Figure 4-2. Hawaiian Electric Peak Demand Forecast (Generation Level)

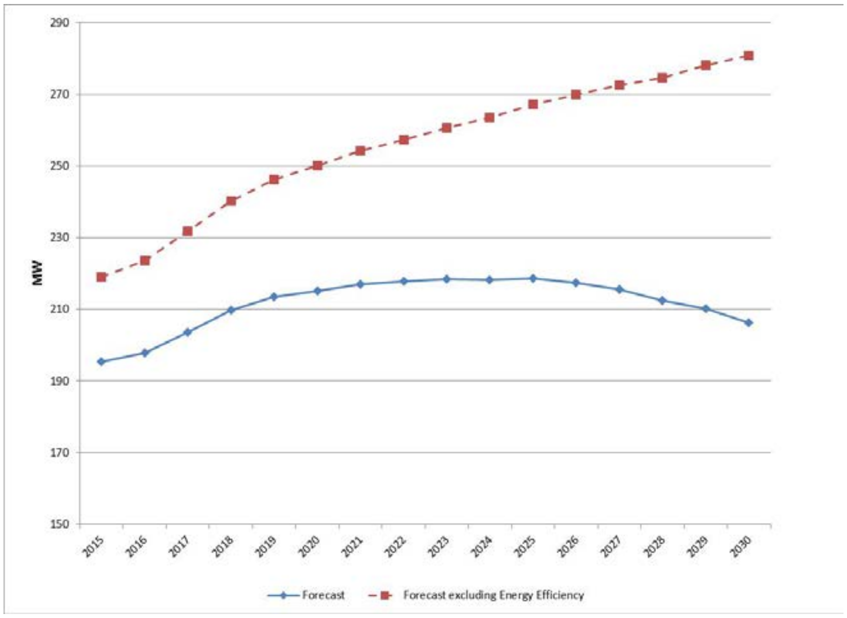

Figure 4-3. Maui Peak Demand Forecast (Generation Level)

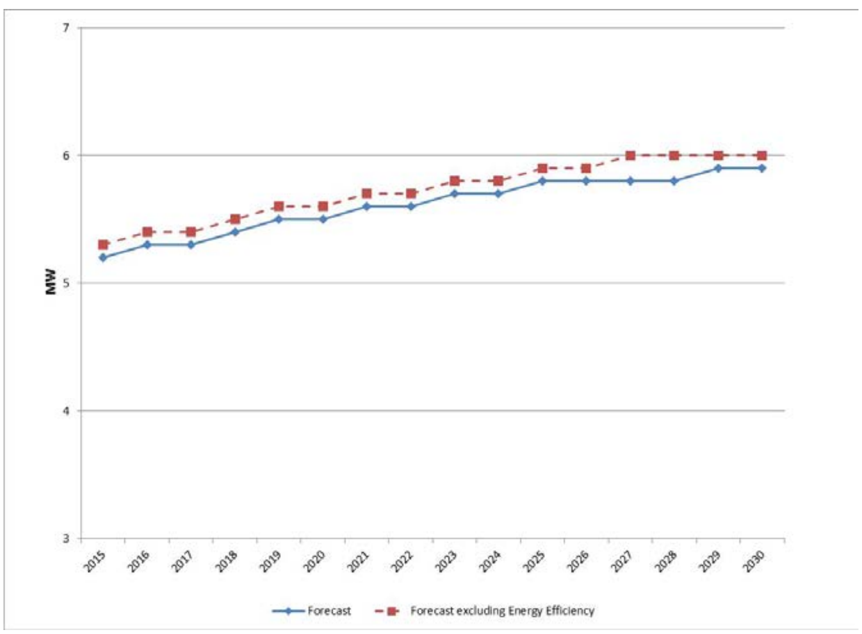

Figure 4-4. Lana'i Peak Demand Forecast (Generation Level)

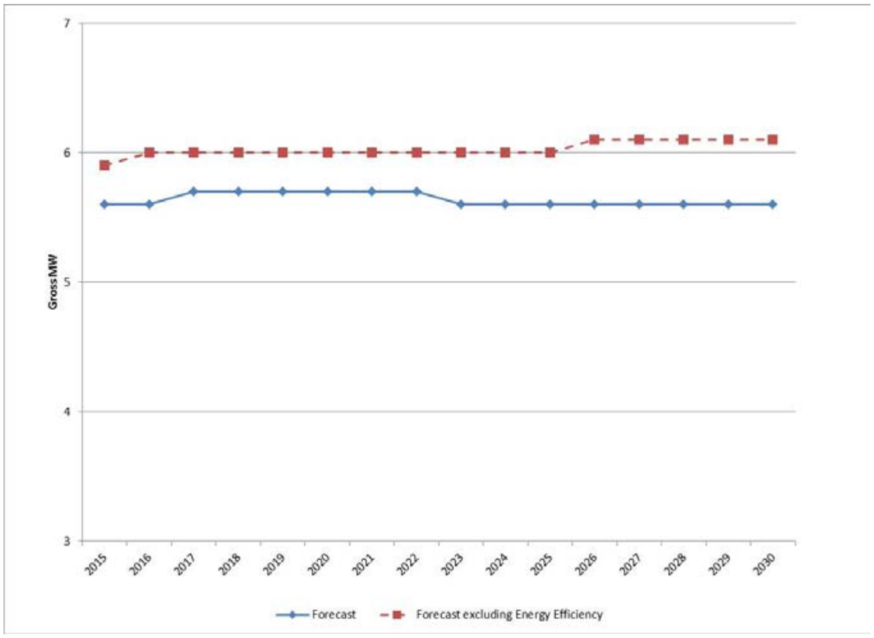

Figure 4-5. Moloka'i Peak Demand Forecast (Generation Level)

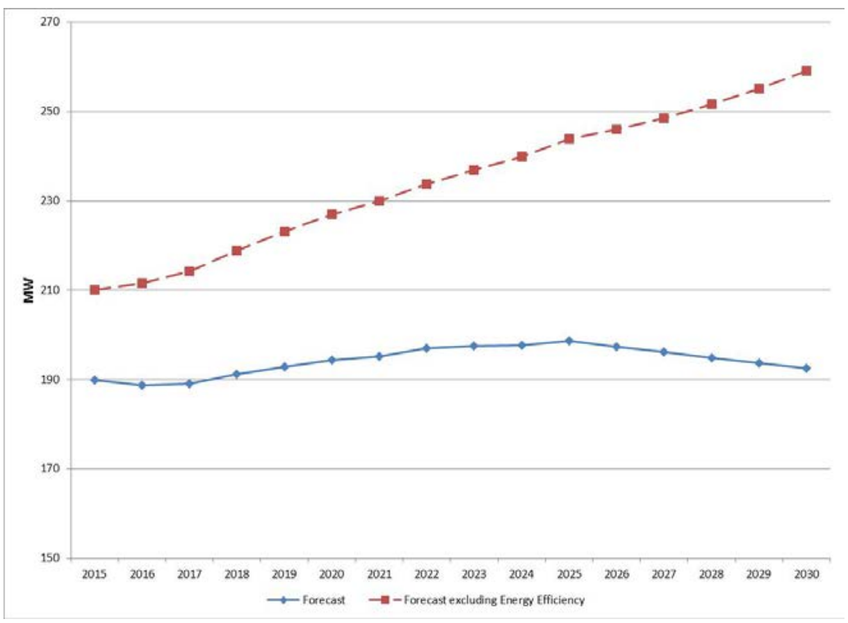

Figure 4-6. Hawai'i Electric Light Peak Demand Forecast (Generation Level)

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.

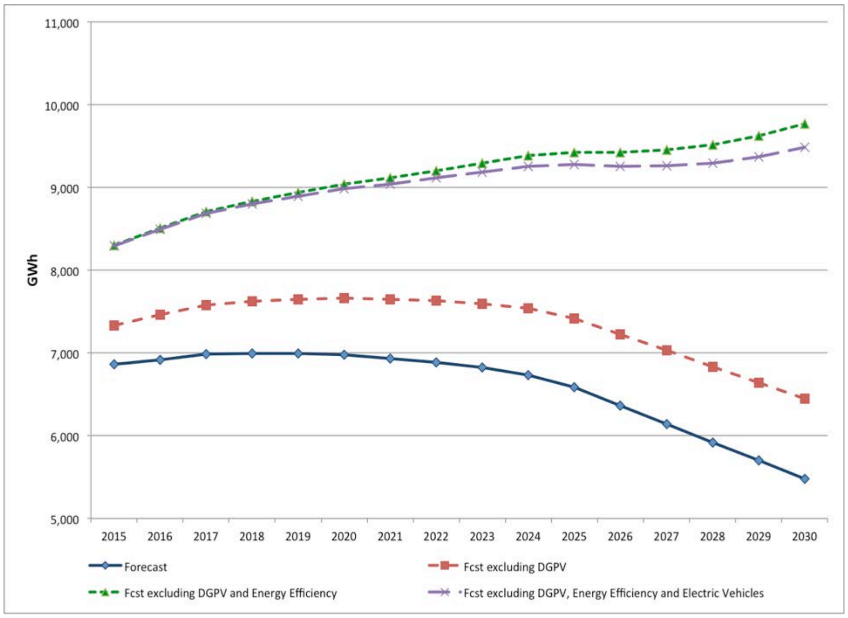

Figure 4-7. Hawaiian Electric Energy Sales Forecast (Customer Level)

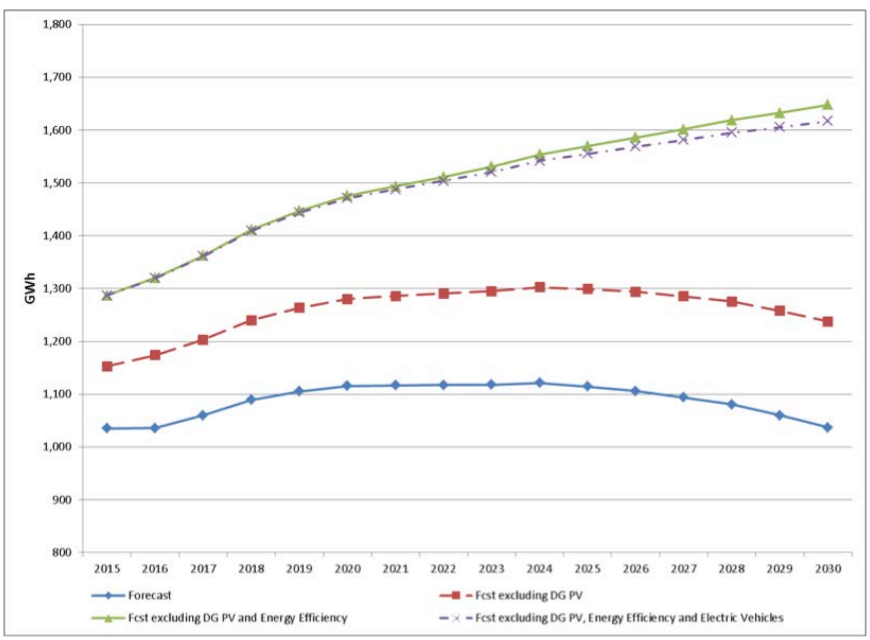

Figure 4-8. Maui Energy Sales Forecast (Customer Level)

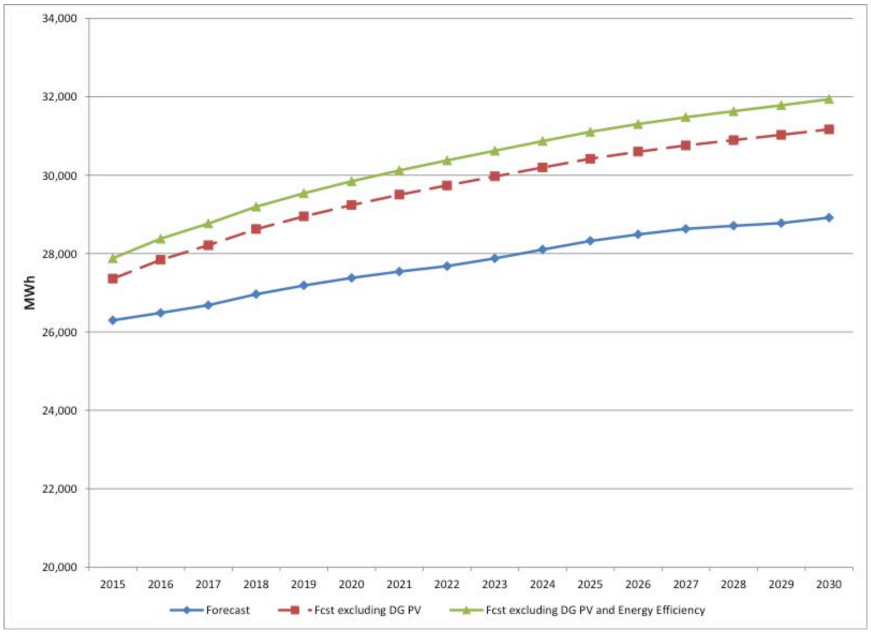

Figure 4-9. Lana'i Energy Sales Forecast (Customer Level)

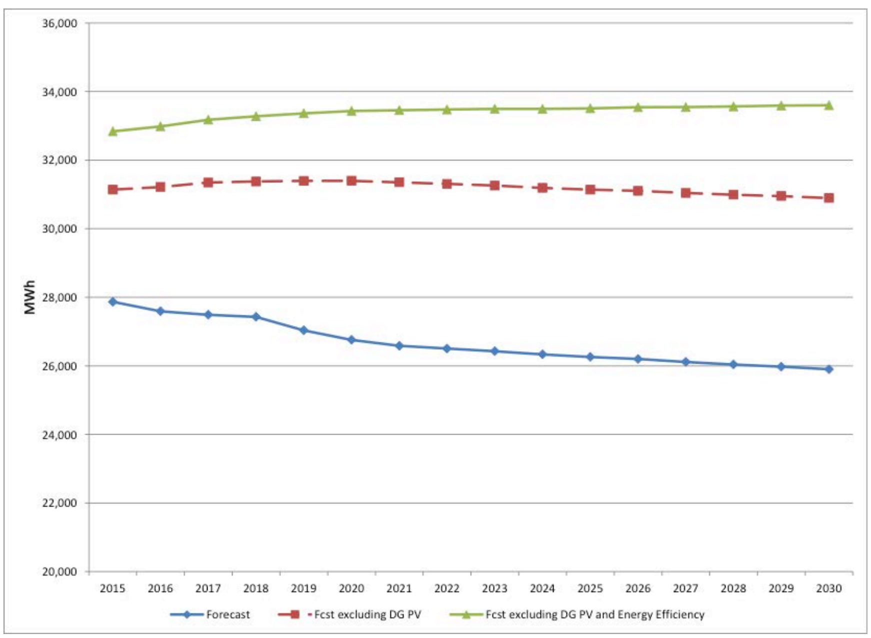

Figure 4-10. Moloka'i Energy Sales Forecast (Customer Level)

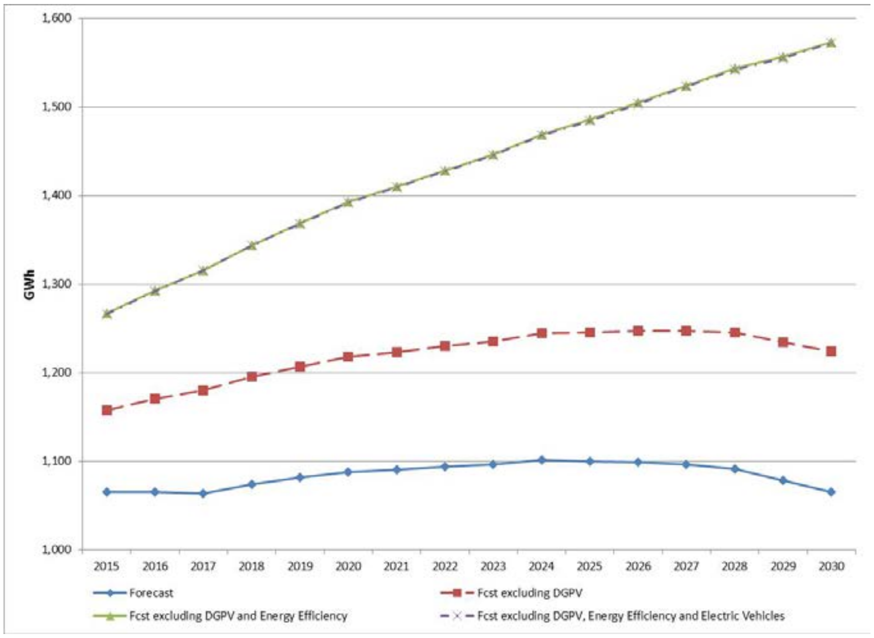

Figure 4-11. Hawai'i Electric Light Energy Sales Forecast (Customer Level)

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.

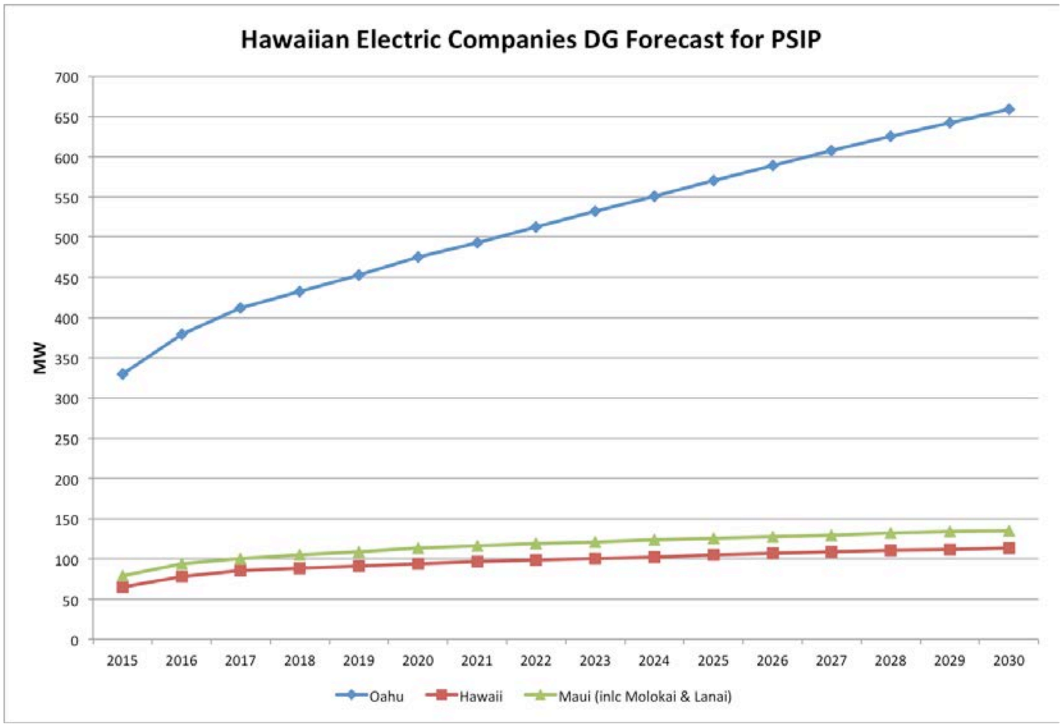

Figure 4-12. Installed DG Forecasts

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.

[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

Hawaiʻi 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.

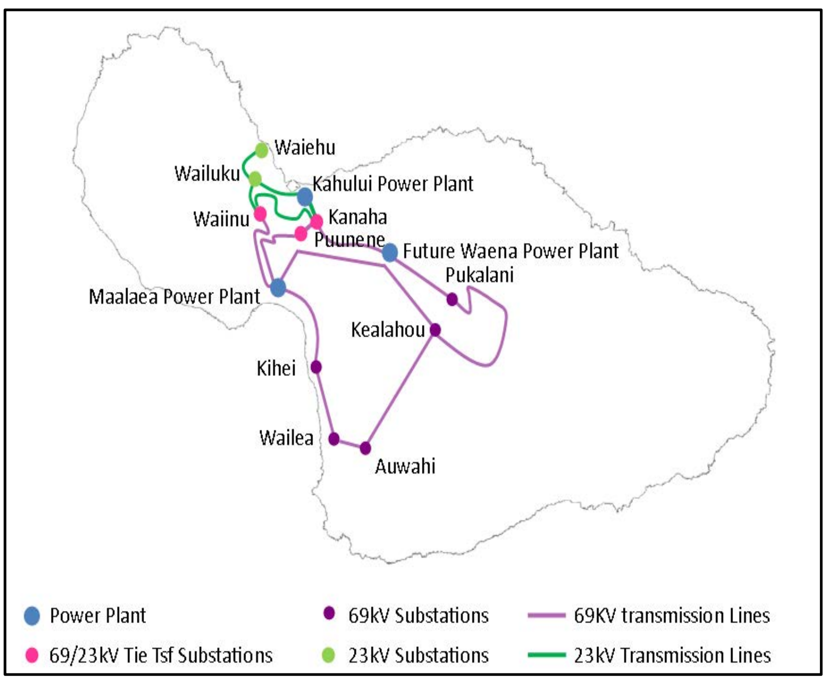

Figure 4-13. Transmission Overview for Key Maui Electric Substations Related to NTAs

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.

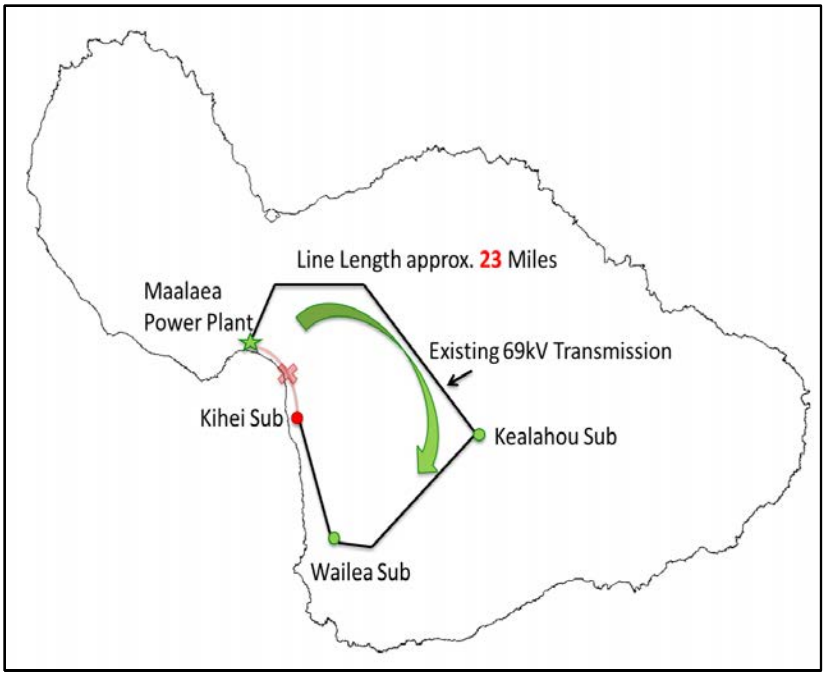

Figure 4-14. Longer Distance Required to Serve Loads in Kihei Under an N-1 Contingency

The *Maʻalaea-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 Hawai'i 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 Hawai'i) 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 Kamali'i 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

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[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.

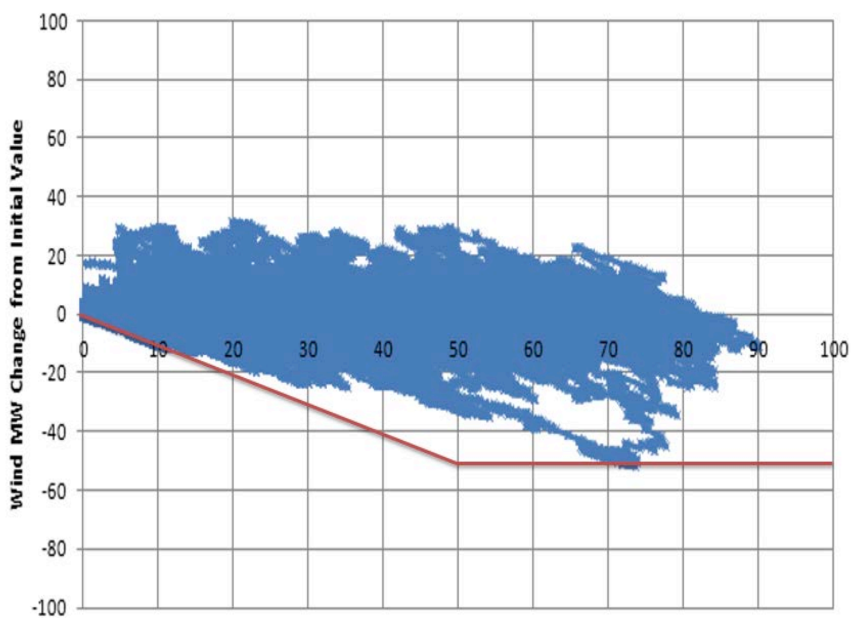

Figure 4-15. 20-Minute Scatter Plot for Hawaiian Electric Wind Generation

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.

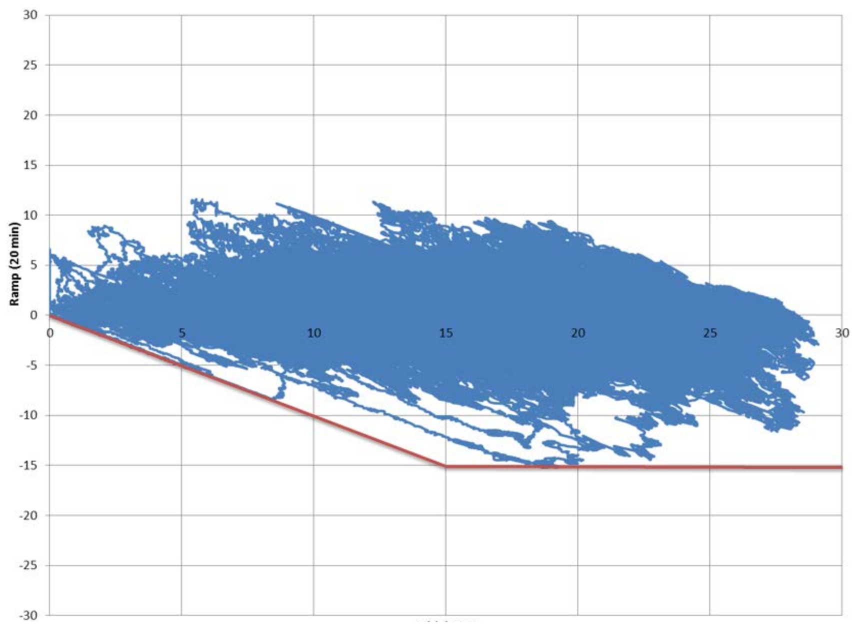

Figure 4-16. 20-Minute Scatter Plot for Hawai‘i Electric Light Wind Generation

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.

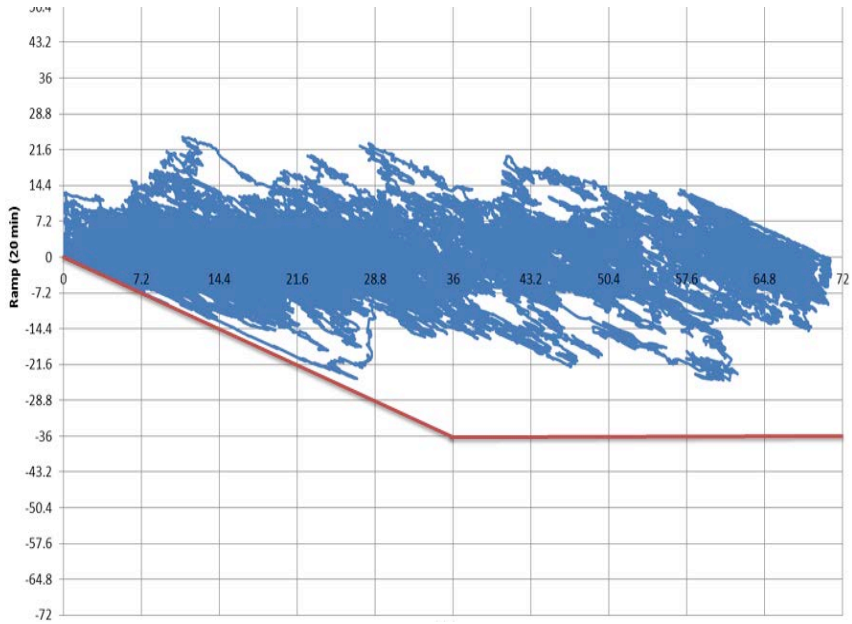

Figure 4-17. 20-Minute Scatter Plot for Maui Electric Wind Generation

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

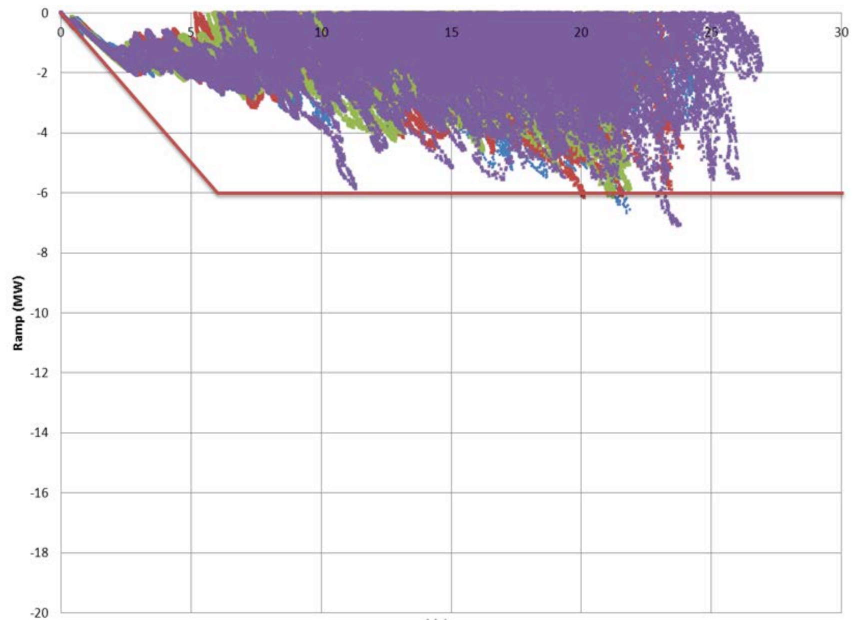

Figure 4-18. Maui Electric 20-Minute Solar Ramps

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).

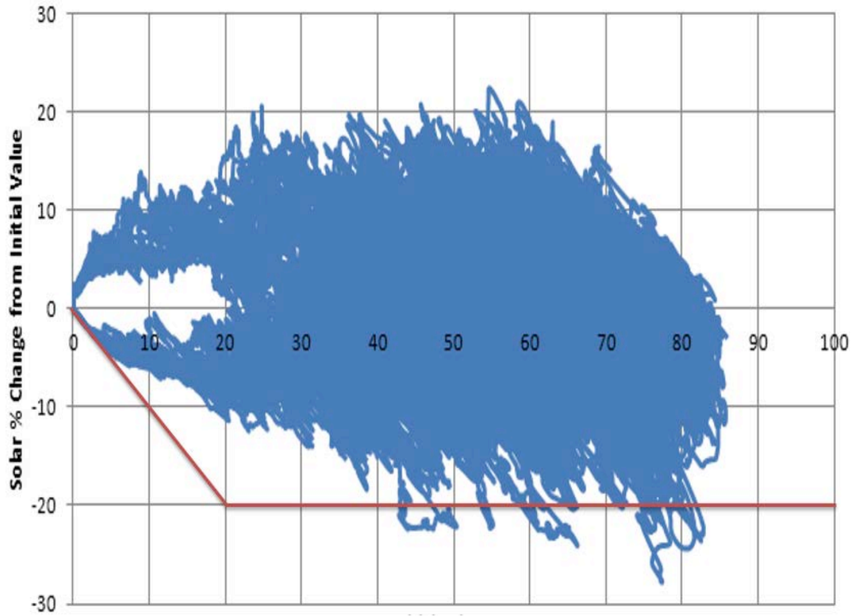

Figure 4-19. Hawai‘i Electric Light 20-Minute Solar Ramps for Half of February

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.

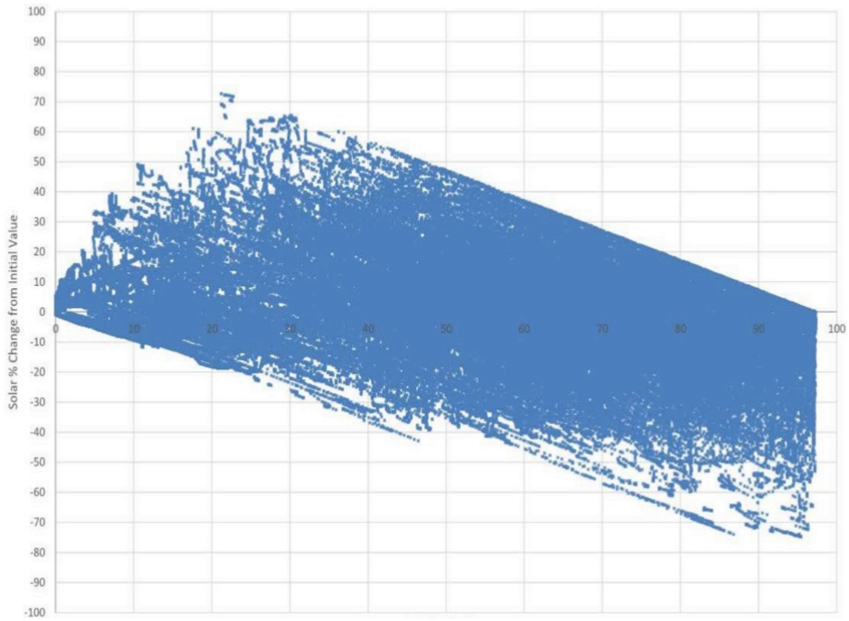

Figure 4-20. Hawaiian Electric Combined Station Class PV

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).

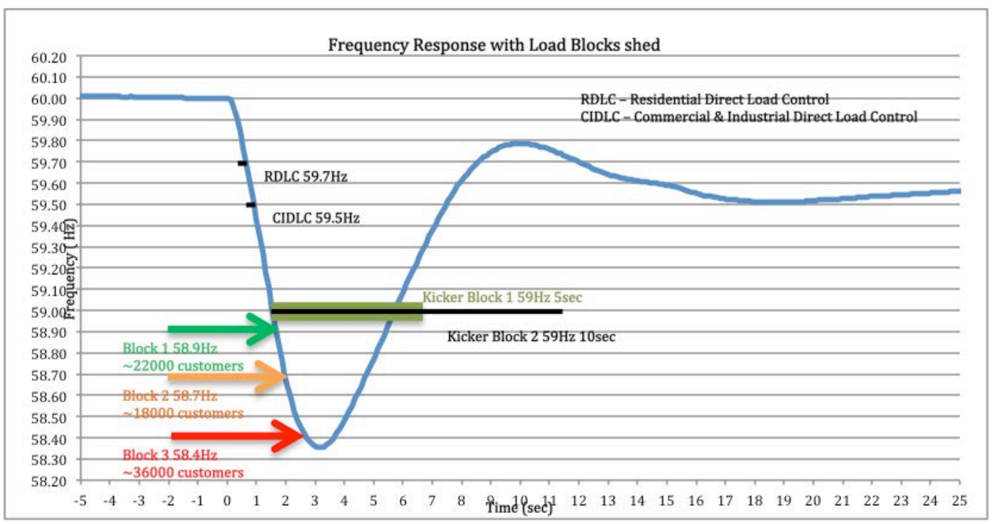

Figure 4-21. Frequency Response with Load Blocks Shed

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 + LMS1000 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.

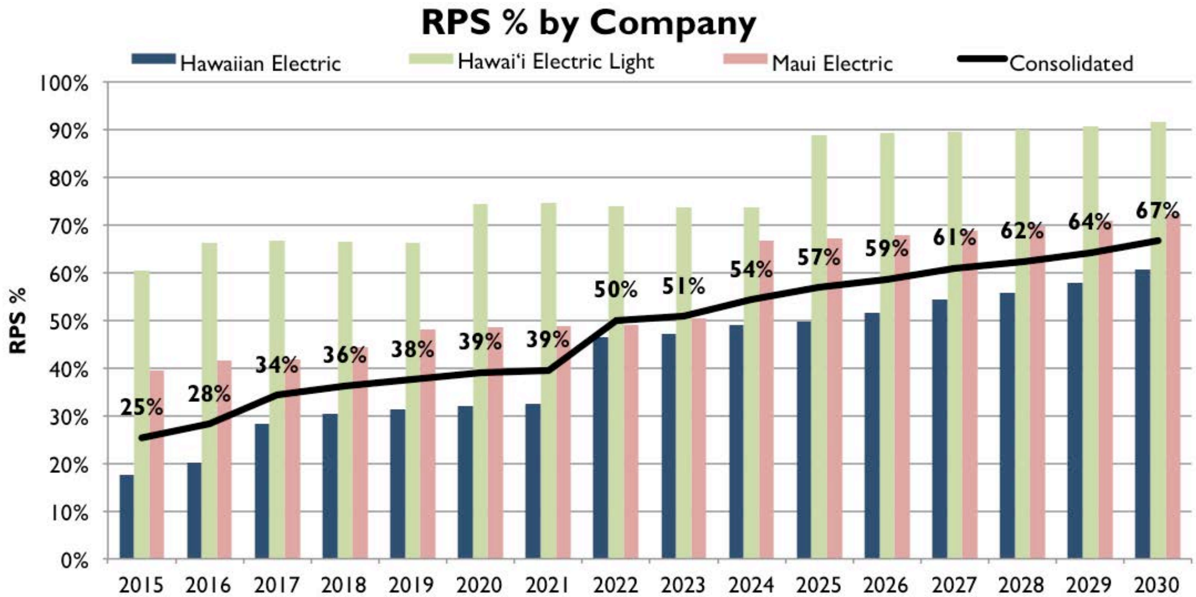

Figure 5-1. Consolidated RPS of Hawaiian Electric Companies Preferred Plans

Hawaiian Electric
Maui Electric
Hawai'i Electric Light

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.

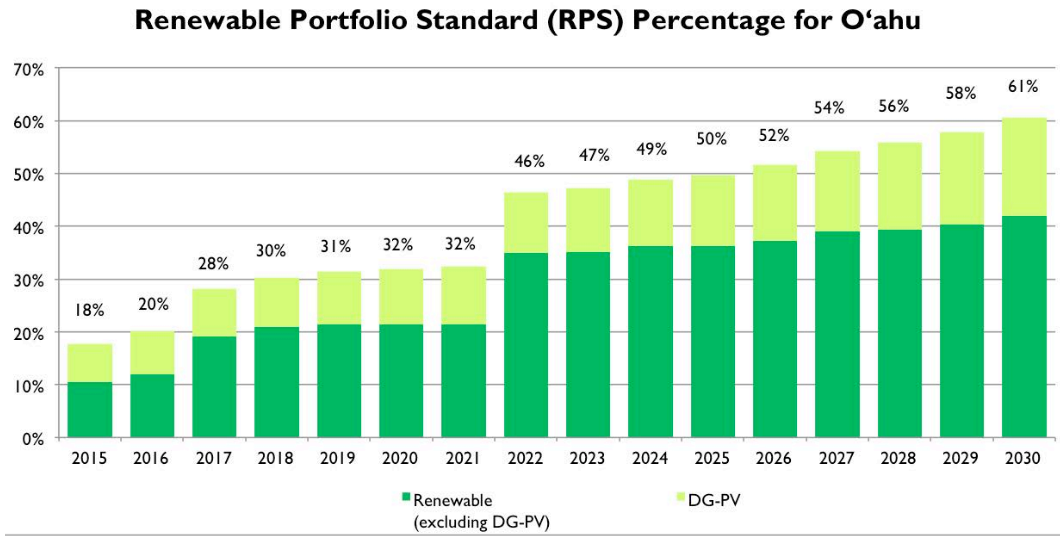

Figure 5-2. Hawaiian Electric Preferred Plan RPS on O'ahu

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%.

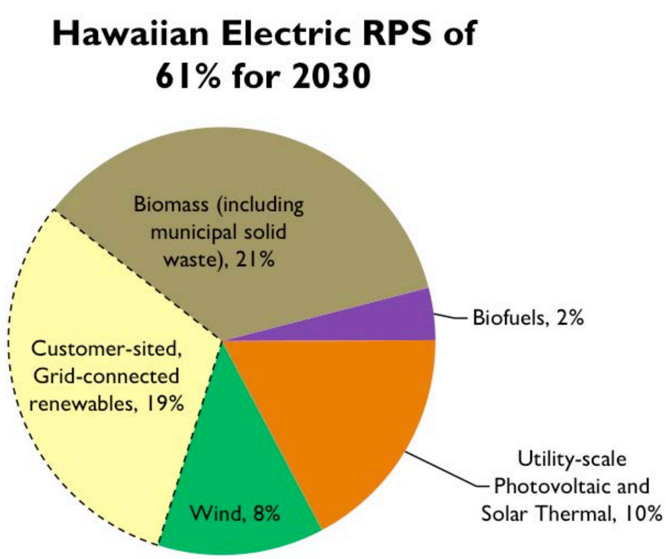

Figure 5-3. 2030 RPS for Hawaiian Electric Preferred Plan

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).

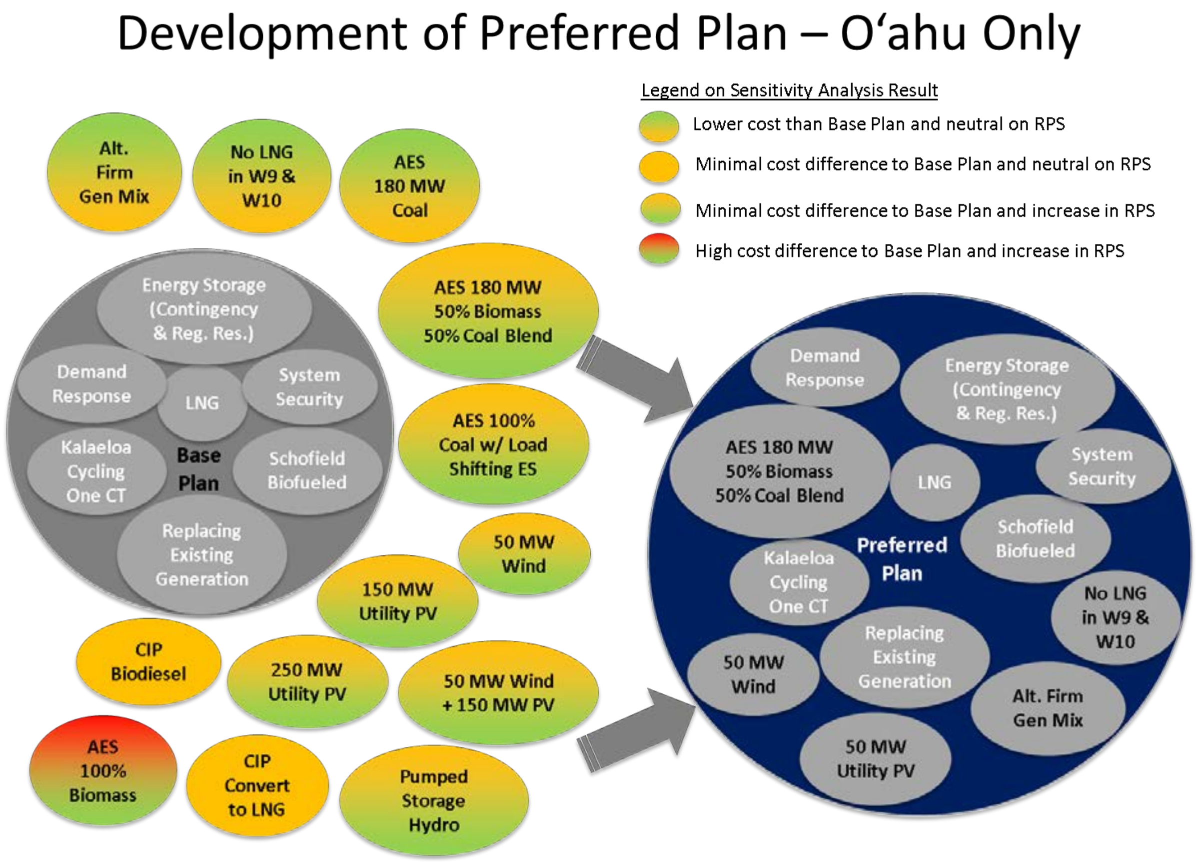

Figure 5-4. Illustration of the Process for Developing the Hawaiian Electric Preferred Plan

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.

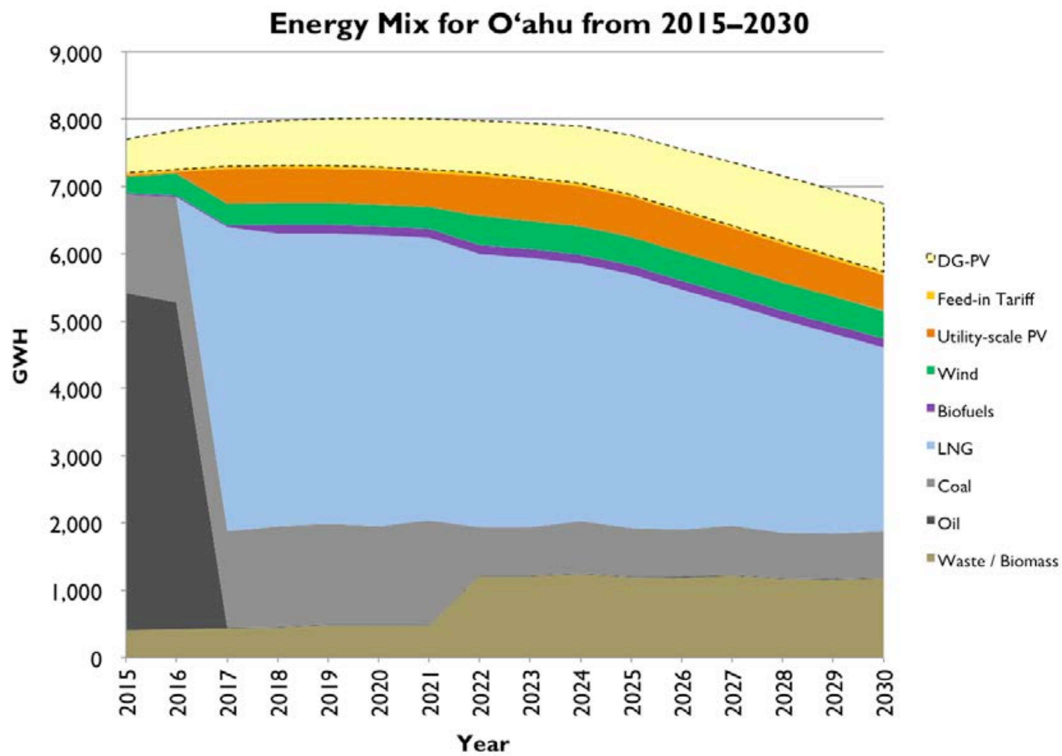

Figure 5-5. Annual Energy Mix of Hawaiian Electric Preferred Plan

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

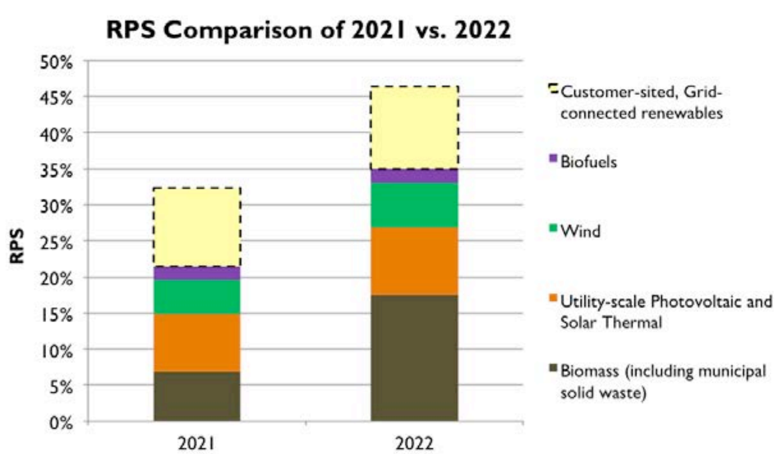

Figure 5-6. RPS Comparison of 2021vs. 2022

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.)

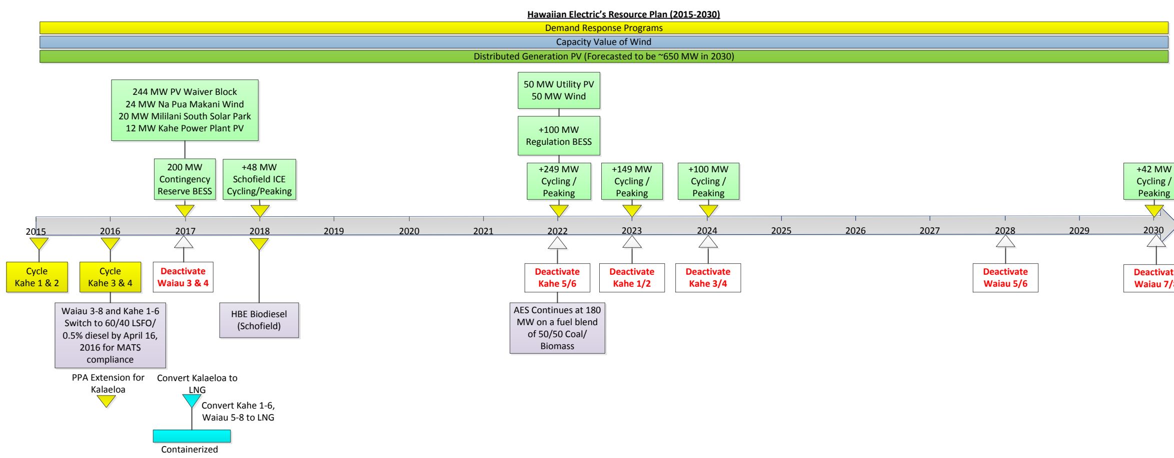

Figure 5-7. Timeline Diagram of Hawaiian Electric Preferred Plan

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.

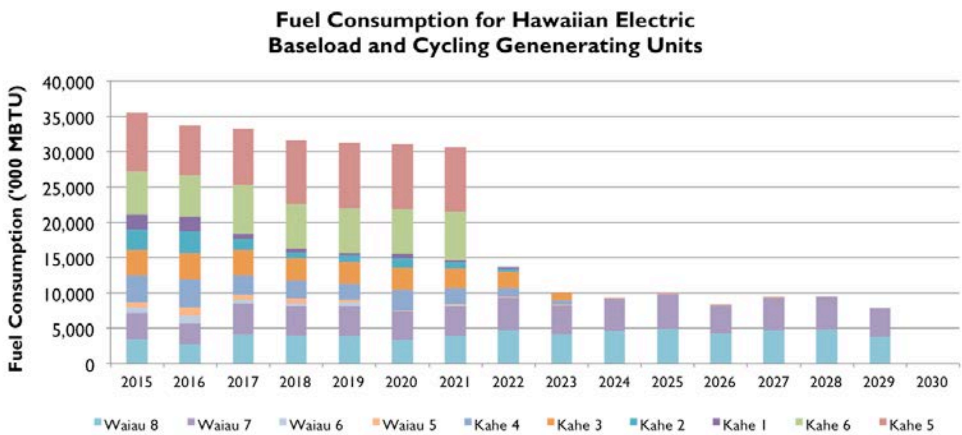

Figure 5-8. Annual Fuel Consumption for Hawaiian Electric Baseload & Cycling Generating Units

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

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[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 Oʻahu generating units.

AES Hawaiʻi (AES)

AES operates on coal and provides the lowest cost energy to the power system on Oʻahu. 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 Oʻahu grid, however, AES presents operational challenges due to its relatively large capacity (AES is the largest single "contingency" on the Oʻahu 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 Oʻahu 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 O‘ahu 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 O‘ahu 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 O‘ahu 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 O‘ahu 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 O‘ahu 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%.

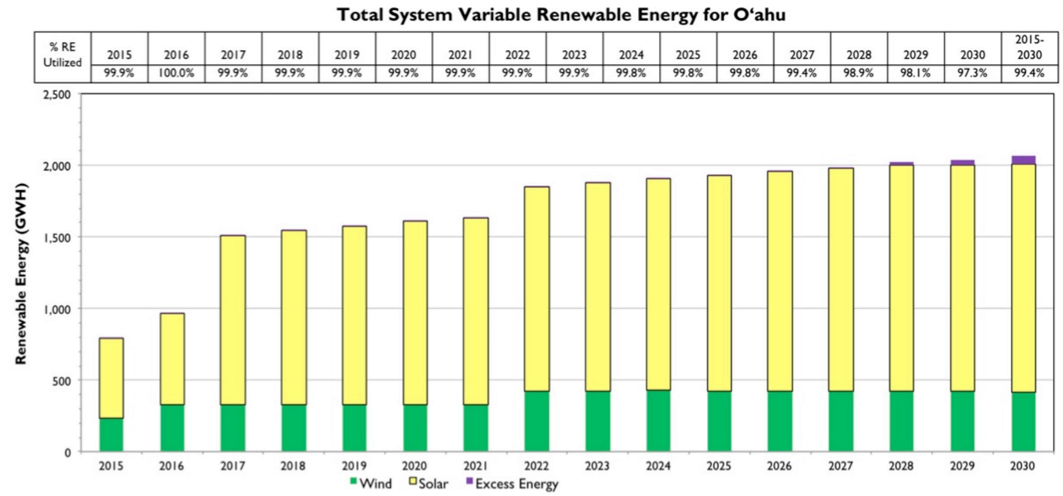

Figure 5-9. Total System Variable Renewable Energy Utilized

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).

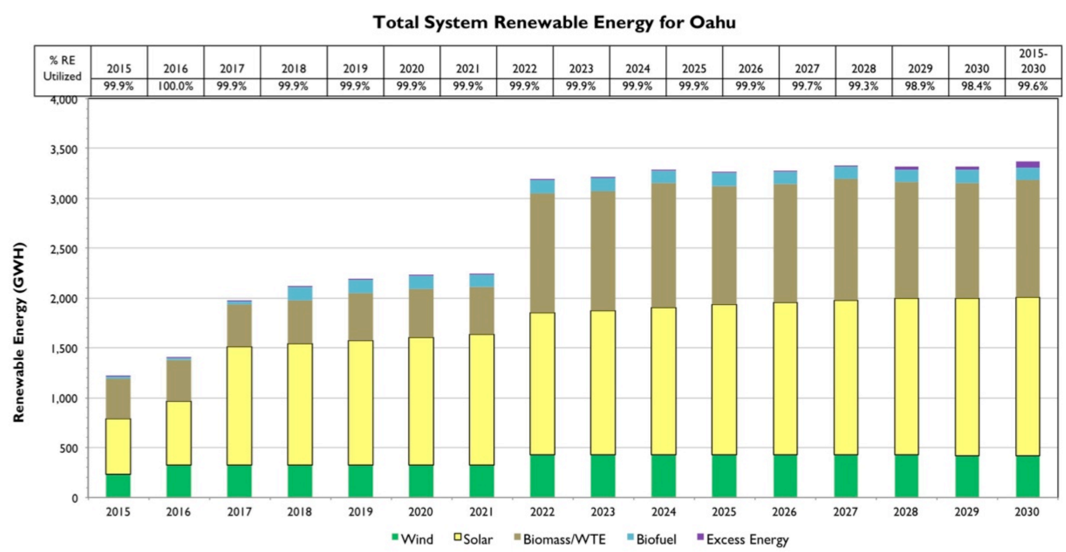

Figure 5-10. Total System Renewable Energy Utilized

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, Hawai‘i 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)

- 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)

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 Lanaʻi

On Lanaʻi, the Lanaʻi 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 Molokaʻi

Maui Electric, in collaboration with HNEI, is currently pursuing a 2 MW/375 kWh battery energy storage project on the island of Molokaʻi 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).

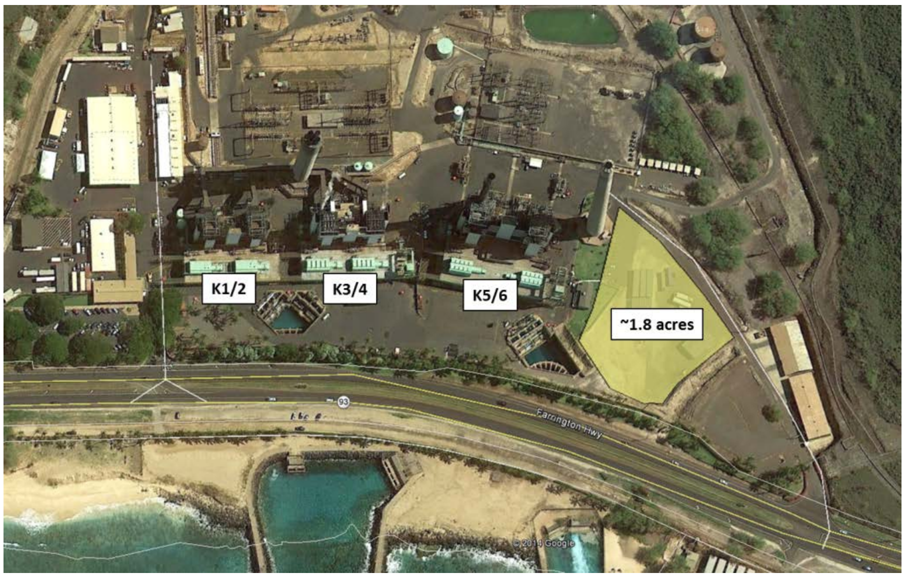

Figure 5-11. Open Space Adjacent to Kahe Units 5 and 6

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.

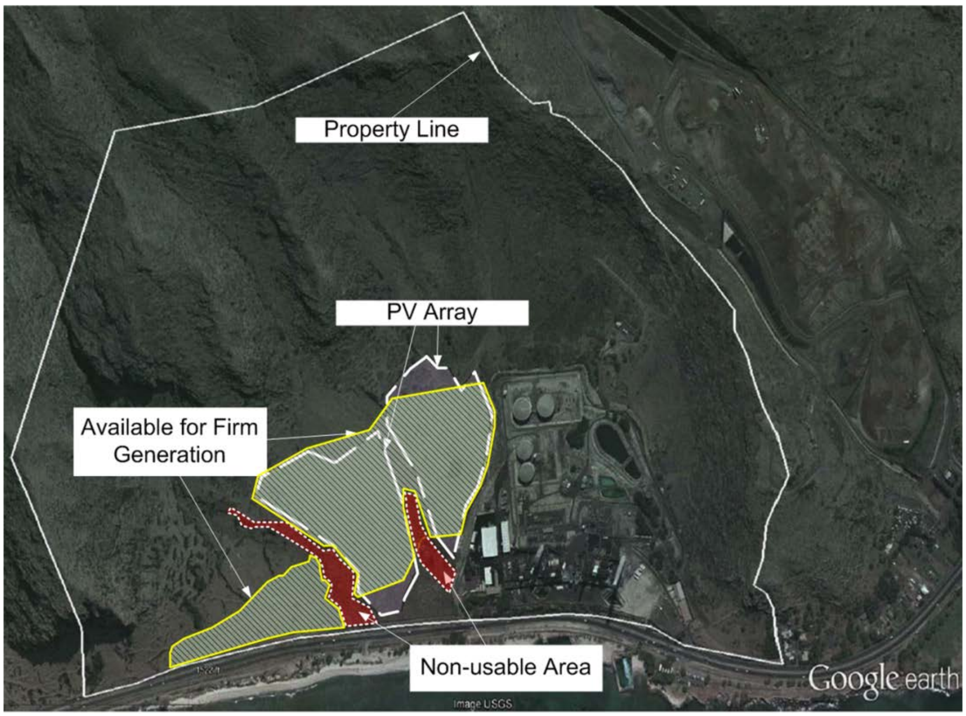

Figure 5-12. North End of Kahe Property

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.

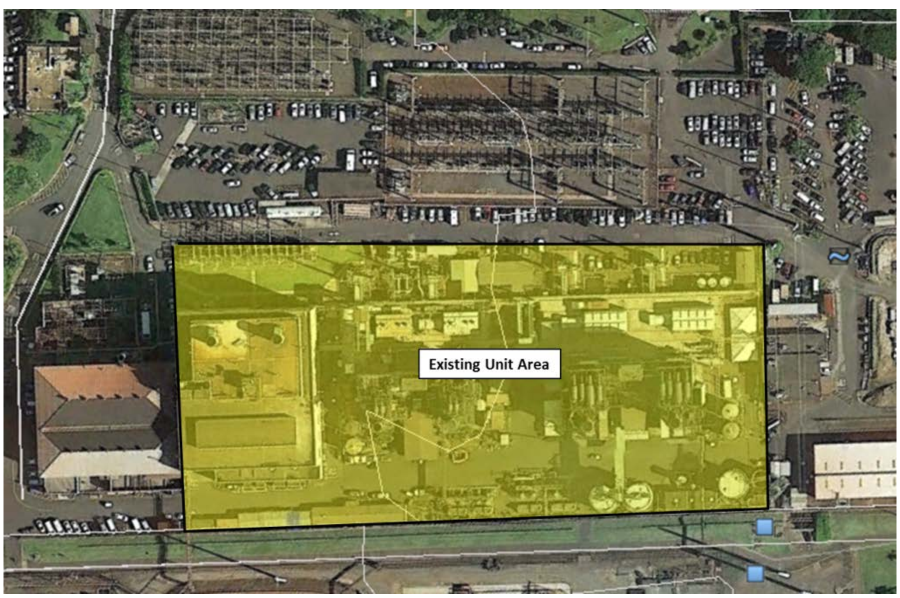

Figure 5-14. Existing Waiau Generating Unit Area

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)

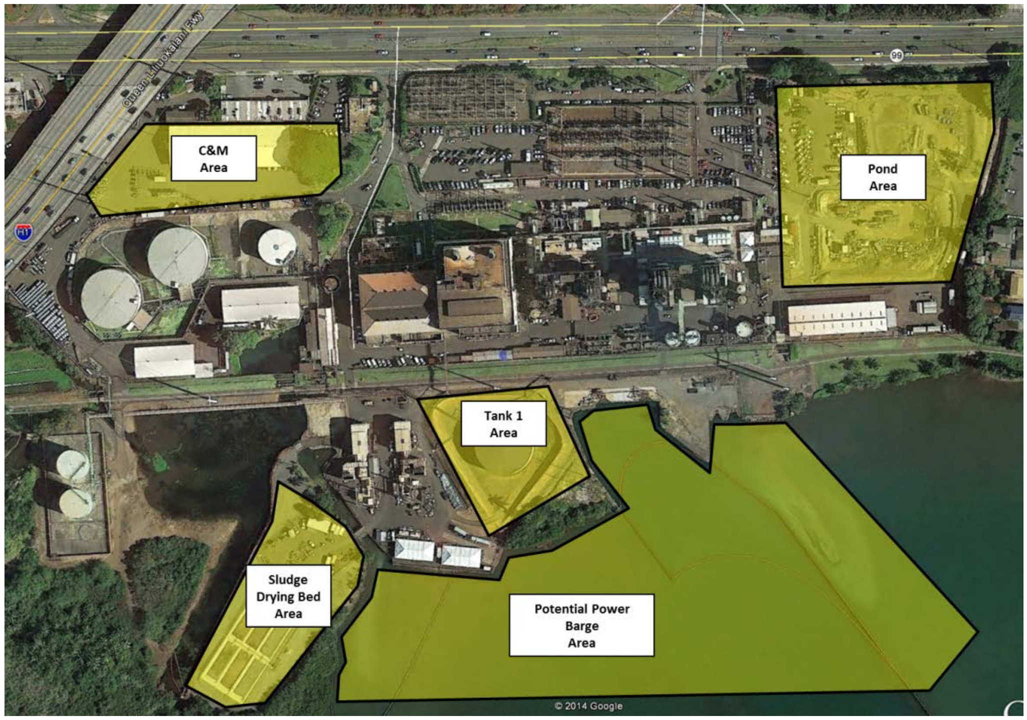

Figure 5-15. Other Areas at the Waiau Generating Station

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 O‘ahu 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,

[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

[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 Hawaiʻi, the "Director" is the Director of the Hawaiʻi 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.

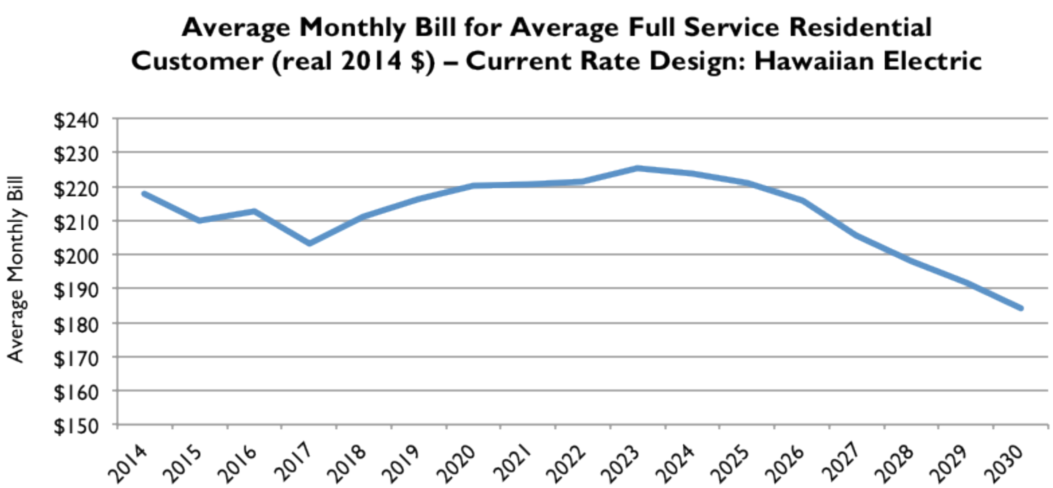

Figure 6-1. Average Full Service Residential Customer Bill Impact under Current Rate Design

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.

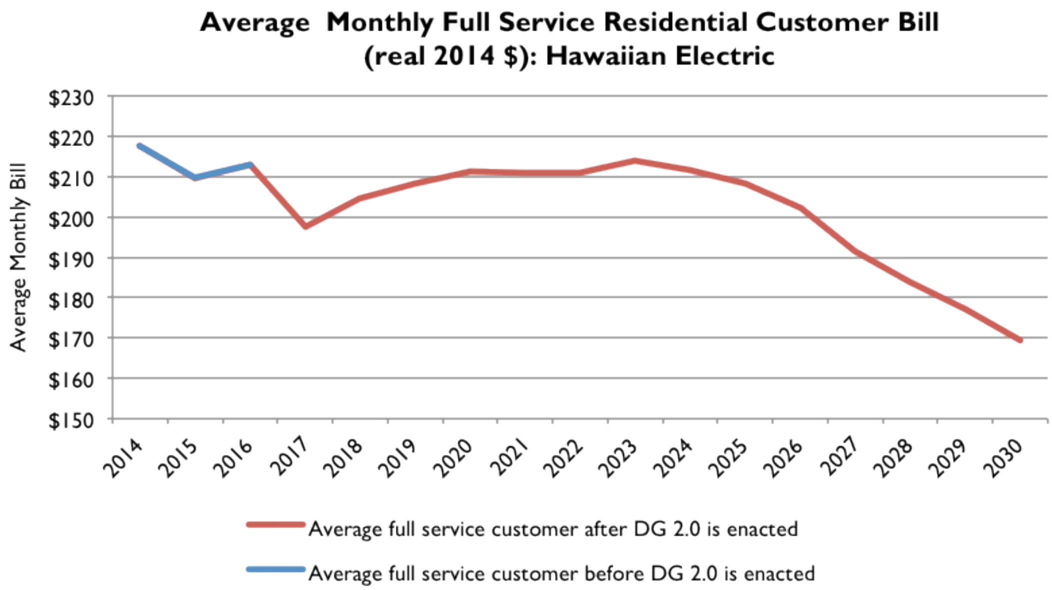

Figure 6-2. Average Full Service Residential Customer Bill Impact under DG 2.0

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.

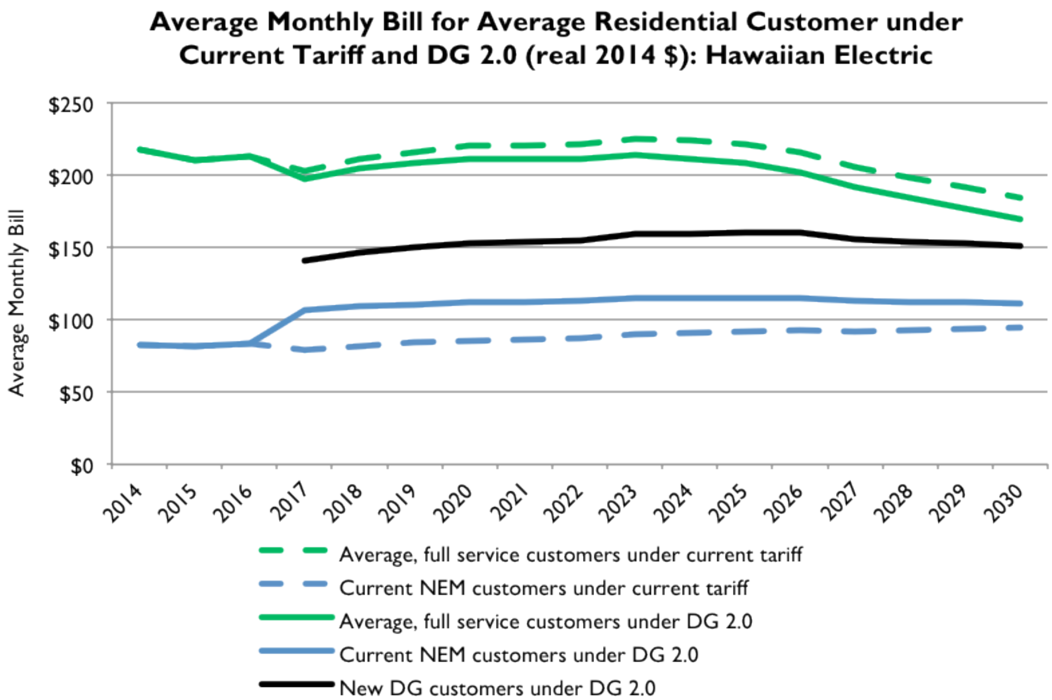

Figure 6-3. Average Residential Customer Bill Impact under Current Tariff and DG 2.0

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).

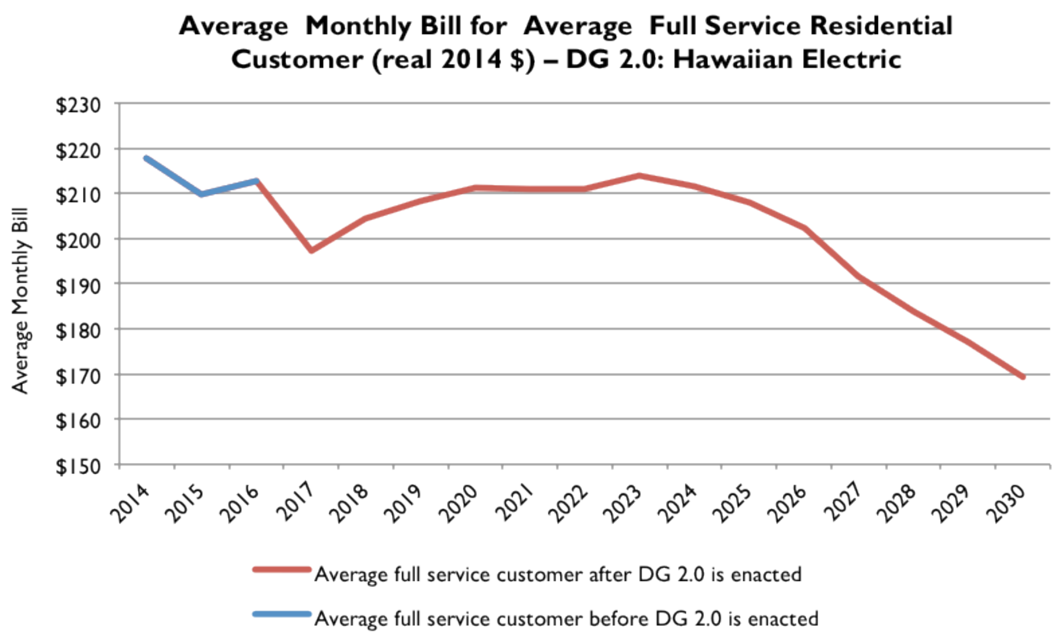

Figure 6-4. Average Monthly Bill for Average Full Service Residential Customer, Hawaiian Electric: DG 2.0

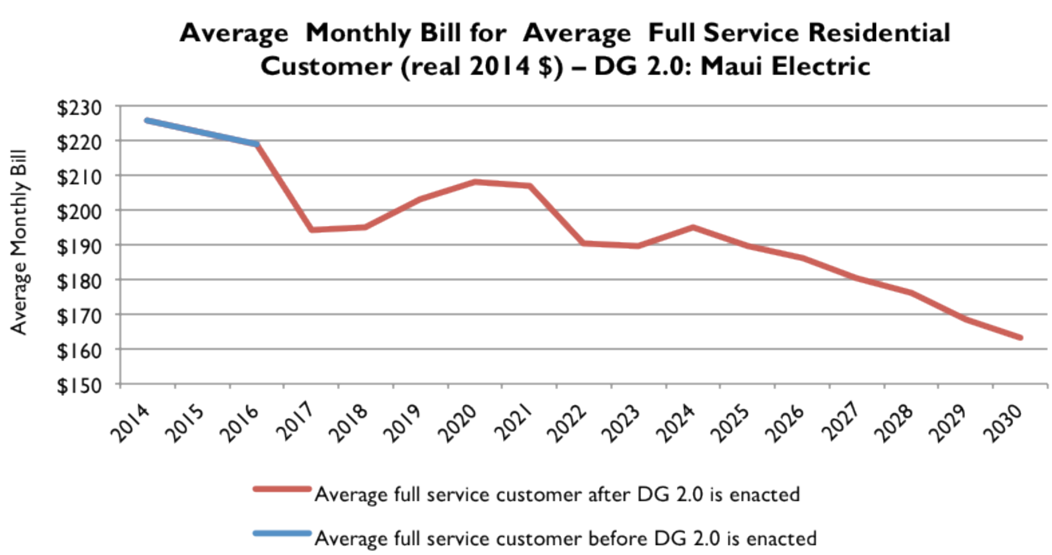

Figure 6-5. Average Monthly Bill for Average Full Service Residential Customer, Maui Electric: DG 2.0

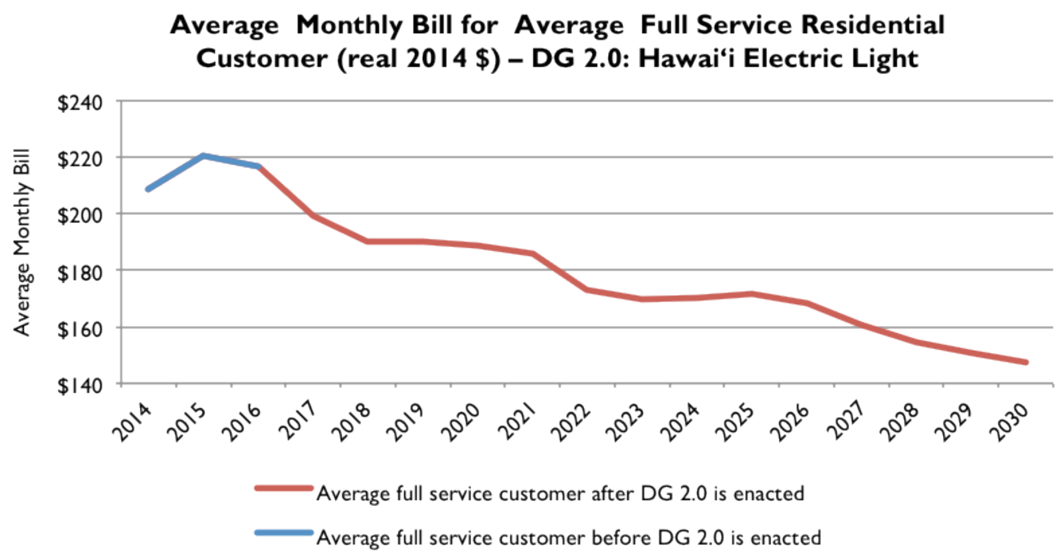

Figure 6-6. Average Monthly Bill for Average Full Service Residential Customer, Hawai'i Electric Light: DG 2.0

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.

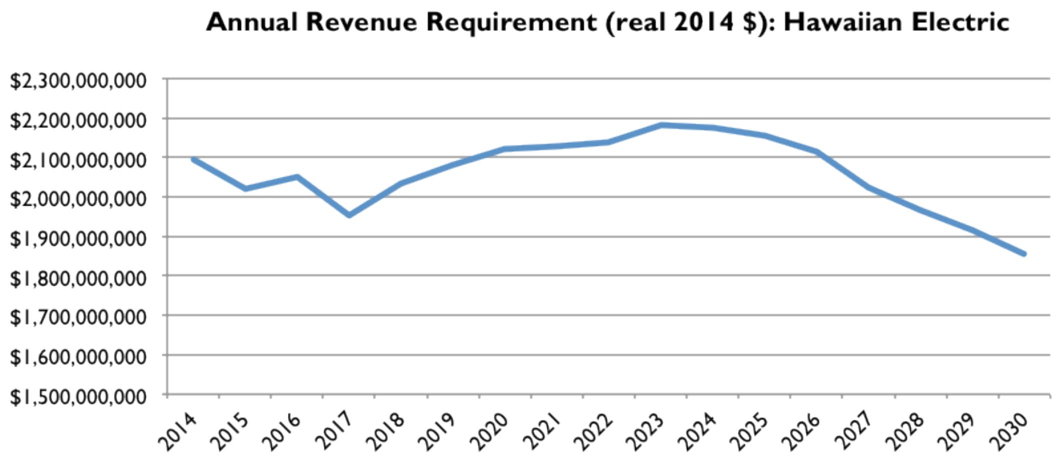

Figure 6-7. O'ahu Annual Revenue Requirement

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.

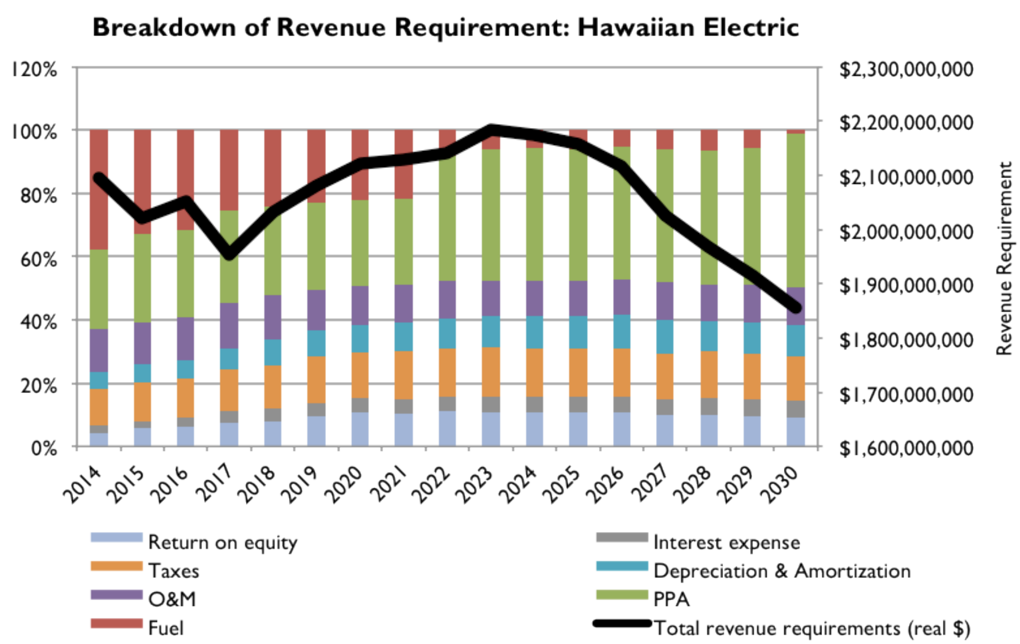

Figure 6-8. O'ahu Annual Revenue Requirement by Major Component

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.

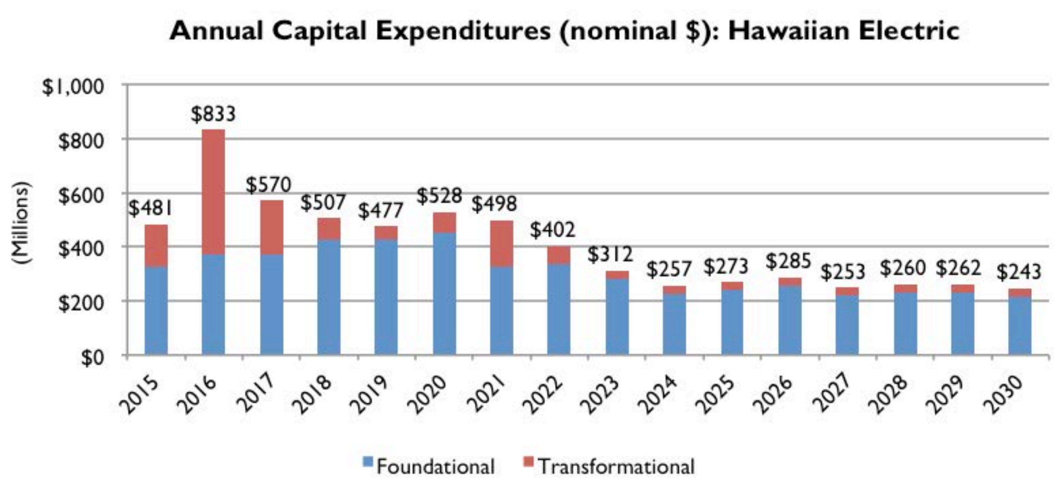

Figure 6-9. O'ahu Foundational and Transformational Capital Expenditures by Year

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.

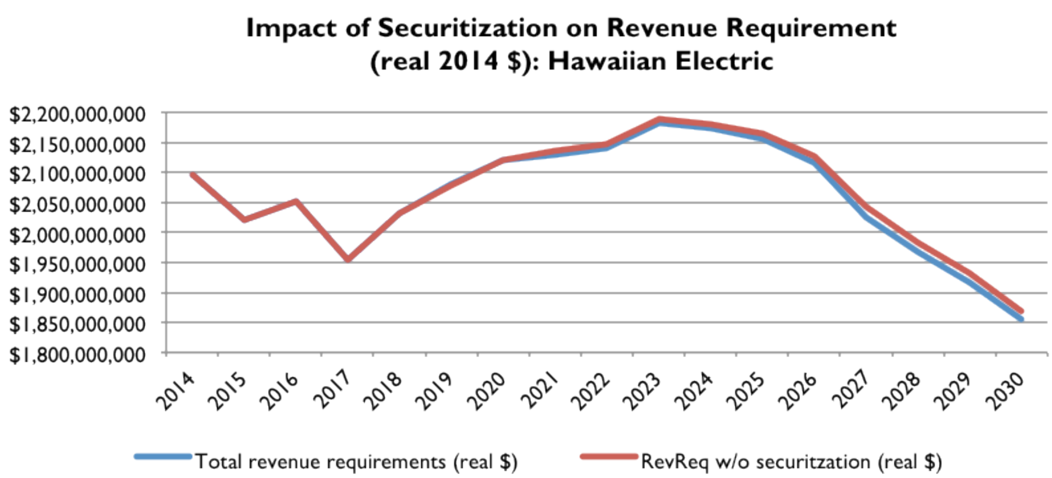

Figure 6-10. Impact of Securitization on Projected O'ahu Revenue Requirement

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 O'ahu. 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.

[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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A. Commission Order Cross Reference

In Docket No. 2011-0206, Order No. 32053 entitled "Ruling on RSWG Work Product", the Hawai'i Public Utilities Commission ordered Hawaiian Electric:

> "to file a Power Supply Improvement Plan (PSIP) with the commission within 120 days of the date of this Decision and Order, among other reasons, to provide plans as to how HECO intends to accomplish the integration of substantial amounts of variable renewable energy resources, in a reliable and economic manner, without significant curtailments of existing or future renewable resources."[56]

The Order listed a number of component plans, each with a number of issues to consider. The Order also listed other stipulations—energy storage and ancillary services—to be analyzed and evaluated.

Presented here is a cross reference between the issues raised in the Commission's Order and the locations in this PSIP where they are addressed.

[56] Docket No. 2011-0206, Order No. 32053, Section II. C. 2. iii. 11.; p91.

COMPONENT PLANS

Component Plan	PSIP Heading	Page
Fossil Generation Retirement Plan	Plan for Retiring Fossil Generation	5-21
Generation Flexibility Plan	Increasing Operational Flexibility of Existing Steam Generators Utilization of Renewable Energy	5-12 5-25
Must-Run Generation Reduction Plan	Increasing Operational Flexibility of Existing Steam Generators	5-12
Environmental Compliance Plan	Environmental Compliance	5-60
Key Generator Utilization Plan	Key Generator Utilization Plan	5-16
Optimal Renewable Energy Portfolio Plan	Hawaiian Electric: Unprecedented Levels of Renewable Energy	5-11
Generation Commitment and Economic Dispatch Review	Appendix N	N-1

Table A-1. Component Plan Cross Reference

FURTHER ACTION: ENERGY STORAGE

Further Action	PSIP Heading	Page
Energy Storage	Energy Storage Plan	5-27

Table A-2. Further Action: Energy Storage Cross Reference

ANCILLARY SERVICES

Ancillary Services	PSIP Heading	Page
Must Run Generation Reduction Plan	Increasing Operational Flexibility of Existing Steam Generators	5-12
Generation Commitment and Economic Dispatch Review	Appendix N	N-1

Table A-3. Ancillary Services Cross Reference

B. Glossary and Acronyms

This Glossary and Acronym Appendix contains the terms used throughout the Power Supply Improvement Plan (PSIP), the Distributed Generation Interconnection Plan (DGIP), and the Integrated Interconnection Queue (IIQ). The Appendix clarifies the meaning of these terms, and helps you better understand the concepts described by these terms.

A

Adequacy of Supply

The ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.

Advanced DER Technology Utilization Plan (ADERTUP)

A plan within the Distributed Generation Improvement Plan (DGIP) that sets forth the near, medium, and long-term plans by which customers would install, and utilities would utilize, advanced technologies to mitigate adverse grid impacts of distributed generation (DG) photovoltaics (PV).

Advanced Distribution Management System (ADMS)

A single system that includes an Outage Management System (OMS), Distribution Management System (DMS), and Distribution SCADA components and functionalities all in one platform, with a single user interface for the operator. ADMS will be used to help manage and integrate the new technologies and applications to be deployed as part of the utility's grid modernization program.

Advanced Inverter

A smart inverter capable of being interconnected to the utility (via two-way communications) and controlled by it.

Advanced Metering Infrastructure (AMI)

A primary component of a modern grid that provides two-way communications between the customer premises and the utility. An AMI is a necessary prerequisite to the interactions with advanced inverters, customer sited storage, demand response through direct load control, and EVs.

Alternating Current (AC)

An electric current whose flow of electric charge periodically reverses direction. In Hawaiʻi, the mainland United States, and in many other developed countries, AC is the form in which electric power is delivered to businesses and residences. The usual waveform of an AC power circuit is a sine wave. In Hawaiʻi and the mainland United States, the usual power system frequency of 60 hertz (1 hertz (Hz) = 1 cycle per second).

Ancillary Services

Services that supplement capacity as needed in order to meet demand or correct deviations in frequency. These include reserves, black start resources, and frequency response.

As-Available Renewable Energy

See Variable Renewable Energy on page B-35.

Avoided Costs

The costs that utility customers would avoid by having the utility purchase capacity and/or energy from another source (for example, energy storage or demand response) or from a third party, compared to having the utility generate the electricity itself. Avoided costs comprise two components:

- Avoided capacity costs, which includes avoided capital costs (for example, return on investment, depreciation, and income taxes) and avoided fixed operation and maintenance costs.
- Avoided energy costs, which includes avoided fuel costs and avoided variable operation and maintenance costs.

B

Baseload

The minimum electric or thermal load that is supplied continuously over a period of time. See also Load, Electric on page B-19.

Baseload Capacity

See Capacity, Generating on page B-4.

Baseload Generation

The production of energy at a constant rate, to support the system's baseload.

Battery Energy Storage Systems (BESS)

Any battery storage system used for contingency or regulating reserves, load shifting, ancillary services, or other utility or customer functions. See also Storage on page B-31.

Black Start

The ability of a generating unit or station to go from a shutdown condition to an operating condition and start delivering power without assistance from the electric system.

British Thermal Unit (Btu)

A unit of energy equal to about 1055 joules that describes the energy content of fuels. A Btu is the amount of heat required to raise the temperature of 1 pound of water by 1°F at a constant atmospheric pressure. When measuring electricity, the proper unit would be Btu per hour (or Btu/h) although this is generally abbreviated to just Btu. The term MBtu means a thousand Btu; the term MMBtu means a million Btu.

Buy-All/Sell-All

Tariff structure for DER under which customers would sell their entire DG output to the utility and purchase all of their requirements from the utility. This structure requires a two-meter system, with one meter to monitor grid import/export and one to monitor generation from the PV system.

C

Capacitor

A device that helps improve the efficiency of the flow of electricity through distribution lines by reducing energy losses. This is accomplished by the capacitor's ability to correct AC voltage so that the voltage is in phase with the AC current. Capacitors are typically installed in substations and on distribution system poles.

Capacity Factor (cf)

The ratio of the average operating load of an electric power generating unit for a period of time to the capacity rating of the unit during that period of time.

Capacity, Generating

The rated continuous load-carrying ability, expressed in megawatts (MW) or megavolt-amperes (MVA) of an electric generating plant. It is the maximum power that a machine or system can produce or carry under specified conditions, usually expressed in kilowatts or megawatts. Capacity is an attribute of an electric generating plant that does not depend on how much it is used. Types of capacity include:

Baseload Capacity: Those generating facilities within a utility system that are operated to the greatest extent possible to maximize system mechanical and thermal efficiency and minimize system operating costs. Baseload capacity typically operates at high annual capacity factors, for example greater than 60%.

Firm Capacity: Capacity that is intended to be available at all times during the period covered by a commitment, even under adverse conditions.

Installed Capacity (ICAP): The total capacity of all generators able to serve load in a given power system. Also called ICAP, the total wattage of all generation resources to serve a given service or control area.

Intermediate Capacity: Flexible generators able to efficiently vary their output across a wide band of loading conditions. Also known as Cycling Capacity. Typically annual capacity factors for intermediate duty generating units range from 20% to 60%.

Net Capacity: The maximum capacity (or effective rating), modified for ambient limitations, that a generating unit, power plant, or electric system can sustain over a specified period, less the capacity used to supply the demand of station service or auxiliary needs.

Peaking Capacity: Generators typically called on for short periods of time during system peak load conditions. Annual capacity factors for peaking generation are typically less than 20%.

Capital Expenditures

Funds expended by a utility to construct, acquire or upgrade physical assets (generating plants, energy storage devices, transmission plant, distribution plant, general plant, major software systems, or IT infrastructure). Capital expenditures for a given asset include funds expended for the acquisition and development of land related to the asset, obtaining permits and approvals related to the asset, environmental and engineering studies specifically related to construction of the asset, engineering design of the asset, procurement of materials for the asset, construction of the asset, and startup activities related to the asset. Capital expenditures may be associated with a new asset or an existing asset (that is, renovations, additions, upgrades, and replacement of major components).

Carbon Dioxide (CO_2)

A greenhouse gas produced when carbon-based fossil fuels are combusted.

Combined Cycle (CC)

A combination of combustion turbine- and steam turbine-driven electrical generators, where the combustion turbine exhaust is passed through a heat recovery waste heat boiler which, in turn, produces steam which drives the steam turbine.

2x1 Combined Cycle: A configuration in which there are two combustion turbines, one heat recovery waste heat boiler, and one steam turbine. The combustion turbines produce heat for the single waste heat boiler, which in turn produces steam that is directed to the single steam turbine.

Dual-Train Combined Cycle (DTCC): A configuration in which there are two combustion turbines, two heat recovery waste heat boilers and one steam turbine. Each combustion turbine/waste heat boiler combination produces steam that is directed to the single steam turbine.

Single-Train Combined Cycle (STCC): A configuration in which there is one combustion turbine, one heat recovery waste heat boiler, and one steam turbine.

Combined Heat and Power (CHP)

The simultaneous production of electric energy and useful thermal energy for industrial or commercial heating or cooling purposes. The Energy Information Administration (EIA) has adopted this term in place of cogeneration.

Combustion Turbine (CT)

Any of several types of high-speed generators using principles and designs of jet engines to produce low cost, high efficiency power. Combustion turbines typically use natural gas or liquid petroleum fuels to operate.

Commercial and Industrial Direct Load Control (CIDLC)

A demand response program that provides financial incentives to qualified businesses for participating in demand control events. Such a program is designed for large commercial and industrial customers.

Commercial and Industrial Dynamic Pricing (CIDP)

A demand response program that provides tariff-based dynamic pricing options for electrical power to commercial and industrial customers. CIDP encourages customers to reduce demand when the overall load is high.

Conductor Sag

The distance between the connection point of a conductor (transmission/distribution line) and the lowest point of the line.

Connected Load

See Load, Electric on page B-19.

Contingency Reserve

The reserve deployed to meet contingency disturbance requirements, the largest single resource contingency on each island.

Curtailment

Cutting back on variable resources during off-peak periods of low electricity use in order to keep generation and consumption of electricity in balance.

D

Daytime Minimum Load (DML)

The absolute minimum demand for electricity between 9 AM and 5 PM on one or more circuits each day.

Demand

The rate at which electricity is used at any one given time (or averaged over any designated interval of time). Demand differs from energy use, which reflects the total amount of electricity consumed over a period of time. Demand is often measured in Kilowatts (kW = 1 Kilowatt = 1000 watts), while energy use is usually measured in Kilowatt-hours (kWh = Kilowatts x hours of use = Kilowatt-hours). Load is considered synonymous with demand. (See also Load, Electric on page B-19.)

Demand Charge

A customer charge intended to allocate fixed grid costs to customers based on each customer's consumption demand.

Demand Response (DR)

Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized. The underlying objective of demand response is to actively engage customers in modifying the demand for electricity, in lieu of a generating plant supplying the demand.

> ***Load Control:*** Includes direct control by the utility or other authorized third party of customer end-uses such as air conditioners, lighting, and motors. Load control may entail partial or load reductions or complete load interruptions. Customers usually receive financial consideration for participation in load control programs.
>
> ***Price Response:*** Refers to programs that provide pricing incentives to encourage customers to change their electricity usage profile. Price response programs include real-time pricing, dynamic pricing, coincident peak pricing, time-of-use rates, and demand bidding or buyback programs.

Demand-Side Management (DSM)

The planning, implementation, and monitoring of utility activities designed to encourage consumers to modify patterns of electricity usage, including the timing and level of electricity demand. It refers only to energy and load-shape modifying activities that are undertaken in response to utility or third party-administered programs. It does not refer to energy and load-shape changes arising from the normal operation of the marketplace or from government-mandated energy efficiency standards. Demand--Side Management (DSM) covers the complete range of load-shape objectives, including strategic conservation and load management, as well as strategic load growth.

Department of Business, Economic Development, & Tourism (DBEDT)

Hawaiʻi's resource center for economic and statistical data, business development opportunities, energy and conservation information, and foreign trade advantages. DBEDT's mission is to achieve a Hawaiʻi economy that embraces innovation and is globally competitive, dynamic and productive, providing opportunities for all Hawaiʻi's citizens. Through our attached agencies, we also foster planned community development, create affordable workforce housing units in high-quality living environments, and promote innovation sector job growth.

Department of Land and Natural Resources (DLNR)

A department within the Hawaiʻi state government responsible for managing state parks and other natural resources.

Direct Current (DC)

A department within the Hawaiʻi state government responsible for managing Hawaiʻi's unique natural and cultural resources. Also oversees state-owned and state conservation lands.

Distributed Energy Resources Technical Working Group (DER-TWG)

A working group to be formed as a review committee for DER-related technical assessments.

DG 2.0

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.

Direct Current (DC)

An electric current whose flow of electric charge remains constant. Certain renewable power generators (such as solar PV) deliver DC electricity, which must be converted to AC electricity, using an inverter, for use in the power system.

Direct Load Control (DLC)

This Demand-Side Management category represents the consumer load that can be interrupted by direct control of the utility system operator. For example, the utility may install a device such as a radio-controlled device on a customer's air-conditioning equipment or water heater. During periods of system need, the utility will send a radio signal to the appliance with this device and control the appliance for a set period of time.

Direct Transfer Trip

A protection mechanism that originates from station relays in response to a substation event.

Dispatchable Generation

A generation source that is controlled by a system operator or dispatcher who can increase or decrease the amount of power from that source as the system requirements change.

Distributed Circuit Improvement Implementation Plan (DCIIP)

A plan within the Distributed Generation Interconnection Plan (DGIP) that summarizes the specific strategies and action plans, including associated costs and schedules, to implement circuit upgrades and other mitigation measures to increase capacity of electrical grids to interconnect additional distributed generation.

Distributed Energy Resources (DER)

Non-centralized generating and storage systems that are co-located with energy load.

Distributed Energy Storage

Energy storage systems sited on the distribution circuit, including substation-sited and customer-sited storage.

Distributed Generation (DG)

A term referring to a small generator, typically 10 megawatts or smaller, that is sited at or near load, and that is attached to the distribution grid. Distributed generation can serve as a primary or backup energy source and can use various technologies, including combustion turbines, reciprocating engines, fuel cells, wind generators, and photovoltaics. Also known as a Distributed Energy Resource (see page B-9).

Distributed Generation Interconnection Capacity Analysis (DGICA)

A plan within DGIP to proactively identify distribution circuit capacity constraints to the safe and reliable interconnection of distributed generation resources. Includes system upgrade requirements necessary to increase circuit interconnection capability in major capacity increments.

Distribution Automation (DA)

Programs to allow monitoring and control of all distribution level sources, as well as the automation of feeders to provide downstream monitoring and control.

Distribution Circuit Monitoring Program (DCMP)

A document filed by the Companies on June 27, 2014, outlining three broad goals. First, to measure circuit parameters to determine the extent to which distributed solar photovoltaic (PV) generation is causing safety, reliability, or power quality issues. Second, to ensure that distributed generation circuit voltages are within tariff and applicable standards. Third, to increase the Companies' knowledge of what is occurring on high PV penetration circuits to determine boundaries and thresholds and further future renewable DG integration work.

Distribution Circuit

The physical elements of the grid involved in carrying electricity from the transmission system to end users.

Distribution Transformer

A transformer used to step down voltage from the distribution circuit to levels appropriate for customer use.

Disturbance Ride-Through

The capability of DG systems to remain connected to the grid under non-standard voltage levels.

Droop

The amount of speed (or frequency) change that is necessary to cause the main prime mover control mechanism to move from fully closed to fully open. In general, the percent movement of the main prime mover control mechanism can be calculated as the speed change (in percent) divided by the per unit droop.

Dual-Train Combined Cycle (DTCC)

See Combined Cycle on page B-5.

E

Economic Dispatch

The start-up, shutdown, and allocation of load to individual generating units to effect the most economical production of electricity for customers.

Electric Power Research Institute (EPRI)

A nonprofit research and development organization that conducts research, development and demonstration relating to the generation, delivery, and use of electricity.

Electric Vehicle (EV)

A vehicle that uses one or more electric motors or traction motors for propulsion.

Electricity

The set of physical phenomena associated with the presence and flow of electric charge.

Energy

The ability to produce work, heat, light, or other forms of energy. It is measured in watt-hours. Energy can be computed as capacity or demand (measured in watts), multiplied by time (measured in hours). For example, a 1 megawatt (one million watts) power plant running at full output for 1 hour will produce 1 megawatt-hour (one million watt-hours or 1000 kilowatt-hours) of electrical energy.

Emissions

An electric power plant that combusts fuels releases pollutants to the atmosphere (for example, emissions of sulfur dioxide) during normal operation. These pollutants may be classified as primary (emitted directly from the plant) or secondary (formed in the atmosphere from primary pollutants). The pollutants emitted will vary based on the type of fuel used.

Energy Efficiency DSM

Programs designed to encourage the reduction of energy used by end-use devices and systems. Savings are generally achieved by substituting more technologically advanced equipment to produce the same level of energy services (for example, lighting, water heating, motor drive) with less electricity. Examples include programs that promote the adoption of high-efficiency appliances and lighting retrofit programs through the offering of incentives or direct install services.

Energy Efficiency Portfolio Standard (EEPS)

A goal for reducing the demand for electricity in Hawai'i through the use of energy efficiency and displacement or offset technologies set by state law. The EEPS goes into effect in January 2015. Until then, energy savings from these technologies are included in the calculations for Hawai'i's RPS. The EEPS for Hawai'i provides for a total energy efficiency target of 4,300,000 megawatt-hours per year by the year 2030. To the extent that this target is achieved, this quantity of electric energy will not be served by Hawai'i's electric utilities. Therefore, the projected amount of energy reductions due to energy efficiency are removed from the system energy requirement forecasts used in this PSIP.

Energy Excelerator

A program of the Pacific International Center for High Technology Research that funds seed-stage and growth-stage startups with compelling energy solutions and immediate applications in Hawaiʻi, helping them succeed by providing funding, strategic relationships, and a vibrant ecosystem.

Energy Management System (EMS)

A computer system,including data-gathering tools used to monitor and control electrical generation and transmission.

Expense

An outflow of cash or other consideration (for example, incurring a commercial credit obligation) from a utility to another person or company in return for products or services (fuel expense, operating expense, maintenance expense, sales expense, customer service expense, interest expense.). An expense might also be a non-cash accounting entry where an asset (created as a result of a Capital Expenditure) is used up (for example, depreciation expense) or a liability is incurred.

Export Model

A model for DG PV interconnection in which co-incident self-generation and usage is not metered, excess energy is exported to the grid, and energy is imported to meet additional customer needs.

F

Feeder

A circuit carrying power from a major conductor to a one or more distribution circuits.

Firm Capacity

See Capacity, Generating on page B-4.

Feed-In-Tariff (FIT) Program

A FIT program specific to Hawaiian Electric, under guidelines issued by the Hawaiʻi Public Utilities Commission, which provides for customers to sell all the electric energy produced to the electric company.

Feed-In-Tariff (FIT)

The generic term for the rate at which exported DG PV is compensated by the utility.

First-In-First-Out (FiFo)

The policy for clearing the DG interconnection queues, under which applications are processed in the order in which they were received.

Flicker

An impression of unsteadiness of visual sensation induced by a light stimulus whose luminance or spectral distribution fluctuates with time.

Flywheel

See Storage one page B-31.

Forced Outage

See Outage on page B-23.

Forced Outage Rate

See Outage on page B-23.

Fossil Fuel

Any naturally occurring fuel formed from the decomposition of buried organic matter, essentially coal, petroleum (oil), and natural gas. Fossil fuels take millions of years to form, and thus are non-renewable resources. Because of their high percentages of carbon, burning fossil fuels produces about twice as much carbon dioxide (a greenhouse gas) as can be absorbed by natural processes.

Frequency

The number of cycles per second through which an alternating current passes. Frequency has been generally standardized in the United States electric utility industry at 60 cycles per second (60 Hz). The power system operator strives to maintain the system frequency as close as possible to 60 Hz at all times by varying the output of dispatchable generators, typically through automatic means. In general, if demand exceeds supply, the frequency will drop below 60 Hz; if supply exceeds demand, the frequency will rise above 60 Hz. If the system frequency drops to an unacceptable level (under-frequency), or rises to an unacceptable level (over-frequency), a system failure can occur. Accordingly, system frequency is an important indicator of the power system's condition at any given point in time.

Frequency Regulation

The effort to keep an alternating current at a consistent 60 Hz per second (or other fixed standard).

Full-Forced Outage

See Outage on page B-23.

Full Service Customer

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.

G

Generating Capacity

See Capacity, Generating on page B-4.

Generation (Electricity)

The process of producing electrical energy from other forms of energy; also, the amount of electric energy produced, usually expressed in kilowatt-hours (kWh) or megawatt hours (MWh).

> ***Nameplate Generation (Gross Generation):*** The electrical output at the terminals of the generator, usually expressed in megawatts (MW).
>
> ***Net Generation:*** Gross generation minus station service or unit service power requirements, usually expressed in megawatts (MW). The energy required for pumping at a pumped storage plant is regarded as plant use and must be deducted from the gross generation.

Generator (Electric)

A machine that transforms mechanical, chemical, or thermal energy into electric energy. Includes wind generators, solar PV generators, and other systems that convert energy of one form into electric energy. See also Capacity, Generating on page B-4.

Geographic Information System (GIS)

A computer system designed to capture, store, manipulate, analyze, manage, and present all types of geographical data.

Gigawatt (GW)

A unit of power, capacity, or demand equal to one billion watts.

Gigawatt-hour (GWh)

A unit of electric energy equal to one billion watt-hours.

Grandfather

To exempt a class of customers from changes to the laws or regulations under which they operate.

Greenhouse Gases (GHG)

Any gas whose absorption of solar radiation is responsible for the greenhouse effect, including carbon dioxide, methane, ozone, and the fluorocarbons.

Grid (Electric)

An interconnected network of electric transmission lines and related facilities.

Grid Modernization

The full suite of technologies and capabilities—including the data acquisition capabilities, controlling devices, telecommunications, and control systems—necessary to operate the utility's modernized electric grid. This includes Advanced Metering Infrastructure (AMI) with two-way communications and all the components to implement an Advanced Distribution Management System/Energy Management System. Additional components might include Volt-VAR Optimization (VVO); demand response; control of DG (curtailment and other); adaptive relaying (dynamic load shed); transformer monitoring; and potentially other advanced analytics, reporting, and monitoring capabilities.

Gross Generation

See Generation (Electricity) on page B-14.

Ground Fault Overvoltage

A transient overvoltage issue that occurs when the neutral of a wye grounded system shifts, causing a temporary overvoltage on the unfaulted phase.

Grounding Transformer

A transformer that provides a safe path to ground.

H

Hawai'i Public Utilities Commission (PUC)

A state agency that regulates all franchised or certificated public service companies operating in Hawai'i. The PUC prescribes rates, tariffs, charges and fees; determines the allowable rate of earnings in establishing rates; issues guidelines concerning the general management of franchised or certificated utility businesses; and acts on requests for the acquisition, sale, disposition or other exchange of utility properties, including mergers and consolidations.

Hawai'i Revised Statute (HRS)

The codified laws of the State of Hawai'i. The entire body of state laws is referred to the Hawai'i Revised Statutes; the abbreviation HRS is normally used when citing a particular law.

Heat Rate

A measure of generating station thermal efficiency, generally expressed in Btu per net kilowatt-hour. It is computed by dividing the total Btu content of fuel burned for electric generation by the resulting net kilowatt-hour generation.

High Voltage Direct Current (HVDC)

An electric power transmission system that uses direct current, rather than alternating current, for bulk transmission.

I

Impacts

The positive or negative consequences of an activity. For example, there may be negative consequences associated with the operation of power plants from the emission discharge or release of a material to the environment (for example, health effects). There may also be positive consequences resulting from the construction and siting of power plants which could affect society and culture.

Impedance

A measure of the opposition to the flow of power in an AC circuit.

Independent Power Producer (IPP)

Any entity that owns or operates an electricity generating facility that is not included in an electric utility's rate base. This term includes, but is not limited to, co-generators (or combined heat and power generators) and small power producers (including net metered and feed-in-tariff systems) and all other non-utility electricity producers, such as exempt wholesale generators, who sell electricity or exchange electricity with the utility. IPPs are also sometimes referred to as non-utility generators (NUGs).

Installed Capacity

See Capacity, Generating on page B-4.

Integrated Demand Response Portfolio Plan (IDRPP)

A Comprehensive Demand Response program proposal filed by the Companies with the Hawai'i Public Utilities Commission on July 28, 2014.

Integrated Interconnection Queue (IIQ)

Recommendations and plan for implementing and organizing an Integrated Interconnection Queue across all DG programs as directed by the Hawai'i Public Utilities Commission in Order 32053, to be filed on August 26, 2014.

Integrated Resource Plan (IRP)

The plan by which electric utilities identify the resources or the mix of resources for meeting near- and long-term consumer energy needs. An IRP conveys the results from a planning, analysis, and decision-making process that examines and determines how a utility will meet future demands. Developed in the 1980s, the IRP process integrates efficiency and load management programs, considered on par with supply resources; broadly framed societal concerns, considered in addition to direct dollar costs to the utility and its customers; and public participation into the utility planning process.

Interconnection Charge

A one-off charge to DG customers reflecting costs of studies and any potential upgrades (such as transformer upgrades) associated with distributed generation.

Interconnection Requirements Study (IRS)

Studies conducted by the Hawaiian Electric Companies on specific DG interconnection requests that may require mitigation measures to ensure circuit stability.

Intermediate Capacity

See Capacity, Generating on page B-4.

Intermittent Renewable Energy

See Variable Renewable Energy on page B-35.

Inverter

A device that converts direct current (DC) electricity to alternating current (AC) either for stand-alone systems or to supply power to an electricity grid. An appropriately designed inverter can provide dynamic reactive power as well as real power and low voltage ride-through capability. A solar PV system uses inverters to convert DC electricity to AC electricity for use in the grid, or directly by a customer.

Islanding

A condition in which a circuit remains powered by non-utility generation (that is, distributed generation resources) even when the circuit has been disconnected from the wider utility power network.

K

Kilowatt (KW)
A unit of power, capacity, or demand equal to one thousand watts. The Companies sometimes express the demand for an individual electric customer, or the capacity of a distributed generator in kilowatts. The standard billing unit for electric tariffs with a demand charge component is the kilowatt.

Kilowatt-hour (KWh)
A unit of electric energy equal to one thousand watt-hours. The standard billing unit for electric energy sold to retail consumers is the kilowatt-hour.

L

Laterals
Lines branching off the primary feeder on a distribution circuit.

Levelized Cost of Energy (LCOE)
The price per kilowatt-hour in order for an energy project to break even; it does not include risk or return on investment.

Life-Cycle Costs
The total cost impact over the life of a program or the life of an asset. Life-cycle costs include Capital Expenditures, operation, maintenance and administrative expenses, and the costs of decommissioning.

Liquefied Natural Gas (LNG)
Natural gas that has been cooled until it turns liquid, in order to make storage and transport easier.

Live-Line Block Closing
Restrictions on the re-closing of feeders with interconnected DG PV systems based on line voltage levels.

Load, Electric

The term load is considered synonymous with demand. Load may also be defined as an end-use device or an end-use customer that consumes power. Using this definition of load, demand is the measure of power that a load receives or requires.

Baseload: The minimum load over a given period of time.

Connected Load: The sum of the capacities or ratings of the electric power consuming apparatus connected to a supplying system, or any part of the system under consideration.

Load Balancing

The efforts of the system operator to ensure that the load is equal to the generation. During normal operating conditions the system operator utilizes load following and frequency regulation for load balancing.

Load Control Program

A program in which the utility company offers some form of compensation (for example, a bill credit) in return for having permission to control a customer's air conditioner or water heater for short periods of time by remote control.

Load Forecast

An estimate of the level of future energy needs of customers in an electric system. Bottom-up forecasting uses utility revenue meters to develop system-wide loads; used often in projecting loads of specific customer classes. Top-down forecasting uses utility meters at generation and transmission sites to develop aggregate control area loads; useful in determining reliability planning requirements, especially where retail choice programs are not in effect.

Load Management DSM

Electric utility or third party marketing programs designed to encourage the utility's customers to adjust the timing of their energy consumption. By coordinating the timing of its customers' consumption, the utility can achieve a variety of goals, including reducing the utility's peak system load, increasing the utility's minimum system load, and meeting unusual, transient, or critical system operating conditions.

Load Profile

Measurements of a customer's electricity usage over a period of time which shows how much and when a customer uses electricity. Load profiles can be used by suppliers and transmission system operators to forecast electricity supply requirements and to determine the cost of serving a customer.

Load Shedding

A purposeful, immediate response to curtail electric service. Load shedding is typically used to curtail large blocks of customer load (for example, particular distribution feeders) during an under frequency event when demand for electricity exceeds supply (for example, during the sudden loss of a generating unit).

Load Tap Changer (LTC)

A substation controller used to regulate the voltage output of a transformer.

Low Sulfur Fuel Oil (LSFO)

A fuel oil that contains less than 500 parts per million of sulfur; about 0.5% sulfur content.

Low Sulfur Industrial Fuel Oil (LSIFO)

A fuel oil that contains up to 7,500 parts per million of sulfur; about 0.75% sulfur content. LSIFO is used by Maui Electric and Hawaiʻi Electric Light if a fuel with lower sulfur content than MSFO is needed.

Low Voltages

Voltages above 0.9 per unit that are of concern because these voltages can become an under voltage violation in the future.

M

Maalaea Power Plant (MPP)

The largest power plant on Maui, with 15 diesel units, a combined cycle gas turbine, and a combined/simple cycle gas turbine totaling 208.42 MW (net) of firm capacity.

Maintenance Outage

See Outage on page B-23.

MBtu

A thousand Btu. See also British Thermal Unit on page B-3.

Medium Sulfur Fuel Oil (MSFO)

A fuel oil that contains between 1,000 and 5,000 parts per million of sulfur; between 1% and 3.5% sulfur content.

Megawatt (MW)

A unit of power, capacity, or demand equal to one million watts. The Companies typically express their generating capacities and system demand in Megawatts.

Megawatt-hour (MWh)

A unit of electric energy equal to one million watt-hours. The Companies from time to time express the energy output of their generators or the amount of energy purchased from Independent Power Producers in megawatt-hours.

MMBtu

One million Btu. See also British Thermal Unit on page B-3.

Modern Grid

An umbrella term used to describe transformed grid, including communications, AMI, ADMS, and DA.

Must Run Unit

A baseload generation facility that must run continually due to operational constraints or system requirements to maintain system reliability; typically a large thermal power plant.

N

N-1 Contingency

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.

Nameplate Generation

See Generation (Electricity) on page B-14.

Net Capacity

See Capacity, Generating on page B-4.

Net Energy Metering (NEM)

A financial arrangement between a customer with a renewable distributed generator and the utility, where the customer only pays for the net amount of electricity taken from the grid, regardless of the time periods when the customer imported from or exported to the grid. Under a NEM arrangement, the customer is allowed to remain connected to the power grid, so that the customer can take advantage of the grid's reliability infrastructure (such as ancillary services provided by generators, energy storage devices, and demand response programs), use the grid as a "bank" for power generated by the customer in excess of the customer's needs, and use the grid as a backup resource for times when the power generated by the customer is less than the customer's needs.

Net Generation

See Generation (Electricity) on page B-14.

Nitrogen Oxide (NO_x)

A pollutant and strong greenhouse gas emitted by combusting fuels.

Nominal Value (Nominal Dollars)

While a complex topic, at its most basic, value is based on a measure of money over a period of time. Generally expressed in terms of US dollars, nominal value represents a money cost in a given year, usually the current year. As such, nominal dollars can also be referred to as current dollars.

Non-Export Model

A tariff structure governing the interconnection of non-export DG systems.

Non-transmission alternatives

Programs and technologies that complement and improve operation of existing transmission systems that individually or in combination defer or eliminate the need for upgrades to the transmission system.

North American Electric Reliability Corporation (NERC)

An international regulatory authority whose mission is to ensure the reliability of the bulk power system in North America.

O

Off-Peak Energy

Electric energy supplied during periods of relatively low system demands as specified by the supplier. In general, this term is associated with electric water heating and pertains to the use of electricity during that period when the overall demand for electricity from our system is below normal.

On-Peak Energy

Electric energy supplied during periods of relatively high system demand as specified by the supplier.

Operation and Maintenance (O&M) Expense

The recurring costs of operating, supporting, and maintaining authorized programs, including costs for labor, fuel, materials, and supplies, and other current expenses.

Operating Reliability

The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components.

Operating Reserves

There are two types of operating reserves that enable an immediate or near immediate response to an increase in demand. (See also Reserve on page B-28.)

Spinning Reserve Service: Provides additional capacity from electricity generators that are on-line, loaded to less than their maximum output, and available to serve customer demand immediately should a contingency occur.

Supplemental Reserve Service: Provides additional capacity from electricity generators that can be used to respond to a contingency within a short period, usually ten minutes.

Outage

The period during which a generating unit, transmission line, or other facility is out of service. The following six terms are types of outages or outage-related terms:

Forced Outage: The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons or a condition in which the equipment is unavailable due to unanticipated failure.

Forced Outage Rate: The hours a generating unit, transmission line, or other facility is removed from service, divided by the sum of the hours it is removed from service, plus the total number of hours the facility was connected to the electricity system expressed as a percent.

Full-Forced Outage: The net capability of main generating units that is unavailable for load for emergency reasons.

Maintenance Outage: The removal of equipment from service availability to perform work on specific components that can be deferred beyond the end of the next weekend, but requires the equipment be removed from service before the next planned outage. Typically, a Maintenance Outage may occur anytime during the year, have a flexible start date, and may or may not have a predetermined duration.

Partial Outage: The outage of a unit or plant auxiliary equipment that reduces the capability of the unit or plant without causing a complete shutdown. It may also include the outage of boilers in common header installations.

Planned (or Scheduled) Outage: The shutdown of a generating unit, transmission line, or other facility, for inspection or maintenance, in accordance with an advance schedule.

P

Partial Outage

See Outage on page B-23.

Peak Demand

The maximum amount of power necessary to supply customers; in other words, the highest electric requirement occurring in a given period (for example, an hour, a day, month, season, or year). For an electric system, it is equal to the sum of the metered net outputs of all generators within a system and the metered line flows into the system, less the metered line flows out of the system. From a customer's perspective, peak demand is the maximum power used during a specific period of time.

Peaker

A generation resource that generally runs to meet peak demand, usually during the late afternoon and early evening when the demand for electricity during the day is highest. It is also referred to as a peaker plant or a peaking power plant.

Peaking Capacity

See Capacity, Generating on page B-4.

Phase imbalance

A condition in which there is a voltage imbalance across two or more phases of a multi-phase system.

Photovoltaic (PV)

Electricity from solar radiation typically produced with photovoltaic cells (also called solar cells): semiconductors that absorb photons and then emit electrons.

Planned Outage

See Outage on page B-23.

Planning Reserve

See Reserve on page B-28.

Plug-in Electric Vehicle (PEV)

An umbrella term encompassing all electric or hybrid electric vehicles that can be recharged through an external electricity source.

Power

The rate at which energy is supplied to a load (consumed), usually measured in watts (W), kilowatts (kW), or megawatts (MW).

Power Factor

A dimensionless quantity that measures the extent to which the current and voltage sine waves in an AC power system are synchronized. If the voltage and current sine waves perfectly match, the power factor is 1.0. Power factors not equal to 1.0 result in dissipation of electric energy into losses.

Power Generating Technology

The myriad ways in which electric power is produced, including both commercially available technologies and emerging technologies, as well as hypothetical technologies.

Power Purchase Agreement (PPA)

A contract for the Hawaiian Electric Companies to purchase energy and or capacity from a commercial source (for example, an Independent Power Producer) at a predetermined price or based on pre-determined pricing formulas.

Present Value

The value of an asset, taking into account the time value of money—a future dollar is worth less today. Present value dollars are expressed in a constant year dollars (usually the current year). Future dollars are converted to present dollars using a discount rate. For example, if someone borrows money from you today, and agrees to pay you back in one year in the amount of $1.00, and the discount rate is 10%, you would be only be willing to loan the other person $0.90 today. Utility planners use present value as a way to directly compare the economic value of multi-year plans with different future expenditure profiles. Net Present Value is the difference between the present value of all future benefits, less the present value of all future costs.

Primary Lines

The main high-voltage lines of the transmission and distribution network.

Proactive Approach

A forward-looking process governing the forecasting of penetration of DER on distribution circuits, analysis of operational constraints, and pre-emptive mitigation of these constraints.

Public Benefits Fee Administrator (PBFA)

A third-party agent that handles energy efficiency rebates and incentives for the Hawaiian Electric Companies.

Pumped Storage Hydro

See Storage on page B-31.

Q

Qualitative

Consideration of externalities which assigns relative values or rankings to the costs and benefits. This approach allows expert assessments to be derived when actual data from conclusive scientific investigation of impacts are not available.

Quantitative

Consideration of externalities which provides value based on available information on impacts. This approach allows for the quantification of impacts without assigning a monetary value to those impacts (for example, tons of crop loss).

R

Ramping Capability

A measure of the speed at which a generating unit can increase or decrease output.

Rate Base

The value of property upon which a utility is permitted to earn a specified rate of return as established by a regulatory authority. The rate base generally represents the book value of property used by the utility in providing service and may be calculated by any one or a combination of the following accounting methods: fair value, prudent investment, reproduction cost, or original cost. Depending on which method is used, the rate base includes net cost of plant in service, working cash, materials and supplies, and deductions for accumulated provisions for depreciation, contributions in aid of construction, customer advances for construction, accumulated deferred income taxes, and accumulated deferred investment tax credits.

Reactive Power

The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment.

Real Dollars

While a complex topic, at its most basic, value is a measure of money over a period of time. Generally expressed in terms of units of US dollars, real dollars represents the true cost inclusive of inflationary adjustments (such as simple price changes which, of course, are usually price increases). Over time, real dollars are a measure of purchasing power. As such, real dollars can also be referred to as constant dollars.

Recloser

A circuit breaker with the ability to reclose after a fault-induced circuit break.

Reconductoring

The process of replacing the cable or wiring on a distribution or transmission line.

Regulating Reserves

The capacity required to maintain system frequency through fast balancing.

Reliability

The degree of performance of the elements of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply. Electric system reliability can be addressed by considering two basic and functional aspects of the electric system, Adequacy of Supply and System Security. See also System Reliability on page B-33.

Renewable Energy Resources

Energy resources that are naturally replenished, but limited in their constant availability (or flow). They are virtually inexhaustible but are limited in the amount of energy that is available over a given period of time. The amount of some renewable resources (such as geothermal and biomass) might be limited over the short term as stocks are depleted by use, but on a time scale of decades or perhaps centuries, they can likely be replenished.

Renewable energy resources include photovoltaics, biomass, hydroelectric, geothermal, solar, and wind. In the future, they could also include the use of ocean thermal, wave, and tidal action technologies. Utility renewable resource applications include bulk electricity generation, on-site electricity generation, distributed electricity generation, non-grid-connected generation, and demand-reduction (energy efficiency) technologies.

Unlike fossil fuel generation plants (which can be sited where most convenient because the fuel is transported to the plant), renewable energy generation plants must be sited where the energy is available; that is, a wind farm must be sited where a sufficient and relatively constant supply of wind is available. In other words, fossil fuels can be brought to their generation plants whereas renewable energy generating plants must be brought to the renewable energy source.

Renewable Portfolio Standard (RPS)

A goal for the percentage of electricity sales in Hawai'i to be derived from renewable energy sources. The RPS is set by state law. Savings from energy efficiency and displacement or offset technologies are part of the RPS until January 2015, when they will instead be counted toward the new EEPS. The current RPS calls for 10% of net electricity sales by December 31, 2010; 15% of net electricity sales by December 31, 2015; 25% of net electricity sales by December 31, 2020; and 40% of net electricity sales by December 31, 2030.

Repowering

A means of permanently increasing the output and/or the efficiency of conventional thermal generating facilities.

Reserve

There are two types of reserves:

> ***Operating Reserve:*** That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages, and local area protection. See also Operating Reserves on page B-23.

Planning Reserve: The difference between a control area's expected annual peak capability and its expected annual peak demand expressed as a percentage of the annual peak demand.

Reserve Margin (Planning)

The amount of unused available capability of an electric power system at peak load for a utility system as a percentage of total capability. Such capacity may be maintained for the purpose of providing operational flexibility and for preserving system reliability.

Residential Direct Load Control (RDLC)

A demand response program that offers incentives to customers who allow the Hawaiian Electric Companies to install a load control switch on residential electric water heater, so that the load can be curtailed remotely by the utility during times of system need.

Resiliency

The ability to quickly locate faults and automatically restore service after a fault, using FLISR (Fault Location, Isolation, & Service Restoration).

Retail Rate

The rate at which specific classes of customers compensate the utility for grid electricity.

Reverse Flow

The flow of electricity from the customer site onto the distribution circuit or from the distribution circuit through the substation to higher voltage lines. Also called backfeed.

Rule 14H

The Hawaiian Electric Company rules governing service connections and facilities on a customer's premises.

Rule 18

The Hawaiian Electric Company rules governing Net Energy Metering.

S

Schedule Q

The tariff structure that governs Hawaiian Electric purchases from qualifying facilities 100kW or less

Scheduled Outage

See Outage on page B-23.

Secondary Lines

Low voltage distribution lines directly serving customers.

Service Charge

A fixed customer charge intended to allocate the cost of servicing the grid to all customers, regardless of capacity needs.

Service Level Issue

Any issue arising at the point of service provision to customers, including traditional utility service and grounding transformer overloads caused by DG PV.

Service Transformer

A transformer that performs the final voltage step-down from the distribution circuit to levels usable by customers.

Simple-Cycle Combustion Turbine (SCCT)

A generating unit in which the combustion turbine operates in a stand-alone mode, without waste heat recovery.

Single-Train Combined Cycle (STCC)

See Combined Cycle on page B-5.

Small Business Direct Load Control (SBDLC)

A demand response programs that allows the electric utility to curtail load without intervention of an operator at the end user's (customer's) premises. For example, the utility may install a load control switch on an electric water heater or air-conditioning unit, so that the load can be controlled remotely by the utility during times of system need.

Smart Grid

A platform connecting grid hardware devices to smart grid applications, including VVO, AMI, Direct Load Control, and Electric Vehicle Charging.

Smart Inverter Working Group (SIWG)

A working group created by the California Public Utilities Commission to propose updates to the technical requirements of inverters.

Spinning Reserve Service

See Operating Reserves on page B-23.

Standard Interconnection Agreement (SIA)

Rules governing interconnection of distributed generation systems.

Standby Charge

A fixed charge intended to recover significant backup generation facilities the utility must maintain to ensure grid reliability in the event of widespread DG outages.

Static VAR Compensator

A device used provide reactive power in order to smooth voltage swings.

Steady-State Conditions

Conditions governing normal grid operations; contrasted with transient conditions.

Steam Turbine (ST)

A turbine that is powered by pressurized steam and provides rotary power for an electrical generator.

Storage

A system or a device capable of storing electrical energy to serve as an ancillary service resource on the utility system and/or to provide other energy services. Three major types of energy storage are relevant for consideration in Hawaiʻi:

Battery: An energy storage device composed of one or more electrolyte cells that stores chemical energy. A large-scale battery can provide a number of ancillary services, including frequency regulation, voltage support (dynamic reactive power supply), load following, and black start as well as providing energy services such as peak shaving, valley filling, and potentially energy arbitrage. Also referred to as Battery Energy Storage System (BESS).

Flywheel: A cylinder that spins at very high speeds, storing rotational kinetic energy. A flywheel can be combined with a device that operates either as an electric motor that accelerates the flywheel to store energy or as a generator that produces electricity from the energy stored in the flywheel. The faster the flywheel spins, the more energy it retains. Energy can be drawn off as needed by slowing the flywheel. A large flywheel plant can provide a number of ancillary services including frequency regulation, voltage support (dynamic reactive power supply), and potentially spinning reserve.

Pumped Storage Hydro: Pumped storage hydro facilities typically use off-peak electricity to pump water from a lower reservoir into one at a higher elevation storing potential energy. When the water stored in the upper reservoir is released, it is passed through hydraulic turbines to generate electricity. The off-peak electrical energy used to pump the water uphill can be stored indefinitely as gravitational energy in the upper reservoir. Thus, two reservoirs in combination can be used to store electrical energy for a long period of time, and in large quantities. A modern pumped-storage facility can provide a number of ancillary services, such as frequency regulation, voltage support (dynamic reactive power), spinning and non-spinning reserve, load following and black start as well as energy services such as peak shaving and energy arbitrage.

Sulfur Oxide (SO_x)

A precursor to sulfates and acidic depositions formed when fuel (oil or coal) containing sulfur is combusted. It is a regulated pollutant.

Substation

A small building or fenced in yard containing switches, transformers, and other equipment and structures for the purpose of stepping up or stepping down voltage, switching and monitoring transmission and distribution circuits, and other service functions. As electricity gets closer to where it is to be used, it goes through a substation where the voltage is lowered so it can be used by customers such as homes, schools, and factories.

Substation Transformer

Substation-sited transformers used to change voltage levels between transmission lines, or between transmission lines and distribution lines.

Supervisory Control and Data Acquisition (SCADA)

A system used for monitoring and control of remote equipment using communications networks.

Supplemental Reserve Service

See Operating Reserves on page B-23.

Supply-Side Management

Actions taken to ensure the generation, transmission, and distribution of energy are conducted efficiently. Supply-side generation includes generating plants that supply power into the electric grid.

Switching Station

An electrical substation, with a single voltage level, whose only functions are switching actions.

Synchronous Condensers

Devices used to modulate the voltage or power factor of transmission lines. Synchronous condensers typically provide dynamic reactive power support, and are deployed only where dynamic reactive power support needs to be maintained at a particular location.

System

The utility grid: a combination of generation, transmission, and distribution components.

System Average Interruption Duration Index (SAIDI)

The average outage duration for each customer served. A reliability indicator.

System Average Interruption Frequency Index (SAIFI)

The average number of interruptions that a utility customer would experience. A reliability indicator.

System Reliability

Broadly defined as the ability of the utility system to meet the demand of its customers while maintaining system stability. Reliability can be measured in terms of the number of hours that the system demand is met.

System Security

The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

T

Tariff

A published volume of rate schedules and general terms and conditions under which a product or service will be supplied.

Thermal Loading

The maximum current that a conductor can transfer without overheating.

Time-of-Use (TOU) Rates

The pricing of electricity based on the estimated cost of electricity during a particular time block. Time-of-use rates are usually divided into three or four time blocks per twenty-four hour period (on-peak, mid-peak, off-peak and sometimes super off-peak) and by seasons of the year (summer and winter). Real-time pricing differs from TOU rates in that it is based on actual (as opposed to forecasted) prices which may fluctuate many times a day and are weather-sensitive, rather than varying with a fixed schedule.

Total Resource Cost (TRC)

A method for measuring the net costs of a conservation, load management, or fuel substitution program as a resource option, based on the total costs of the program, including both the participants' and the utility's costs.

Transformer

A device used to change voltage levels to facilitate the transfer of power from the generating plant to the customer. A step-up transformer increases the voltage (power) of electricity while a step-down transformer decreases it.

Transient Condition

An aberrant grid condition that begins with an adverse event and ends with the return to steady-state conditions (stable voltage, connection of all loads).

Transient Over Voltage (TrOV)

A transient issue characterized by a sudden spike in voltage above steady-state conditions on a circuit, or on a subset or component of a circuit.

Transmission and Distribution (T&D)

Transmission lines are used for the bulk transfer of electric power across the power system, typically from generators to load centers. Distribution lines are used for transfer of electric power from the bulk power level to end-users and from distributed generators into the bulk power system. In the Hawaiian Electric Companies, standard transmission voltages are 138,000 volts (Hawaiian Electric system only) and 69,000 volts (Hawaiian Electric, Maui Electric, Hawai'i Electric Light). Distribution voltage is 23,000 volts (Maui Electric) and 13,200 volts (all systems).

Transmission System

The portion of the electric grid the transports bulk energy from generators to the distribution circuits.

Two-Way Communications

The platform and capabilities that are required to allow bi-directional communication between the utility and elements of the grid (including customer-sited advanced inverters), and control over key functions of those elements. The platform must contain monitor and control functions, be TCP/IP addressable, be compliant with IEC 61850, and provide cyber security at the transport and application layers as well as user and device authentication.

U

Ultra Low Sulfur Diesel (ULSD)

A diesel fuel that contains less 15 parts per million of sulfur.

Under Frequency Load Shedding (UFLS)

A system protection scheme used during transient adverse conditions to balance load and generation.

Under Voltage Load Shedding (UVLS)

A system protection scheme used during low voltage conditions to avoid a voltage collapse.

Under Voltage Violation

Bus voltage less than 0.9 per unit.

United States Department of Defense (DOD)

An executive department of the U.S. government responsible for coordinating and supervising all agencies and functions of the Federal government that are concerned directly with national security and the armed forces.

United States Department of Energy (DOE)

An executive department of the U.S. government that is concerned with the United States' policies regarding energy, environmental, and nuclear challenges.

United States Environmental Protection Agency (EPA)

An executive department of the U.S. government whose mission is to protect human health and the environment.

University of Hawai'i Economic Research Organization (UHERO)

The economic research organization at the University of Hawai'i, which is a source for information about the people, environment, and Hawai`i and the Asia-Pacific economies, including energy issues.

V

Variable Renewable Energy

A generator whose output varies with the availability of it primary energy resource, such as wind, the sun, and flowing water. The primary energy source cannot be controlled in the same manner as firm, conventional, fossil-fuel generators. Specifically, while a variable generator (without storage) can be dispatched down, its output cannot be guaranteed 100% of the time when needed. However, the primary energy source may be stored for future use, such as with solar thermal storage, or when converted into electricity via storage technologies. Also referred to as intermittent and as-available renewable energy.

Voltage

Voltage is a measure of the electromotive force or electric pressure for moving electricity.

Voltage Collapse

The sudden and large decrease in the voltage that precipitates shutdown of the electrical system.

Voltage Regulation

A measure of change in the voltage magnitude between the sending and receiving end of a component, such as a transmission or distribution line.

Voltage Regulator Controller

A device used to monitor and regulate voltage levels.

Volt/VAR control

Control over voltage and reactive power levels.

Volt/VAR Optimization (VVO)

The process of monitoring voltages at customer premises through an AMI system, and optimizing them using reactive power control and voltage control capabilities.

W

Watt

The basic unit of measure of electric power, capacity, or demand. It is a derived unit of power in the International System of Units (SI), named after the Scottish engineer James Watt (1736–1819).

C. Modeling Analyses Methods

Three teams conducted independent modeling analysis for produce the results presented in the PSIP. The teams included Hawaiian Electric Company generation planning, Black & Veatch, and PA Consulting. Each team employed a different modeling analysis method. In additional, Electric Power Systems employed a grid simulation model to conduct its system security studies.

Each of these four modeling methods are presented.

GRID SIMULATION MODEL FOR SYSTEM SECURITY ANALYSIS

The Transmission Planning Division of Hawaiian Electric Company uses the Siemens PSSE (Version 33) Power-Flow and Transient Stability program for transmission grid modeling and for system security analysis. This program is one of three most commonly used grid simulation programs in United States utilities. The program supports the IEEE (Institute of Electric and Electronic Engineer) generic models for generators and inverters. When available, custom models can preclude generic models.

PSSE is high-performance transmission planning software that has supported the power community with meticulous and comprehensive modeling capabilities for more than 40 years. The probabilistic analyses and advanced dynamics modeling capabilities included in PSSE provide transmission planning and operations engineers a broad range of methodologies for use in the design and operation of reliable networks. PSSE is used for power system transmission analysis in over 115 countries worldwide.

The program has two distinct program models: (1) power flow to represent steady state conditions and (2) stability to represent transients caused by faults and rapid changes in generation. The transient conditions are modeled to about 10 seconds after which most system will stabilize or fail.

After major system disturbances, we use this program to verify the system events as well as to verify the modeling assumptions.

Input to this program includes impedances for all the transmission lines, transformers, and capacitors; detailed information of the electrical characteristics of all generators and inverters (including PV panels and wind turbines); and energy storage devices (such as batteries). The model includes relays for fault clearing and under-frequency load shedding (UFLS).

Electric Power Systems used the PSSE model to conduct its robust and detailed system security studies because the model allows rapid and consistent sharing of data.

HAWAIIAN ELECTRIC: P-MONTH MODELING ANALYSIS METHODS

The Companies used computer models for the PSIP analyses. Production costs of the operating the system is simulated using the P-Month hourly production simulation model. The model is populated with unit data to characterize the resources operating on the system at all hours so that the performance and cost of the system can be evaluated for various future cases. The data from the hourly production simulation model is processed using other internally developed tools to evaluate the results of the simulations.

P-MONTH Hourly Production Simulation Model

Thermal Generation Modeling

The model, P-MONTH, is an hourly production simulation program supplied by the P Plus Corporation (PPC). This model simulates the chronological, hour-by-hour operation of the generation system by dispatching (mathematically allocating) the forecasted hourly load among the generating units in operation. Unit commitment and dispatch levels are based on fuel cost, transmission loss (or "penalty") factors, and transmission system requirements. The load is dispatched by the model such that the overall fuel expense of the system is minimized (that is, "economic dispatch") within the constraints of the system. The model calculates the fuel consumed using the unit dispatch described above, based on the load carried by each unit and the unit's efficiency characteristics. The total fuel consumed is the summation of each unit's hourly fuel consumption.

Variable Generation Modeling

The model calculates the energy produced by renewable resources and other variables using an 8760 hourly profile. This profile is constructed based on historical observed output from in service variable generation or from solar irradiance profiles and measured wind potential for future variable generation. Generation that is produced according to this hourly profile that cannot be accommodated on the system in any one hour will be curtailed per the curtailment order. The curtailment order follows a last in, first out rule whereby the last installed variable renewable resource will be curtailed first, that is, reverse chronological order.

Unit Forced Outage Modeling

The production simulation model can be used by applying one of two techniques: probabilistic or Monte Carlo. Using the probabilistic technique, the model will assume generating units are available to operate (when they are not on overhaul) at some given load that is determined by their normal top load rating and forced outage rate. By this methodology, the units will nearly always be available at a derated capacity that has been reduced to account for the forced outage rate.

PMONTH has a Monte Carlo Simulation option in which random draws are used to create multiple scenarios (iterations) to model the effect of random forced outages of generating units. Each scenario is simulated individually; the averages of the results for all the scenarios represent the expected system results. This Option provides the most accurate simulation of the power system operations if sufficient number of scenarios are used. However, the computer run time can be long if many scenarios are run. The number of scenarios needed to establish a certain level of confidence in the results depends on the objectives of the user and the size of the system. Normally, the system production cost will converge sufficiently between 20 and 30 iterations.

Using the Monte Carlo, or deterministic, technique, forced outages for generating units are treated as random, discrete outages in one week increments. The model will randomly take a generating unit out of service (during periods when it is available) up to a total forced outage time of 5%. By this methodology, the unit can operate at normal top load for 95% of the time when it is not on overhaul but will not be able to operate (that is, will have a zero output) for 5% of the time when it is not on overhaul. For the PSIP, the modeling will use the Monte Carlo methodology to capture the forced outages of all thermal units.

Demand Response Modeling

Demand response programs were modeled to provide several benefits including capacity deferral and regulating reserve. Programs that provide capacity were included in the capacity planning criteria analysis assessment. Programs that provide regulating reserve ancillary services were included in the modeling.

Energy Storage Modeling

The benefits of energy storage for system contingencies are captured in the system security modeling. Regulating reserves were provided by a combination of energy storage and thermal generation. Load shifting was modeled as a scheduled energy storage resource. The roundtrip efficiency was accounted for in the charging of this resource. The charging schedule was optimized to coincide with the hours in which curtailment occurred or the profile of PV energy during the day to minimize day time curtailment. The discharging schedule coincided with the evening peak.

System Security Requirements

The system security requirements were met by including the regulating and contingency reserve capabilities of demand response, energy storage, and thermal generation in the modeling. The system security requirements depend on the levels of PV and wind on the system. The regulating reserve requirements were changed hourly in the model to reflect the dynamic changes in levels of PV and wind throughout the day. Curtailed energy from controllable PV and future wind resources contributed to meeting the regulating reserve requirement. The contingency reserve requirements were changed annually to reflect the largest unit contingency on the system.

Sub-Hourly Model

The P-Month model is an hourly chronological model. Sub-hourly modeling cannot be done using this model. The Companies developed a limited sub-hourly model to assess the any value that the hourly model was not able to capture compared to the modeling sub-hourly when batteries, and other resources that operate like batteries, are on the system.

Key Model Inputs

In addition to the system changes described in the Base Plan, there are several key assumptions that are required for modeling:

1. Energy and hourly load to be served by firm and non-firm generating units
2. Load carrying capability of each firm generating unit
3. Efficiency characteristics of each firm generating unit
4. Variable O&M costs
5. Operating constraints such as must-run units or minimum energy purchases from purchased power producers
6. Overhaul maintenance schedules for the generating units
7. Estimated forced outage rates and maintenance outage rates
8. Regulating reserve requirements
9. Demand response and energy storage resources
10. Fuel price forecasts for fuels used by generating units

Methodology for Post-Processing of Production Simulation Results

Key Outputs

Some of the key outputs from the model are as follows:

1. Generation produced by each firm generation units
2. Generation accepted into the system by non-firm generating units
3. Excess energy not accepted into the system (curtailed energy)
4. Fuel consumption and fuel costs
5. Variable and fixed O&M costs
6. Start-up costs

Post-Processing

The outputs from the model are post-processed using Excel to incorporate the following:

1. Capital costs for new generating units, renewable and energy storage resources, allocated based on capital expenditure profiles
2. Capital costs for utility projects such as fuel conversions or the retirement of existing utility generating units
3. Payments to Independent Power Producers (IPP) for purchased power, including Feed in Tariff projects
4. Fixed O&M for future energy storage resources

All costs are post-processed into annual and total dollars to be used in the Financial Model. All annual, total, and present value (2015$) revenue requirements are also post-processed for use in evaluating the different plans but are not meant to be the "all-in costs" that the Financial Model will be doing. Revenue requirements are characterized as utility and IPP. Utility revenue requirements are categorized into fuel, fixed O&M, variable O&M, and capital. IPP revenue requirements are categorized into capacity and energy payments. Using the revenue requirements from post-processing, plans can be analyzed according to several key metrics.

Key Metrics

The key metrics analyzed through post processing of the model data are as follows:

1. Differential accumulated present value of annual revenue requirements
2. Differential rate impact
3. Monthly bill impact
4. Total system curtailment
5. Renewable Portfolio Standards (RPS)
6. Gas consumption
7. Utility CO_2 emissions
8. Annual Generation Mix
9. Daily Generation Mix by Hour

Lana'i & Moloka'i Modeling

The model used in the analysis for Lana'i and Moloka'i is an Excel based model focusing on meeting the total sales (energy) forecasted for each year. In this way the amount of energy produced from each resource was assumed to be taken regardless of any profiles. This simplified model shows results that are directionally correct.

The model calculations are broken up into three pieces: existing power purchase agreements, future renewable resources, and utility generation. First, it is assumed that the utility generation will provide a minimum amount of generation for system reliability. Second, the existing power purchase agreements fill in additional energy based on historical purchases. Lastly, future resources can be added to get as close to the total sales as possible. If the total energy provided by the three pieces is less than forecasted sales for a particular year, the utility generation will increase to make up the difference. If the total energy is greater than forecasted sales then the excess is curtailed from newly added resources.

The model will track all costs associated with fuel expense, O&M, capital, and power purchased payments to give annual revenue requirements and total net present value (NPV) consistent with the analysis for the other islands. Similarly, the model will also calculate the Renewable Portfolio Standards (RPS) percent for each year of the plan.

The utility generation component allows for different fuels to be assigned to the units as well as splitting the fuel types as necessary. Fuel usage and associated costs are calculated for each year.

Future renewable resources are identified by the year of installation as well as ownership (for example, utility or IPP). Resource ownership determines the capital expenditures patterns. Either a levelized profile or a declining profile to match company revenue requirements is used in the analysis. Costs for O&M and applicable fuel costs for each year are calculated for the new resources.

PA CONSULTING: PRODUCTION COST MODELING

PA Consulting Group (PA) performed hourly and sub-hourly production cost modeling to support the Hawaiian Electric Companies' development of the PSIPs. The production cost modeling was conducted using the EPIS AURORAxmp software. AURORA is an hourly chronological dispatch model used to model electricity markets. The model has broad capabilities. The primary forecasting capabilities that we used in the model are least cost dispatch and long-term capacity expansion modeling.

The capacity expansion model is an optimization model that determines the most cost effective long-term generation expansion and retirement schedules, based upon assumptions regarding capital costs, operating costs, and operational constraints, as well as system constraints such as reserve margins and spin requirements. The most cost effective plan is based upon the solution with the lowest net present value.

The chronological dispatch model determines the least-cost solution for dispatching resources, including demand side resources, to meet load and reserve margin requirements. The dispatch solution honors individual generator constraints and factors in marginal dispatch costs, including fuel and O&M. Each resource is modeled individually, taking into account the unit-specific cost and operating characteristics. Units are dispatched in the simulation in the order of economic merit (according to dispatch cost) until adequate generation is brought on line to meet the load. The model factors in out-of-merit dispatch due to must-run and must-take requirements. The model also curtails resources if the constrained generation exceeds demand.

The sub-hourly modeling was structured to address the Commission's interest in utilizing sub-hourly modeling to more fully investigate issues raised in the April 28th D&Os. These issues include evaluation of the value of DR and DG in the context of the Company's vision for the future of the utility, and consideration of resources required to support the integration of more intermittent renewable generation resources, and to reduce curtailments where it is economic to do so.

Specifically, PA used the sub-hourly modeling to identify any periods with unserved energy or periods with significant potential for renewable energy curtailment. We evaluated whether changing the resource mix can cost effectively address these issues. This assessment was conducted using iterative analyses to identify whether changing the available resource mix will reduce curtailment or dispatch costs.

AURORA was used to both evaluate a least-cost capacity expansion and retirement plan, and also to model scenarios of alternative resource plans in order to identify the incremental costs associated with alternative policies.

Key Inputs

PA worked with Hawaiian Electric Resource Planning and Black & Veatch to develop a common set of assumptions for the modeling initiative. These assumptions include:

- Resource characteristics (such as capacity, heat rates, ramp rates, minimum-up times, and minimum-down times)
- Characteristics of demand response programs
- Fuel costs
- Types of fuel that each fossil generator will use
- Identification of timing and generators that would be converted to burn LNG
- Fixed and variable operating costs
- Capital costs necessary to extend the life of existing generation
- Costs for new generation technologies (capital and operating)
- Availability of new generation resources (timing and capacities)
- System load forecasts
- Production profiles for variable energy resources.

Hourly Production Cost Modeling

Generation and demand side resources are dispatched to serve the system load. The base case simulations reflect the current configuration in which each island is a stand-alone system.[1] Units with low operating costs relative to other facilities are dispatched often; units with high costs are dispatched less frequently. The hourly dispatch logic is based upon short-run marginal generation costs, which include: fuel costs, variable operating costs, start-up costs, and emission costs. In contrast, the long-term retirement and expansion plan considers all costs rather than just marginal costs. The additional costs in the long run optimization include fixed O&M costs and capital costs.

The hour-by-hour interaction of supply and demand determines how frequently plants are dispatched within a market. The model incorporates logic for a variety of constraints that are incorporated into the least-cost dispatch logic. These constraints include: must-run requirements, minimum load requirements, ramp times, minimum uptimes, and minimum downtimes. The model also includes planned maintenance schedules and forced outage rates. The determination of the least-cost dispatch, subject to constraints, is based upon the model, assuming perfect information about future hourly loads.

PA used an iterative process to develop the preferred PSIP for each island. Our first step was to represent the existing systems within the model and develop simulations for the

[1] A case was run with a 200 MW DC transmission cable connecting the islands of O'ahu and Maui.

first two years. We used these simulations to calibrate the models to reasonably represent how the current power systems dispatch and to capture the current generation operating costs, fuel costs, and purchase power agreements. We then used the optimization model to develop a least cost base case that factored in constraints related to committed generation retirements, assumptions about future levels of distributed generation, and availability of new generation resources. In the third stage of our analysis we tested alternative scenarios to examine the incremental costs of alternative power supply plans. The analysis in the third stage was based upon modeling specific scenarios over the 2015–2030 time horizon and did not use the long-term resource optimization feature.

Sub-Hourly Production Cost Modeling

The purpose of the sub-hourly modeling was to gain insights regarding ramp constraints, identify potential issues with large amounts of variable supply resources, and identify the potential value of fast response resources, including demand response resources. We use sub-hourly modeling to identify any periods with unserved energy or high frequency, and amounts of renewable energy curtailment. We then assess whether changing the resource mix can cost effectively address these issues.

The sub-hourly modeling was conducted with the previously described production cost model. In order to develop the sub-hourly analysis, it was necessary to convert all the hourly generation and variable supply resource profiles into five-minute profiles. We did not change any assumptions about fuel costs or generator constraints. A brief description of the process for developing the five-minute profiles follows.

We started with available one-minute historic net load profiles, wind production profiles, and solar production profiles. We developed a one-minute gross load profile from the one-minute profiles into five-minute profiles using averages of the five-minute periods. In instances where we did not have sub-hourly data, such as for hydro generation, we assumed that the generation was constant over the one hour period.

PA modeled four days per month at the five-minute level, rather than every day, due to the large amounts of data associated with five-minute modeling. The four representative days included a mid-week weekday (Monday–Thursday), a Friday, and each week-end day.

An overview of PA's sub-hourly modeling methodology follows. This modeling will be conducted at the five-minute intervals.

1. Development of Sub-Hour Modeling Assumptions and Data Inputs

We based inputs to the sub-hourly model on the assumptions agreed upon for the hourly model (fuel costs, generator characteristics, and load forecast) and on one-minute data.

The one-minute data include historic net load profiles, wind production profiles, and solar production profiles. In addition, PA incorporated input from parallel tasks related to development of DG and DR unit characteristics and cost options, as well as how that analysis should be integrated into the sub-hourly chronological dispatch modeling. PA closely coordinated these efforts with the company to ensure that the modeling assumptions and scenarios modeled are consistent with the Company's strategic vision.

2. Translation of Hourly Model Assumptions/Inputs to Five-minute Data

The vast majority of assumptions and inputs used for hourly modeling were used directly in the 5-minute modeling. These include fuel costs, resource capacities and efficiencies, and resource variable operating costs, as well as system operating reserve requirements. In some cases, dynamic information such as resource ramp rates and other time dependent assumptions were adjusted to correspond to the five-minute modeling interval, so that the inputs were correctly incorporated in to the model's economic dispatch algorithms.

3. Development of Five-minute Profiles for Modeling Inputs

We converted renewable generation production profiles from one-minute to five-minute data, and converted the hourly load forecasts to five-minute profiles using the historic one minute load profiles. The conversion ensured consistency between the hourly, one-minute, and five-minute data sets.

Renewable Generation Profiles. Five-minute profiles for wind and solar were constructed from available one-minute data. PA analyzed the one-minute data to develop representative five-minute shapes for typical days in each month. The representative five-minute shapes were not limited to simple averages of one-minute renewable output levels across days, but were structured to represent the extent of variation that exists at the one minute level. There was only one one-minute wind and solar profile per island so all solar and wind resources on each island used the common wind / solar profile. The capacity of the individual units were adjusted so that over a year the total production matched each unit's characteristics.

Load Shape and Distributed Generation Profiles. The derivation of the five-minute load shape profiles required a different analysis, since existing load data reflect behind-the-meter generation. Given time limitations, PA utilize an Excel-based model to construct five-minute load shapes for future years. Future load shapes were based on the current five-minute system load shape and the hourly load forecasts. PA used the five-minute PV production shape and penetration estimates for behind-the-meter solar to allocate the hourly loads into five-minute blocks representing gross system loads (without behind-the-meter generation) and net system loads for future years.

4. Sub-Hourly Model Development and Calibration

PA modeled four days per month at the five-minute level. We did not model all days due to the large amount of data at the five-minute level, and array limitations in the AURORAxmp software. The four representative days included a mid-week weekday (Monday–Thursday), a Friday, and each week-end day. Depending on model run-times and post processing efforts, PA either weighted the midweek day to represent four days, or performed additional simulations to capture a typical week per month to facilitate developing aggregate annual results.

PA developed and validated sub-hourly generation dispatch models for the Maui, O'ahu, and Hawai'i Island systems. Since AURORAxmp is currently configured for hourly modeling, PA had to adjust input parameters to facilitate five-minute modeling. PA adjusted input parameters so that each standard Aurora model hour is interpreted as a five-minute period. Hence, each representative day consisted of 288 standard Aurora model hours. Each representative day was modeled independently, and the standard Aurora model hourly output was aggregated through post processing to produce results for the day.

PA conducted a calibration exercise to verify that the model results made sense in the context of the sub-hourly modeling. We also verified that the sub-hourly modeling results are logical and reasonable, based upon PA's expertise and based upon consultation with generation planning and generation operations staff expertise within the Company. After the results were validated for each system, PA executed simulations of the representative, P5, and P95 cases for each system. Annual system costs and performance metrics were calculated for each set of system conditions.

The simulations provided insights into the resource requirements necessary to meet load requirements with a mix of intermittent and non-intermittent resources. PA used the hourly simulations to capture the full capital and fixed operating costs for the purposes of estimating the total generation system operating costs at the annual level.

BLACK & VEATCH: ADAPTIVE PLANNING MODEL

Black & Veatch is applying its Adaptive Planning Framework to support the PSIP. Adaptive planning provides a framework for modeling complex systems, exploring options (and impacts of constraints), and comparing such options across varying metrics. Key metrics or outcomes would be costs, annual capital commitment required, degree of renewable penetration (capacity, energy served), and system reliability.

The Adaptive Planning Framework manages the overall calculation and cost accounting process. PSIP-specific requirements will be directly addressed by configuring the model:

- Dispatch methodology defined by collective Hawaiian Electric team, based on legal mandates, operational protocols, and defined reserve margins.
- Dispatch models and algorithms tailored to address system constraints (safety, security), loading or ramping criteria defined by Hawaiian Electric by asset class, battery charge, and discharge protocols by size and class of battery, among others.
- Repair times by asset class for projected failures and scheduled outages.
- Full cost accounting of all power supply elements by asset class, nature of cost, and other factors.

Different solution approaches can be applied in adaptive planning. As configured for this plan, the dispatch and economic models do not optimize capacity additions directly, as we believe that there are number of factors and complexities that dictate technology strategies and paths that need to be "engineered". We have, rather, focused on leveraging the model to evaluate alternate technology and capacity plans, including the adequacy of these plans to meet reserve margin or cause curtailment.

For this particular problem, given the complexity, the number of constraints, and the need to consider system security and reliability thresholds in each period, we have elected to apply the following:

- In concert with Hawaiian Electric and PA Consulting, define the general characteristics of base "path" based on central strategy and glide-path analysis. This will define some key initial assumptions regarding technology choice, timing, and retirements.
- Based on this analysis, the B&V team will then define alternative technology mixes or paths that need to be investigated; the focus would be to improve economics, flexibility, grid resiliency, or other factors based on our assessment of year-to-year unit commitment and dispatch data; this effort will also directly explore roles and penetration of battery assets over time.

- The team will generate sensitivities for each path (base and alternative) to stress test results; key variables that can be considered would be aggregate demand by system, the amount of spinning reserves over time (by year coincident with asset mix and by hour to address night-time or off-peak versus peak requirements), timing of capital investments, technology flips (battery versus pumped storage, battery versus thermal for contingency, etc.), timing of retirements, etc.

We believe that this approach maximizes our ability to provide visibility into results and key assumptions, as needed to define optimal PSIP path. It will also allow for direct comparison of decisions and timing that will be critical for Hawaiian Electric in subsequent steps to refine financial engineering of overall rates. Given the short time frame of this study, we do not plan on directly integrating a regulatory or rate model with AP framework, but would work with Hawaiian Electric to apply results of our work within existing spreadsheet models to enable analysis of investment requirements and the nature of investments over the evaluation period.

Economic results will be driven, in part, by market forecasts for fuel (oil, LNG, etc.). The Black & Veatch framework provides robust scenario analysis that will be applied in this case to evaluate:

- Mix and timing of renewable and energy storage assets
- Timing of retirements
- Timing and nature of new generation additions
- Timing and nature of participation from IPPs
- System characteristics
- Reliability risk based on level of investment and intensity of asset type
- Alternate views of costs including market price of fuel, the cost of implementing technology, etc., as needed to address increasingly higher degree of renewable penetration over time.

Economics can be applied in different forms within the model. We can consider:

- Direct capital investment in year of investments driven by project S-curves.
- Levelized costs based on spread of CAPEX and other related costs into an equivalent annual annuity.
- RRF schedule. Capital can be spread and factors can be assigned based on RRF input schedules.
- Third-party contract (IPP, DR, etc.) where the energy or service can be contracted on $/MWh, $/MW, or combination.

Model outputs will be populated within spreadsheets and data viewers to enable direct analysis and comparison (between cases) of:

- Period values by asset; periods can be either 1-hour or 5-minute for PSIP. We will also consider a smaller segment of 1-minute data to test impacts on wind and solar dispatch and spin. Detailed results would include dispatch MW, costs (capital, VOM, FOM), contribution to renewable, and role (contingency, regulation, energy, etc.)
- Aggregated results by asset; basically the same output as available for the period would be available for the asset by year and overall.
- Typical "daily" or 24-hour view; this view would analyze data for each asset by hour in day resulting from dispatch by asset by year. This will allow us to validate the overall dispatch approach, as well as better characterize roles of units. Values calculated would include average, min, max, and standard deviation. This will provide insights into rationale for IPP energy supply schedules for assets that are not anticipated to be owned by Hawaiian Electric.

Time Slice Model within Adaptive Planning Framework.

At the heart of the Adaptive Planning framework is a direct solution mathematical framework that enables direct analysis and "integration" of asset performance and aggregate match of resources to demand (as depicted in the figure below) contribution by asset, aggregate reliability, and costs.

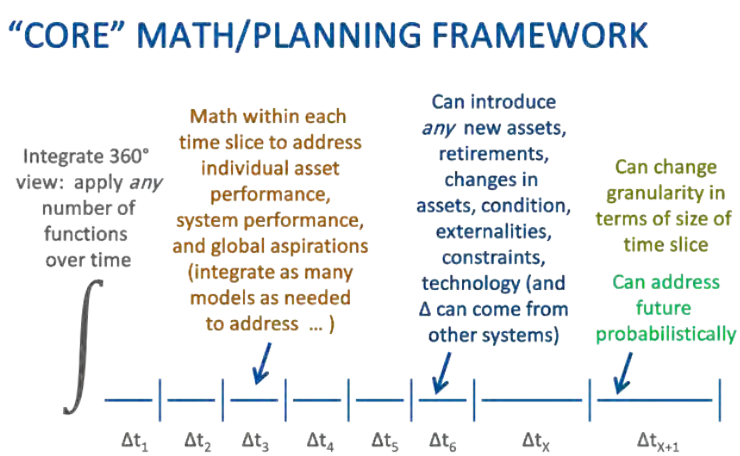

Figure C-1. Black & Veatch Mathematical Modeling Framework

Within the framework, each time slice affords the opportunity for us to:

- Introduce new assets, retire assets, change characteristics (simulate planned outages, etc.).
- Commit assets based on availability, renewable and non-renewable, and economics.

- Incorporate assumptions for wind and solar variability for that particular time slice based on perturbations of the historical wind and solar patterns.
- Incorporate rules for utilizing DG as must-take resource versus curtailable resource.
- Dispatch assets based on protocol and security, and economics including use of DR and energy storage to address ramping or smoothing, forced outages of committed assets, etc.
- Identify boundary conditions (from time slice to time slice) that serve as the basis for evaluating the next time slice; there are a number of instances where actions (such as a start of a 10-minute or 30-minute reserve resource within a particular time slice) will require forward commitment across time slices.

The time slice model works in conjunction with the economic dispatch model to evaluate the situation in the current period and translate this information to subsequent affected time slices. Each time slice considers (takes as input) for each power source:

- Status (available, scheduled outage, forced outage, retired, etc.)
- Operating efficiency
- Fuel characteristics (if applicable)
- Consumable unit costs
- Revenue requirements for capital expenditure

Each time slice also considers demand, adjusted for DR load shaping programs and, as applicable, DG PV. With this information, the time slice model determines:

- Status applicable to next time slice
- Consumable requirements
- Operating costs

The information generated is available at the time-slice or less granular resolution, for example, hourly, monthly, or annually. In addition, the asset hierarchy allows data to be viewed for each power source or aggregated across sources. Capital costs and other outputs associated with those investments would be tabulated by calendar year or other time domain, as required.

Generation Dispatch Methodology

The dispatch model will be used to set the electrical generation outputs to satisfy the electrical demand at the lowest cost while also satisfying system constraints (constrained optimization). These constraints will include system stability (must-run units), minimum downtime and uptime constraints, spinning and non-spinning reserve margin requirements, and non-dispatchable renewable generation. The model will use the following data:

- Variable costs and start-up costs for electrical generation assets
- Ramp rates, minimum downtime, and minimum uptime for electrical generation assets
- Historical reliability and maintainability (MTBF, MTTR) data for all generation assets
- Solar and wind penetration forecast (by time step resolution)
- Solar and wind forecasts (by time step resolution)
- Demand forecasts (by time step resolution)
- System losses

Demand response will be factored into this model via two forms: 1) change in overall "demand" curve as influenced by time-of-day pricing and 2) modeling of specific DR programs.

Energy storage is applied as a resource to supply capacity, regulation, contingency, and other ancillary services associated with frequency response and security. Energy storage added to supply capacity, regulation, or contingency will be modeled via the dispatch model; energy storage added to frequency response will be considered as a cost component of the overall system.

Sub-Hourly Model

Traditional hourly modeling does not expose the operational transients that must be managed during real-time operation of the electric grid. Hence, traditional hourly modeling also does not expose potential value (economic and risk mitigation value, for example) that one set of assets may have over another set of assets, as all transients are softened. Sub-hourly modeling will expose some of this value to support the optimum resource selection that does not violate policy considerations (risk tolerance, renewable goals, budget constraints, fuel diversity, etc.)

Similar to an hourly modeling approach, the sub-hourly model will calculate both commitment (what units are generating power) and dispatch (MW contribution of each asset to the target load) but now at a sub-hourly time step. Maximum daily rate of change will be greater and ramp rate constraints will be hit more often, thereby potentially changing the economic outcome of the simulation as compared to the hourly model. The hourly model assumes dispatch and commitment set points that do not violate any constraints when the time step is one hour, but when the truer transient nature is exposed at the sub-hourly time step, some otherwise masked constraints will likely become controlling.

The sub-hourly model (5 minute time step) will perform a constrained optimization for both asset commitment and asset dispatch against a sub-hourly desired load that utilizes both near term (next few time steps ahead) and intermediate term (out to the largest minimum down time of committed assets) load forecasts. The assets considered include generation (dispatchable and non-dispatchable), demand response, and energy storage. Each asset will have two primary states: available or unavailable. Each unavailable state may have sub-states—for example, scheduled versus unscheduled outage. Each asset will also have a series of constraints or attributes:

- Maximum output (or curtailment)
- Minimum output (or curtailment)
- Ramp up constraint
- Ramp down constraint
- Minimum run time
- Minimum down time
- Maximum run time curve as a function of operating state (energy storage, demand response, emission limits, fuel availability, etc.)
- Time between failures
- Time to restore
- Planned outages
- Startup cost
- Variable cost curve as a function of MW (input/output curve, heat rate curve, O&M, fuel forecast)
- Fixed costs (for annual cost calculations)

There are also system constraints that must be met. These include:

- Spinning reserve requirements (incorporating energy storage and demand response options)
- Grid stability requirements, including must-run units (constraints will be rules-based, as power flow modeling is not envisioned as feasible within the project time constraints)
- Policy constraints (power quality, reliability targets, risk tolerance)

The sub-hourly model will change the state of each asset to optimize the economics within the bounds of the model constraints. Accounting routines will keep track of asset performance ($, MWh, number of starts) and system performance (unserved load, curtailed generation, $, MWh). We envision sensitivities where selected constraints are relaxed and where the load forecast is modified. This will help test the robustness of the plan.

The modeling approach defined above is ideally suited to evaluating, comparing, and contrasting differing strategies regarding the mix of fossil generation, utility renewables versus energy storage, distributed generation versus energy storage, and demand response options. Based on the supply options provided, the model will determine the low-cost means for meeting the required load and base constraints. These constraints can be modified to evaluate other policy considerations (such as greater renewable penetration) that may move the solution away from optimal.

D. System Security Standards

The Hawaiian Electric Company contracted with Electric Power Systems and its two senior project engineers, David A Meyer and David W Burlingame, to conduct a system security and stability study and analysis of the Hawaiian Electric power grid.

Herewith is a discussion of the study and its resultant effects for system security on the Hawaiian Electric power grid.

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Tables

INTRODUCTION

EPS completed a study to determine the security constraints required to maintain system reliability in accordance with the draft Transmission Planning criteria TPL-001 and generation Planning criteria BAL-502. Due to the proliferation of distributed PV and its existing characteristics, the system is not currently in compliance with the planning standards. This study analyzed the future changes in generation resources to determine the security constraints required using the existing system topology required to meet the reliability standards. The study's scope is to identify what resources or mitigation measures can be undertaken to maximize the use of renewables and meet the transmission and generation planning criteria.

The initial year of the study is 2015 and proceeds through a series of forecasted load and resources changes through the year 2030. In the years 2015–16 a large amount of distributed PV growth is forecast and in year 2016 there is 283 MW of station class PV expected to be online. Years 2016–2030 forecast less growth in distributed PV but major additions and retirements to the Hawaiian Electric generation fleet and the installation of energy storage expected in 2017.

The years 2015–16 are expected to require mitigating efforts such as unit constraints, curtailment and relaxation of some reliability criteria during certain conditions due to the lack of ability to bring additional energy resources online.

This study outlines the types of mitigation and operating constraints for the years 2015–16 and the resource additions required to meet the security constraints for the system in the years 2017–2030.

It is important to note that this is a planning study and not an operating study. As such, the boundary conditions which the system can be operated will be identified, even though actual operations may not utilize the dispatch or unit commitment conditions identified as the boundary conditions. The boundary conditions were identified by configuring the generation dispatches to stress the system to determine the stability and contingency reserve requirements for the system.

METHODOLOGY

The reduction in system inertia and system response due to displacement of conventional generation units by variable energy will result in a less robust power system. This can potentially increase the amount of stages of the Under Frequency Load Shed (UFLS) system that will activate for unit trips and result in lower critical clearing times for all transmission and subtransmission faults.

System Improvement Assumptions

This section lists the system improvements assumed for the different study years.

2015–2016 Cases

The distributed PV installed prior to 2015 is assumed to be retrofitted to provide ride-through characteristics outlined in the proposed Rule 14h changes. No other system improvements in generation or transmission resources are anticipated.

2017+ Cases

The analysis incorporates a 60 MW Battery Energy Storage System (BESS) assumed to be installed in 2017. The Energy Storage System (ESS) is assumed to have both droop response and auto-schedule response capabilities for control action.

Initial analysis determined that voltage support would be required for the Hawaiian Electric system in order to maintain voltage due to the addition of renewable energy sources. The analysis indicated an initial size of ± 80 MVAR SVC would be adequate to resolve voltage problems on the Hawaiian Electric transmission system.

The critical fault clearing times on the Hawaiian Electric system are below 12 cycles. It is assumed that dual primary, communications assisted relaying is installed on all Hawaiian Electric 138 kV and 46 kV circuits.

The extreme variation in feeder loading during daytime and nighttime conditions require and adaptive relaying scheme for the under frequency load shedding system. This system is assumed to be in service in 2017. Due to the requirements of the under frequency loadshed scheme, SCADA control of all distribution circuits will be required for the new system. It is assumed that SCADA control will be establish to all substations by 2017.

Control of all station class PV is assumed in 2017. Control would allow station PV to be curtailed and used for regulation of other variable resources. Control of all DG PV is assumed in 2017. Control of DG would allow the curtailed PV to provide 10-minute reserves to replace regulation reserves used to counter ramping of the variable generation.

Station class PV is assumed to have both droop response and auto-scheduling response to allow its use as contingency reserves.

PV Assumptions

The amount of PV that would utilize legacy trip settings was analyzed at 40 and 60 MW of the total DG for the 2015–2016 cases. This dual analysis was completed to help quantify the impact of converting some of the existing legacy PV to extended ride through settings.

It was assumed that only 40 MW of the total PV installed would utilize legacy trip settings for voltage and frequency for the 2017+ cases. The remaining PV was assumed to have extended ride through characteristics providing the ability for the PV to remain online during system contingencies. The settings used for the legacy and extended PV capability are shown below in Table D-1.

PV Type	Protection Type		Settings 1		Settings 2	
			Set Point (Hz or	Time (sec)	Set Point (Hz or	Time (sec)
Legacy	Voltage	Over	1.10	0.99	1.2	0.157
		Under	0.88	1.99	0.5	0.157
	Frequency	Over	60.5	0.157	-	-
		Under	59.3	0.157	-	-
Extended	Voltage	Over	1.10	0.99	1.2	0.157
		Under	0.88	1.99	0.5	0.49
	Frequency	Over	63	19.99	-	-
		Under	57	19.99	-	-

Table D-1. PV Settings

It is important to note that the legacy PV has an under frequency trip setting of 59.3 Hz and a relay time of 0.157 seconds. Based on these settings, an under frequency event is likely to result in tripping of the legacy PV, further depressing system frequency following its tripping. The legacy PV trips on over frequency at 60.5 Hz also in 0.157 seconds. The loss of legacy PV following a transmission fault will decrease system security. The extended PV settings have an under frequency set point of 57 Hz and a relay time of 20 seconds, resulting in minimal PV tripping during under frequency events.

Criteria

The criteria for the system security studies are based on Hawaiian Electric's adopted planning document TPL-001. The planning document outlines the transmission and generation contingencies and the acceptable performance of the system.

The generation planning criteria BAL-502 also contains required characteristics of future energy resources that were used in the system studies.

The overriding criteria used for the analysis was that the system should not activate more than the Stage 1 of the UFLS system during single unit outages or a loss of a wind generation facility or PV source. Stage 1 currently results in the loss of customers that is acceptable to the planning criteria in TPL-001. The settings used for the existing UFLS system are shown below in Table D-2.

UFLS Stage	Set Point (Hz)	Relay Time (Sec)	Breaker Time (sec)
Stage 1	58.9	0.033	0.083
Stage 2	58.7	0.033	0.083
Stage 3	58.4	0.033	0.083
Stage 4	58.1	0.033	0.083
Stage 5	57.8	0.033	0.083
Kicker 1	59	5.030	0.083
Kicker 2	59	10.033	0.083

Table D-2. UFLS Settings

During analysis, if the simulation results in a frequency response below 58.7 Hz, outage was reduced and or changes to the UFLS settings were completed to try and meet the criteria. These changes to the UFLS settings include transfer tripping stages 1 and/or stages 2 in order to try and keep the frequency from dropping and tripping any additional stages.

Contingency Reserves Analysis

The replacement of traditional generation with variable generation will require additional contingency reserves for the 2017+ cases. Contingency reserves in the form of additional ESS (or another type of very fast-acting frequency-responsive resource that has the same capabilities as fast energy storage, such as utilizing auto-scheduling of curtailed station class PV) were added to the system provide system stability and meet the performance requirements of TPL-001. The use of auto-scheduling of the curtailed PV and of any ESS would occur 6 cycles after a unit outage.

During analysis, if the simulation results in a frequency response below 58.7 Hz, the contingency reserves (curtailed PV or ESS) were increased in 20 MW increments until the frequency stayed above limits during the simulation.

Contingencies

Contingencies including major 138 kV lines with 7 cycle clearing times and selected transmission lines with zone 2 clearing (5 cycle near clearing and 24 cycle far clearing times, only for 2015 cases)) were used to determine system stability. The outage of the largest thermal unit (typically AES at 200 MW and 100 MW) or wind generation facility was used to identify the ability to meet the standards set forth in TPL-001. A list of contingencies used for the study is shown below in Table D-3.

Dist #	From Bus		To Bus		Branch ID	Clearing Time (Cycles)	
	#	Name	#	Name		Near	Far
d0	100	ARCHER	130	IWILEI	"1"	7	7
d1	100	ARCHER	180	SCHOOL	"1"	7	7
d2	100	ARCHER	240	KEWALO	"1"	7	7
d3	110	CEIP	141	KAHE CD	"1"	7	7
d4	110	CEIP	330	AES	"1"	7	7
d5	110	CEIP	340	EWA NUI	"1"	7	7
d6	120	HALAWA	130	IWILEI	"1"	7	7
d7	120	HALAWA	140	KAHE AB	"1"	7	7
d8	120	HALAWA	150	KOOLAU	"1"	7	7
d9	120	HALAWA	160	MAKALAPA	"1"	7	7
d10	120	HALAWA	180	SCHOOL	"1"	7	7
d11	130	IWILEI	180	SCHOOL	"1"	7	7
d12	130	IWILEI	220	AIRPORT	"1"	7	7
d13	140	KAHE AB	141	KAHE CD	"1"	7	7
d14	140	KAHE AB	190	WAHIAWA	"1"	7	7
d15	140	KAHE AB	200	WAIAU	"1"	7	7
d16	150	KOOLAU	170	PUKELE	"1"	7	7
d17	150	KOOLAU	200	WAIAU	"1"	7	7
d18	160	MAKALAPA	200	WAIAU	"1"	7	7
d19	160	MAKALAPA	220	AIRPORT	"1"	7	7
d20	190	WAHIAWA	200	WAIAU	"1"	7	7
d21	200	WAIAU	340	EWA NUI	"1"	7	7
d22	230	KAMOKU	240	KEWALO	"1"	7	7
d23	310	KALAE	330	AES	"1"	7	7
d24	310	KALAE	340	EWA NUI	"1"	7	7
d25	320	HRRP	330	AES	"1"	7	7
u0	1331	AES	-	-	-	-	
d26	140	KAHE AB	190	WAHIAWA	"1"	5	24
d27	140	KAHE AB	120	HAL1	"1"	5	24
d28	140	KAHE AB	120	HAL2	"2"	5	24
d29	200	WAIAU	190	WAHIAWA	"1"	5	24
d30	200	WAIAU	160	MAKALAPA	"1"	5	24
d31	120	HALAWA	160	MAKALAPA	"1"	5	24
d32	120	HALAWA	180	SCHOOL	"1"	5	24
d33	120	HALAWA	130	IWILEI	"1"	5	24

Table D-3. Contingencies

YEAR 2015 ANALYSIS

Power flow cases were created for the day minimum, day peak, evening peak, and night minimum load times. Specifics for each case are shown below in Table D-4. The DG-PV, station PV, and wind are the variable generation production (in MW). The thermal generation listed is the total MW from thermal generation dispatch. The regulation is the unloaded capacity. The combined load and losses are the demand that is to be served by the generation sources.

Values	2015 Load Cases			
	Day Minimum	Day Peak	Evening Peak	Night Minimum
DG PV	408	408	0	0
Station PV	10	10	0	0
Wind	99	99	99	99
Load	752	1151	1222	554
Losses	8	15	27	10
Thermal Generation	243	649	1150	465
Regulation	135	135	50	50

Table D-4. 2015 Case Specifics

2015: Generation Dispatches

Generation dispatches were created for each case, increasing AES output from a low value (80–100 MW) to the maximum possible output in 20 MW increments. Details of the generation dispatches for the daytime minimum cases are shown in Table D-5.

Unit	2015 Values		2015				
	Pmax	Pmin	Day Min				
Kahe 1	86	24					
Kahe 2	86	24					
Kahe 3	90	24	28				
Kahe 4	89	24	28	28	32	24	24
Kahe 5	142	65	72	80	90	80	65
Kahe 6	142	64					
Kalaeloa CT 1	86	31					
Kalaeloa CT 2	86	31					
Kalaeloa ST	41	11					
Waiau 7	83	24					
Waiau 8	86	24					
Waiau 3	47	24					
Waiau 4	46	24					
HRRP 1	46	35	35	35			
AES	201	67	80	100	120	140	160
Total Thermal			243	243	242	244	249
Wind			99	99	99	99	99
PV - DG			408	408	408	408	408
PV - Station			10	10	10	10	10
Total Renewable			517	517	517	517	517
Total Gen			760	760	759	761	766
Load			752	752	752	752	752
Losses (assumed)			8.1	8.1	8.1	8.1	8.1
Total Gen Needed			760.1	760.1	760.1	760.1	760.1
Reg UP Required			135	135	135	135	135
Reg Up Available			325	235	190	188	183
Reg Down Available			29	53	87	89	94

Table D-5. 2015 Day Minimum Generation Dispatch

Details for the day peak generation dispatches are shown below in Table D-6. Due to the possibility of generation dispatches being adjusted as to have more units online for system support, the day peak cases were run with two different dispatches, a minimum unit case, and a maximum unit case.

Unit	2015 Values		2015											
			Day Peak						Day Peak, max units					
	Pmax	Pmin												
Kahe 1	86	24	86	81	81	74	67	60	35	30	24	24	24	24
Kahe 2	86	24	86	81	81	74	67	60	35	35	24	24	24	24
Kahe 3	90	24	90	81	81	74	67	60	35	35	32	24	24	24
Kahe 4	89	24	89	89	89	89	89	89	35	35	35	24	24	24
Kahe 5	142	65	110	110	90	90	90	90	100	100	100	100	92	85
Kahe 6	142	64							100	100	100	100	92	85
Kalaeloa CT 1	86	31	31	31	31	31	31	31	31	31	31	31	31	31
Kalaeloa CT 2	86	31							31	31	31	31	31	31
Kalaeloa ST	41	11	11	11	11	11	11	11	11	11	11	11	11	11
Waiau 7	83	24							35	24	24	24	24	24
Waiau 8	86	24							30	24	24	24	24	24
Waiau 3	47	24							24	24	24	24	24	24
Waiau 4	46	24												
HRRP 1	46	35	46	46	46	46	46	46	46	46	46	46	46	35
AES	201	67	100	120	140	160	180	200	100	120	140	160	180	200
Total Thermal			649	650	650	649	648	647	648	646	646	647	651	646
Wind			99	99	99	99	99	99	99	99	99	99	99	99
PV - DG			408	408	408	408	408	408	408	408	408	408	408	408
PV - Station			10	10	10	10	10	10	10	10	10	10	10	10
Total Renewable			517	517	517	517	517	517	517	517	517	517	517	517
Total Gen			1166	1167	1167	1166	1165	1164	1165	1163	1163	1164	1168	1163
Load			1151	1151	1151	1151	1151	1151	1151	1151	1151	1151	1151	1151
Losses (assumed)			15	15	15	15	15	15	13.7	13.7	13.7	13.7	13.7	13.7
Total Gen Needed			1166	1166	1166	1166	1166	1166	1165	1165	1165	1165	1165	1165
Reg UP Required			135	135	135	135	135	135	135	135	135	135	135	135
Reg Up Available			218	217	217	218	219	220	664	666	666	665	661	666
Reg Down Available			345	346	346	345	344	343	178	176	176	177	181	176

Table D-6. 2015 Day Peak Generation Dispatches

Details of the generation dispatches for the evening peak cases are shown in Table D-7.

Unit	2015 Values		2015					
	Pmax	Pmin	Evening Peak					
Kahe 1	86	24	86	86	86	86	86	86
Kahe 2	86	24	86	86	86	86	86	86
Kahe 3	90	24	90	90	90	90	90	90
Kahe 4	89	24	86	86	86	86	86	86
Kahe 5	142	65	90	102	117	107	97	87
Kahe 6	142	64	90	102	117	107	97	87
Kalaeloa CT 1	86	31	86	86	86	86	86	86
Kalaeloa CT 2	86	31	86	86	86	86	86	86
Kalaeloa ST	41	11	41	41	41	41	41	41
Waiau 7	83	24	83	83	83	83	83	83
Waiau 8	86	24	86	86	86	86	86	86
Waiau 3	47	24	47	47				
Waiau 4	46	24	47					
HRRP 1	46	35	46	46	46	46	46	46
AES	201	67	100	120	140	160	180	200
Total Thermal			1150	1147	1150	1150	1150	1150
Wind			99	99	99	99	99	99
PV - DG			0	0	0	0	0	0
PV - Station			0	0	0	0	0	0
Total Renewable			99	99	99	99	99	99
Total Gen			1249	1246	1249	1249	1249	1249
Load			1222	1222	1222	1222	1222	1222
Losses (assumed)			27	27	27	27	27	27
Total Gen Needed			1249	1249	1249	1249	1249	1249
Reg UP Required			50	50	50	50	50	50
Reg Up Available			208	165	115	115	115	115
Reg Down Available			656	677	704	704	704	704

Table D-7. 2015 Evening Peak Generation Dispatches

Details for the night minimum generation dispatches are shown below in Table D-8. Due to the possibility of generation dispatches being adjusted as to have more units online for system support, the night minimum cases were run with two different dispatches, a minimum unit case, and a maximum unit case.

Unit	2015 Values		2015												
			Night Minimum						Night Minimum, max units					
	Pmax	Pmin												
Kahe 1	86	24							24	24				
Kahe 2	86	24	40	24					24	24	24			
Kahe 3	90	24	90	90	90	80	70	60	24	24	24	24		
Kahe 4	89	24	89	89	89	80	70	60	24	24	24	24	24	24
Kahe 5	142	65	100	96	100	100	100	100	65	70	72	75	75	67
Kahe 6	142	64							64	70	72	75	75	67
Kalaeloa CT 1	86	31							31	31	31	31	31	31
Kalaeloa CT 2	86	31							31	31	31	31	31	31
Kalaeloa ST	41	11							11	11	11	11	11	11
Waiau 7	83	24							32					
Waiau 8	86	24												
Waiau 3	47	24												
Waiau 4	46	24												
HRRP 1	46	35	46	46	46	46	46	46	35	35	35	35	35	35
AES	201	67	100	120	140	160	180	200	100	120	140	160	180	200
Total Thermal			465	465	465	466	466	466	465	464	464	466	462	466
Wind			99	99	99	99	99	99	99	99	99	99	99	99
PV - DG			0	0	0	0	0	0	0	0	0	0	0	0
PV - Station			0	0	0	0	0	0	0	0	0	0	0	0
Total Renewable			99	99	99	99	99	99	99	99	99	99	99	99
Total Gen			564	564	564	565	565	565	564	563	563	565	561	565
Load			554	554	554	554	554	554	554	554	554	554	554	554
Losses (assumed)			10	10	10	10	10	10	10	10	10	10	10	10
Total Gen Needed			564	564	564	564	564	564	564	564	564	564	564	564
Reg UP Required			50	50	50	50	50	50	50	50	50	50	50	50
Reg Up Available			189	189	103	102	102	102	713	631	545	457	371	367
Reg Down Available			227	227	251	252	252	252	43	65	89	115	135	139

Table D-8. 2015 Night Minimum Generation Dispatches

2015: Results: Analysis

The results for the 2015 cases are organized by load case below. To aid in analyzing the results, a coloring scheme was added to the tables to easily show the minimum frequencies found during the simulation. The coloring scheme is shown in Table D-9 below.

Stage	1	58.9
Stage	2	58.7
Stage	3	58.4
Stage	4	58.1
Stage	5	57.8

Table D-9. 2015 Results Key: UFLS Stages

2015 Results: Day Minimum

The stability Zone 1 clearing results for the day minimum cases are shown below in Table D-10. The results show that 60 MW of legacy PV on the system result in Stage 1 UFLS activation for some Zone 1 transmission line contingencies, due to a loss of the PV during the transient system response. Reducing the amount of legacy PV to 40 MW eliminates the UFLS activation for transmission contingencies. Note that contingency d25, HRRP2AES, is a transmission line fault and trip that results in a loss of generation at HRRP to the rest of the Hawaiian Electric system. Note that HRRP is turned off when AES output is increased to 120 MW and above, thereby mitigating the severity of this disturbance.

Case	# Legacy (MW)	AES Outage	"ARCH2IWIL"	"ARCH2SCHO"	"ARCH2KEWA"	"CEIP2KAHE"	"CEIP2AES"	"CEIP2EWA"	"HALA2IWIL"	"HALA2KAHE"	"HALA2KOOL"	"HALA2MAKA"	"HALA2SCHO"	"IWIL2SCHO"	"IWIL2AIRP"	"KAHE2KAHE"	"KAHE2WAHI"	"KAHE2WAIA"	"KOOL2PUKE"	"KOOL2WAIA"	"MAKA2WAIA"	"MAKA2AIRP"	"WAHI2WAIA"	"WAIA2EWA"	"KAMO2KEWA"	"KALA2AES"	"KALA2EWA"	"HRRP2AES"
			d0	d1	d2	d3	d4	d5	d6	d7	d8	d9	d10	d11	d12	d13	d14	d15	d16	d17	d18	d19	d20	d21	d22	d23	d24	d25
day min	40	80	60.0	60.0	60.0	59.9	59.9	59.9	60.0	60.0	59.9	60.0	60.0	60.0	60.0	60.0	59.9	59.9	60.0	60.0	59.9	60.0	59.9	59.9	60.0	59.9	59.9	58.9
		100	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.8	59.9	60.0	59.9	59.9	58.7
		120	59.9	59.9	59.9	59.0	59.0	59.0	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.0	59.0	59.0	59.9	59.9	59.9	59.9	59.8	59.9	59.3	59.5	59.0	59.0
		140	59.9	59.9	59.9	59.0	59.0	59.0	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.1	59.0	59.0	59.9	59.9	59.9	59.9	59.8	59.9	59.3	59.0	59.0	59.9
		160	59.9	59.9	59.9	59.0	59.0	59.0	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.1	59.0	59.0	59.9	59.9	59.9	59.9	59.9	59.9	59.4	59.0	59.0	59.9
	60	80	60.0	60.0	60.0	59.9	59.9	59.9	60.0	60.0	59.9	60.0	60.0	60.0	60.0	60.0	59.9	59.9	60.0	60.0	59.9	60.0	59.9	59.9	60.0	59.9	59.9	58.8
		100	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.8	59.9	60.0	59.9	59.9	58.6
		120	59.9	59.9	59.9	58.8	58.8	58.8	59.9	59.9	59.9	59.9	59.9	59.9	59.9	58.8	58.8	58.8	59.9	59.9	59.9	59.9	59.8	59.9	58.9	59.3	58.8	58.8
		140	59.9	59.9	59.9	58.8	58.8	58.8	59.9	59.9	59.9	59.9	59.9	59.9	59.9	58.8	58.8	58.8	59.9	59.9	59.9	59.9	59.8	59.9	58.9	58.8	58.8	59.9
		160	59.9	59.9	59.9	58.8	58.8	58.8	59.9	59.9	59.9	59.9	59.9	59.9	59.9	58.8	58.8	58.8	59.9	59.9	59.9	59.9	59.9	59.9	58.9	58.8	58.8	59.9

Table D-10. 2015 Stability Results: Day Minimum; Zone 1 Clearing

The stability AES trip and Zone 2 clearing results for the day minimum cases are shown below in Table D-11. Zone 2 clearing for transmission faults result in UFLS activation to Stage 1 and Stage 2 for many lines, with increased UFLS activation occurring as AES output is increased. Reducing the amount of legacy PV from 60 MW to 40 MW reduces the severity of these contingencies, resulting in a reduction in UFLS activation for some cases and an improved system response. Note that a fault and trip of the Waiau – Makalapa and Halawa – School lines with AES at 160 MW output results in all 5 Stages of UFLS activating for legacy PV amounts of 60 MW and 40 MW.

Case	# Legacy (MW)	AES Outage	"KAHE-WAHI"	"KAHE-HAL1"	"KAHE-HAL2"	"WAIA-WAHI"	"WAIA-MAKA"	"HALA-MAKA"	"HALA-SCHO"	"HALA-IWIL"
			d26	d27	d28	d29	d30	d31	d32	d33
day min	40	80	59.5	59.2	59.2	59.8	59.2	59.2	59.2	59.2
		100	59.0	59.0	59.0	58.9	58.9	58.9	58.9	58.9
		120	58.9	58.9	58.9	58.9	58.9	58.9	58.9	58.9
		140	58.9	58.9	58.9	58.9	58.8	58.8	58.9	58.9
		160	58.9	58.9	58.9	58.9	54.9	55.1	58.8	58.9
	60	80	59.4	58.9	58.9	59.7	58.9	58.9	58.9	58.9
		100	58.8	58.8	58.8	58.7	58.7	58.7	58.7	58.8
		120	58.7	58.7	58.7	58.7	58.7	58.7	58.7	58.7
		140	58.8	58.7	58.7	58.7	58.6	58.6	58.7	58.7
		160	58.8	58.7	58.7	58.7	55.0	55.1	58.6	58.6
				Zone 2 Clearing						

Table D-11. 2015 Stability Results: Day Minimum; Zone 2 Clearing

The results for a trip of AES for the day minimum cases are shown below in Table D-12. The results show that a trip of AES at 80 MW results in UFLS activation to Stage 4 with 60 MW of legacy PV. Further increases in AES output result in additional stages of UFLS activation. Decreasing the amount of legacy PV from 60 MW to 40 MW results in a slight improvement in system response. Utilizing a transfer-trip scheme for UFLS Stages 1 and 2 has a minor impact on the results.

Load	Legacy PV	AES Trip (MW)	Transfer Trip UFLS		
			None	Stage 1	Stage 1 and 2
day min	40	80	58.3	58.3	58.4
		100	57.9	58.0	58.0
		120	57.7	57.7	57.7
		140	57.1	57.1	57.1
		160	56.5	56.5	56.6
	60	80	58.1	58.1	58.3
		100	57.8	57.8	57.8
		120	57.3	57.4	57.4
		140	56.6	56.6	56.6
		160	55.9	55.9	56.0

Table D-12. 2015 Results: Day Minimum; AES Trip

2015 Results: Day Peak

The stability Zone 1 clearing results for the day peak cases are shown below in Table D-13. The results show that using 60 MW or 40 MW of legacy PV on the system does not result in any UFLS activation for Zone 1 transmission line contingencies. Note that contingency d25, HRRP2AES, is a transmission line fault and trip that results in a loss of generation at HRRP to the rest of the Hawaiian Electric system, resulting in Stage 1 UFLS activation for this contingency.

Case	# Legacy (MW)	AES Outage	"ARCH2IWIL"	"ARCH2SCHO"	"ARCH2KEWA"	"CEIP2KAHE"	"CEIP2AES"	"CEIP2EWA"	"HALA2IWIL"	"HALA2KAHE"	"HALA2KOOL"	"HALA2MAKA"	"HALA2SCHO"	"IWIL2SCHO"	"IWIL2AIRP"	"KAHE2KAHE"	"KAHE2WAHI"	"KAHE2WAIA"	"KOOL2PUKE"	"KOOL2WAIA"	"MAKA2WAIA"	"MAKA2AIRP"	"WAHI2WAIA"	"WAIA2EWA"	"KAMO2KEWA"	"KALA2AES"	"KALA2EWA"	"HRRP2AES"
			d0	d1	d2	d3	d4	d5	d6	d7	d8	d9	d10	d11	d12	d13	d14	d15	d16	d17	d18	d19	d20	d21	d22	d23	d24	d25
day peak	40	100	59.9	59.9	59.9	59.4	59.4	59.4	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.4	59.4	59.4	59.9	59.9	59.9	59.9	59.9	59.5	60.0	59.4	59.4	58.9
		120	59.9	59.9	59.9	59.5	59.5	59.5	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.5	59.5	59.5	59.9	59.9	59.9	59.9	59.9	59.5	60.0	59.5	59.5	59.1
		140	59.9	59.9	59.9	59.5	59.5	59.5	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.5	59.5	59.5	59.9	59.9	59.9	59.9	59.9	59.5	60.0	59.5	59.5	59.3
		160	59.9	59.9	59.9	59.3	59.3	59.3	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.3	59.3	59.3	59.9	59.9	59.9	59.9	59.9	59.4	60.0	59.3	59.3	58.9
		180	59.9	59.9	59.9	59.5	59.5	59.5	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.5	59.5	59.5	59.9	59.9	59.9	59.9	59.9	59.6	60.0	59.5	59.5	59.3
		200	59.9	59.9	59.9	59.4	59.4	59.4	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.4	59.4	59.4	59.9	59.9	59.9	59.9	59.9	59.7	60.0	59.4	59.4	58.9
	60	100	59.9	59.9	59.9	59.2	59.2	59.2	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.2	59.2	59.2	59.9	59.9	59.9	59.8	59.9	59.2	60.0	59.2	59.2	58.8
		120	59.9	59.9	59.9	59.2	59.2	59.3	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.2	59.2	59.2	59.9	59.9	59.9	59.9	59.9	59.3	60.0	59.2	59.3	58.9
		140	59.9	59.9	59.9	59.2	59.2	59.3	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.2	59.2	59.2	59.9	59.9	59.9	59.9	59.9	59.4	60.0	59.3	59.3	58.9
		160	59.9	59.9	59.9	59.3	59.3	59.3	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.3	59.3	59.3	59.9	59.9	59.9	59.9	59.9	59.4	60.0	59.3	59.3	58.9
		180	59.9	59.9	59.9	59.2	59.3	59.3	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.2	59.2	59.3	59.9	59.9	59.9	59.9	59.9	59.5	60.0	59.3	59.3	58.9
		200	59.9	59.9	59.9	59.2	59.2	59.2	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.2	59.2	59.2	59.9	59.9	59.9	59.9	59.9	59.7	60.0	59.2	59.2	58.9

Table D-13. 2015 Stability Results: Day Peak; Zone 1 Clearing

The stability Zone 2 clearing results for the day peak cases are shown below in Table D-14. Zone 2 clearing for transmission faults result in UFLS activation to Stage 1 and Stage 2 for many lines, with increased UFLS activation occurring as AES output is increased. Reducing the amount of legacy PV from 60 MW to 40 MW reduces the severity of these contingencies, resulting in a reduction in UFLS activation for some cases and an improved system response. Note that a fault and trip of the Waiau–Makalapa and Halawa–School lines with AES at 180–200 MW output results in Stage 1 of UFLS activating for legacy PV amounts of 60 MW. The UFLS activation is eliminated when the legacy PV amount is reduced to 40 MW.

Case	# Legacy (MW)	AES Outage	"KAHE-WAHI" d26	"KAHE-HAL1" d27	"KAHE-HAL2" d28	"WAIA-WAHI" d29	"WAIA-MAKA" d30	"HALA-MAKA" d31	"HALA-SCHO" d32	"HALA-IWIL" d33
day peak	40	100	59.4	59.4	59.4	59.3	59.2	59.2	59.3	59.3
		120	59.4	59.4	59.4	59.4	59.2	59.2	59.3	59.3
		140	59.4	59.4	59.4	59.4	59.2	59.2	59.3	59.3
		160	59.2	59.2	59.2	59.2	58.9	58.9	59.1	59.1
		180	59.4	59.4	59.4	59.4	59.2	59.2	59.3	59.3
		200	59.3	59.3	59.3	59.3	59.1	59.1	59.2	59.2
	60	100	59.1	59.1	59.1	59.1	58.9	58.9	59.0	59.0
		120	59.2	59.1	59.1	59.2	58.9	59.0	59.0	59.0
		140	59.2	59.1	59.1	59.2	58.9	58.9	59.0	59.0
		160	59.2	59.2	59.2	59.2	58.9	58.9	59.1	59.1
		180	59.2	59.1	59.2	59.2	58.9	58.9	59.0	59.0
		200	59.1	59.1	59.1	59.1	58.9	58.9	59.0	59.0
				Zone 2 Clearing						

Table D-14. 2015 Stability Results: Day Peak; Zone 2 Clearing

The results for a trip of AES for the day peak and day peak maximum unit dispatch cases are shown below in Table D-15. The results show that for the day peak dispatch, a trip of AES at 100 MW results in UFLS activation to Stage 2 with 60 MW of legacy PV. Further increases in AES output result in a maximum UFLS activation of Stage 3. Decreasing the amount of legacy PV from 60 MW to 40 MW results in a slight improvement in system response.

The day peak maximum unit dispatch results show that a trip of AES at 100 MW results in UFLS activation to Stage 1 with 60 MW of legacy PV. Further increases in AES output result in a maximum UFLS activation of Stage 2. Decreasing the amount of legacy PV from 60 MW to 40 MW results in a slight improvement in system response. Utilizing a transfer-trip scheme for UFLS stages 1 and 2 has a minor impact on the results, allowing for increases of AES output by 20 MW without increasing UFLS activation for some cases.

Load	Legacy PV	AES Trip (MW)	Transfer Trip UFLS		
			None	Stage 1	Stage 1 and 2
day peak	40	100	58.6	58.7	59.8
		120	58.6	58.6	59.6
		140	58.4	58.4	58.5
		160	58.3	58.3	58.3
		180	58.3	58.3	58.3
		200	58.2	58.2	58.3
	60	100	58.5	58.6	59.8
		120	58.4	58.4	59.6
		140	58.3	58.4	58.4
		160	58.3	58.3	58.3
		180	58.2	58.2	58.3
		200	58.1	58.1	58.1
day peak max units	40	100	58.9	59.6	59.9
		120	58.9	59.4	59.7
		140	58.8	59.0	59.5
		160	58.7	58.8	59.4
		180	58.6	58.7	58.9
		200	58.5	58.6	58.7
	60	100	58.9	59.6	59.9
		120	58.8	59.4	59.7
		140	58.7	58.8	59.5
		160	58.6	58.7	59.4
		180	58.5	58.6	58.8
		200	58.4	58.5	58.6

Table D-15. 2015 Results: Day Peak

2015 Results: Evening Peak

The results for a trip of AES for the evening peak cases are shown below in Table D-16. The results show that a trip of AES at 100 MW results in no UFLS activation. Further increases in AES output result in additional stages of UFLS activation up to Stage 2. Utilizing a transfer-trip scheme for UFLS Stage 1 has a minor impact on the results, allowing for only 1 stage of UFLS activated for AES at 180 MW output, instead of 2 stages.

Load	AES Trip (MW)	Transfer Trip UFLS		
		None	Stage 1	Stage 1 and 2
Evening Peak	100	59.1	59.8	59.9
	120	58.9	59.5	59.9
	140	58.9	59.3	59.8
	160	58.8	59.0	59.6
	180	58.7	58.7	59.4
	200	58.7	58.7	59.2

Table D-16. 2015 Results: Evening Peak

2015 Results: Night Minimum

The results for a trip of AES for the night minimum cases are shown below in Table D-17. The results show that a trip of AES at 100 MW results in Stage 2 UFLS activation. Further increases in AES output result in additional stages of UFLS activation up to Stage 4. Utilizing a transfer-trip scheme for UFLS stages 1 and 2 has a minor impact on the results.

The night minimum maximum units dispatch results show that a trip of AES at 100 MW results in no UFLS activation. Further increases in AES output result in additional stages of UFLS activation, up to Stage 4. Utilizing a transfer-trip scheme for UFLS stages 1 and 2 has a minor impact on the results.

Load	AES Trip (MW)	Transfer Trip UFLS		
		None	Stage 1	Stage 1 and 2
Night Minimum	100	58.6	58.7	59.0
	120	58.4	58.4	58.5
	140	58.1	58.2	58.2
	160	58.0	58.1	58.1
	180	58.0	58.0	58.0
	200	57.8	57.9	57.9
Night Minimum, Max Units	100	59.0	59.3	59.5
	120	58.8	58.9	59.2
	140	58.6	58.7	58.9
	160	58.4	58.4	58.4
	180	58.1	58.1	58.2
	200	58.0	58.1	58.1

Table D-17. 2015 Results: Night Minimum

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Power flow cases were created for the day minimum, day peak, evening peak, and night minimum load times. Specifics for each case are shown below in Table D-18.

Values	2016 Load Cases			
	Day Minimum	Day Peak	Evening Peak	Night Minimum
DG PV	450	450	0	0
Station PV	10	10	0	0
Wind	99	99	99	99
Load	752	1151	1222	554
Losses	8	15	27	10
Thermal Generation	201	607	1150	465
Regulation	143	143	50	50

Table D-18. 2016 Case Specifics

It was assumed for the 2016 cases that the Hawaiian Electric protection system was upgraded such that transmission line contingencies will no longer result in Zone 2 clearing.

2016 Generation Dispatches

Generation dispatches were created for each case, increasing AES output from a low value (80–100 MW) to the maximum possible output in 20 MW increments. Details of the generation dispatches for the daytime minimum cases are shown in Table D-19.

Unit	2016 Values		2016 Day Min				
	Pmax	Pmin					
Kahe 1	86	10	10	10	10		
Kahe 2	86	10	10	10	10	10	
Kahe 3	90	10	10	10	10	10	
Kahe 4	89	10	10	10	10	10	10
Kahe 5	142	25	45	25	40	30	30
Kahe 6	142	45					
Kalaeloa CT 1	86	31					
Kalaeloa CT 2	86	31					
Kalaeloa ST	41	11					
Waiau 7	83	10					
Waiau 8	86	10					
Waiau 3	47	24					
Waiau 4	46	24					
HRRP 1	46	35	35	35			
AES	201	67	80	100	120	140	160
Total Thermal			200	200	200	200	200
Wind			99	99	99	99	99
PV - DG			450	450	450	450	450
PV - Station			10	10	10	10	10
Total Renewable			559	559	559	559	559
Total Gen			759	759	759	759	759
Load			752	752	752	752	752
Losses (assumed)			8.1	8.1	8.1	8.1	8.1
Total Gen Needed			760	760	760	760	760
Reg UP Required			143	142	142	142	142
Reg Up Available			540	540	494	408	232
Reg Down Available			33	33	68	78	98

Table D-19. 2016 Day Minimum Generation Dispatch

Details for the day peak generation dispatches are shown below in Table D-20. Due to the possibility of generation dispatches being adjusted as to have more units online for system support, the day peak cases were run with two different dispatches, a minimum unit case, and a maximum unit case.

Unit	2016 Values		2016											
			Day Peak						Day Peak, max units					
	Pmax	Pmin												
Kahe 1	86	10	80	75	70	65	60	55	50	45	40	35	30	25
Kahe 2	86	10	80	75	70	65	60	55	50	45	40	35	30	25
Kahe 3	90	10	80	75	70	65	60	55	50	45	40	35	30	25
Kahe 4	89	10	85	80	75	70	65	60	50	45	40	35	30	25
Kahe 5	142	25	100	100	100	100	100	100	95	95	95	95	95	95
Kahe 6	142	45							95	95	95	95	95	95
Kalaeloa CT 1	86	31	31	31	31	31	31	31	31	31	31	31	31	31
Kalaeloa CT 2	86	31							31	31	31	31	31	31
Kalaeloa ST	41	11	11	11	11	11	11	11	11	11	11	11	11	11
Waiau 7	83	10												
Waiau 8	86	10												
Waiau 3	47	24												
Waiau 4	46	24												
HRRP 1	46	35	46	46	46	46	46	46	46	46	46	46	46	46
AES	201	67	100	120	140	160	180	200	100	120	140	160	180	200
Total Thermal			613	613	613	613	613	613	609	609	609	609	609	609
Wind			99	99	99	99	99	99	99	99	99	99	99	99
PV - DG			450	450	450	450	450	450	450	450	450	450	450	450
PV - Station			10	10	10	10	10	10	10	10	10	10	10	10
Total Renewable			559	559	559	559	559	559	559	559	559	559	559	559
Total Gen			1172	1172	1172	1172	1172	1172	1168	1168	1168	1168	1168	1168
Load			1157	1157	1157	1157	1157	1157	1151	1157	1157	1157	1157	1157
Losses (assumed)			15	15	15	15	15	15	13.7	13.7	13.7	13.7	13.7	13.7
Total Gen Needed			1172	1172	1172	1172	1172	1172	1165	1171	1171	1171	1171	1171
Reg UP Required			142	142	142	142	142	142	142	142	142	142	142	142
Reg Up Available			254	254	254	254	254	254	486	486	486	486	486	486
Reg Down Available			404	404	404	404	404	404	324	324	324	324	324	324

Table D-20. 2016 Day Peak Generation Dispatches

Details of the generation dispatches for the evening peak cases are shown in Table D-21.

Unit	2016 Values		2016					
			Evening Peak					
	Pmax	Pmin						
Kahe 1	86	10	86	86	86	86	86	86
Kahe 2	86	10	86	86	86	86	86	86
Kahe 3	90	10	90	90	90	90	90	90
Kahe 4	89	10	86	86	86	86	86	86
Kahe 5	142	25	90	102	117	107	97	87
Kahe 6	142	45	90	102	117	107	97	87
Kalaeloa CT 1	86	31	86	86	86	86	86	86
Kalaeloa CT 2	86	31	86	86	86	86	86	86
Kalaeloa ST	41	11	41	41	41	41	41	41
Waiau 7	83	10	83	83	83	83	83	83
Waiau 8	86	10	86	86	86	86	86	86
Waiau 3	47	24	47	47				
Waiau 4	46	24	47					
HRRP 1	46	35	46	46	46	46	46	46
AES	201	67	100	120	140	160	180	200
Total Thermal			1150	1147	1150	1150	1150	1150
Wind			99	99	99	99	99	99
PV - DG			0	0	0	0	0	0
PV - Station			0	0	0	0	0	0
Total Renewable			99	99	99	99	99	99
Total Gen			1249	1246	1249	1249	1249	1249
Load			1222	1222	1222	1222	1222	1222
Losses (assumed)			27	27	27	27	27	27
Total Gen Needed			1249	1249	1249	1249	1249	1249
Reg UP Required			50	50	50	50	50	50
Reg Up Available			208	165	115	115	115	115
Reg Down Available			798	818	845	845	845	845

Table D-21. 2016 Evening Peak Generation Dispatches

Details for the night minimum generation dispatches are shown below in Table D-22. Due to the possibility of generation dispatches being adjusted as to have more units online for system support, the night minimum cases were run with two different dispatches, a minimum unit case, and a maximum unit case.

Unit	2016 Values		2016											
	Pmax	Pmin	Night Minimum						Night Minimum, max units					
Kahe 1	86	10							24	10	10	10	10	10
Kahe 2	86	10	55	35	15	10	10	10	24	15	10	10	10	10
Kahe 3	90	10	90	90	90	85	65	45	24	24	10	10	10	10
Kahe 4	89	10	89	89	89	80	80	80	24	24	24	10	10	10
Kahe 5	142	25	100	100	100	100	100	100	90	90	90	85	75	65
Kahe 6	142	45							90	90	90	85	75	65
Kalaeloa CT 1	86	31							31	31	31	31	31	31
Kalaeloa CT 2	86	31							31	31	31	31	31	31
Kalaeloa ST	41	11							11	11	11	11	11	11
Waiau 7	83	10												
Waiau 8	86	10												
Waiau 3	47	24												
Waiau 4	46	24												
HRRP 1	46	35	46	46	46	46	46	46	35	35	35	35	35	35
AES	201	67	100	120	140	160	180	200	100	120	140	160	180	200
Total Thermal			480	480	480	481	481	481	484	481	482	478	478	478
Wind			99	99	99	99	99	99	99	99	99	99	99	99
PV - DG			0	0	0	0	0	0	0	0	0	0	0	0
PV - Station			0	0	0	0	0	0	0	0	0	0	0	0
Total Renewable			99	99	99	99	99	99	99	99	99	99	99	99
Total Gen			579	579	579	580	580	580	583	580	581	577	577	577
Load			570	570	570	570	570	570	570	570	570	570	570	570
Losses (assumed)			10	10	10	10	10	10	10	10	10	10	10	10
Total Gen Needed			580	580	580	580	580	580	580	580	580	580	580	580
Reg UP Required			50	50	50	50	50	50	50	50	50	50	50	50
Reg Up Available			174	174	174	173	173	173	611	614	613	617	617	617
Reg Down Available			323	323	323	324	324	324	199	196	197	193	193	193

Table D-22. 2016 Night Minimum Generation Dispatches

2016 Results

The results for the 2016 cases are organized by load case below. To aid in analyzing the results, a coloring scheme was added to the tables to easily show the minimum frequencies found during the simulation. The coloring scheme is shown in Table D-23 below.

Stage	1	58.9
Stage	2	58.7
Stage	3	58.4
Stage	4	58.1
Stage	5	57.8

Table D-23. 2016 Results: Key UFLS Stages

2016 Results: Day Minimum

The stability results for the day minimum cases are shown below in Table D-24. The results show that 60 MW and 40 MW of legacy PV on the system result no UFLS activation for transmission line contingencies. Reducing the amount of legacy PV to 40 MW eliminates the UFLS activation for transmission contingencies. Note that contingency d25, HRRP2AES, is a transmission line fault and trip that results in a loss of generation at HRRP to the rest of the Hawaiian Electric system. Note that HRRP is turned off when AES output is increased to 120 MW and above, thereby mitigating the severity of this disturbance.

Case	# Legacy (MW)	AES Outage	"ARCH2IWIL"	"ARCH2SCHO"	"ARCH2KEWA"	"CEIP2KAHE"	"CEIP2AES"	"CEIP2EWA"	"HALA2IWIL"	"HALA2KAHE"	"HALA2KOOL"	"HALA2MAKA"	"HALA2SCHO"	"IWIL2SCHO"	"IWIL2AIRP"	"KAHE2KAHE"	"KAHE2WAHI"	"KAHE2WAIA"	"KOOL2PUKE"	"KOOL2WAIA"	"MAKA2WAIA"	"MAKA2AIRP"	"WAHI2WAIA"	"WAIA2EWA"	"KAMO2KEWA"	"KALA2AES"	"KALA2EWA"	"HRRP2AES"
			d0	d1	d2	d3	d4	d5	d6	d7	d8	d9	d10	d11	d12	d13	d14	d15	d16	d17	d18	d19	d20	d21	d22	d23	d24	d25
day min	40	80	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.7	59.7	59.9	59.9	59.8	59.9	59.9	59.8	59.8	59.5
		100	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.7	59.7	59.9	59.9	59.8	59.9	59.9	59.8	59.8	59.5
		120	59.9	59.9	59.9	59.8	59.8	59.8	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	60.0	60.0	59.9	59.9	59.9	59.9	59.9	59.8	59.8	59.8
		140	59.9	59.9	59.9	59.8	59.8	59.8	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	60.0	60.0	59.9	59.9	59.9	59.9	60.0	59.8	59.8	59.8
		160	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	60.0	59.9	59.9	59.9
	60	80	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.5	59.5	59.9	59.9	59.8	59.9	59.9	59.8	59.8	59.5
		100	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.4	59.4	59.9	59.9	59.8	59.9	59.9	59.8	59.8	59.5
		120	59.9	59.9	59.9	59.8	59.8	59.8	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.7	59.7	59.9	59.9	59.9	59.9	59.9	59.8	59.8	59.8
		140	59.9	59.9	59.9	59.8	59.8	59.8	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.7	59.7	59.9	59.9	59.9	59.9	60.0	59.8	59.8	59.8
		160	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	60.0	59.9	59.9	59.9

Table D-24. 2016 Stability Results: Day Minimum

Note that no Zone 2 clearing analysis was completed for the 2016 cases as it is assumed that protection settings and equipment have been upgraded to eliminate the need for Zone 2 clearing for transmission line faults.

The results for a trip of AES for the day minimum cases are shown below in Table D-25. The results show that a trip of AES at 80 MW results in UFLS activation to Stage 3 with 60 MW of legacy PV. Further increases in AES output result in additional stages of UFLS activation. Decreasing the amount of legacy PV from 60 MW to 40 MW results in a slight improvement in system response, activating only to stage 2 for a trip of AES at 80 MW. Utilizing a transfer-trip scheme for UFLS Stages 1 and 2 has a minor impact on the results.

Season	Legacy PV	AES Trip (MW)	Transfer Trip UFLS		
			None	Stage 1	Stage 1 and 2
day min	40	80	58.5	58.5	59.3
		100	58.3	58.3	58.4
		120	58.0	58.0	58.1
		140	57.6	57.6	57.7
		160	55.1	55.1	55.2
	60	80	58.3	58.4	59.4
		100	58.1	58.2	58.2
		120	57.9	57.9	58.0
		140	57.3	57.4	57.5
		160	54.4	54.4	54.5

Table D-25. 2016 Results: Day Minimum

2016 Results: Day Peak

The stability results for the day peak cases are shown below in Table D-26. The results show that using 60 MW or 40 MW of legacy PV on the system does not result in any UFLS activation for contingencies. Note that contingency d25, HRRP2AES, is a transmission line fault and trip that results in a loss of generation at HRRP to the rest of the Hawaiian Electric system.

Case	# Legacy (MW)	AES Outage	"ARCH2IWIL"	"ARCH2SCHO"	"ARCH2KEWA"	"CEIP2KAHE"	"CEIP2AES"	"CEIP2EWA"	"HALA2IWIL"	"HALA2KAHE"	"HALA2KOOL"	"HALA2MAKA"	"HALA2SCHO"	"IWIL2SCHO"	"IWIL2AIRP"	"KAHE2KAHE"	"KAHE2WAHI"	"KAHE2WAIA"	"KOOL2PUKE"	"KOOL2WAIA"	"MAKA2WAIA"	"MAKA2AIRP"	"WAHI2WAIA"	"WAIA2EWA"	"KAMO2KEWA"	"KALA2AES"	"KALA2EWA"	"HRRP2AES"
			d0	d1	d2	d3	d4	d5	d6	d7	d8	d9	d10	d11	d12	d13	d14	d15	d16	d17	d18	d19	d20	d21	d22	d23	d24	d25
day peak	40	100	59.9	59.9	59.9	59.5	59.5	59.5	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.5	59.5	59.5	59.9	59.9	59.9	59.9	59.9	59.9	60.0	59.5	59.5	59.4
		120	59.9	59.9	59.9	59.5	59.5	59.5	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.5	59.5	59.5	59.9	59.9	59.9	59.9	59.9	59.9	60.0	59.5	59.5	59.4
		140	59.9	59.9	59.9	59.5	59.5	59.5	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.5	59.5	59.5	59.9	59.9	59.9	59.9	59.9	59.9	60.0	59.5	59.5	59.4
		160	59.9	59.9	59.9	59.3	59.3	59.3	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.3	59.3	59.3	59.9	59.9	59.9	59.9	59.9	59.9	60.0	59.3	59.4	59.4
		180	59.9	59.9	59.9	59.5	59.5	59.5	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.5	59.5	59.5	59.9	59.9	59.9	59.9	59.9	59.9	60.0	59.5	59.6	59.4
		200	59.9	59.9	59.9	59.5	59.5	59.5	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.5	59.5	59.5	59.9	59.9	59.9	59.9	59.9	59.9	60.0	59.5	59.5	59.4
	60	100	59.9	59.9	59.9	59.3	59.3	59.3	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.3	59.3	59.3	59.9	59.9	59.9	59.9	59.9	59.9	60.0	59.3	59.3	59.4
		120	59.9	59.9	59.9	59.3	59.3	59.3	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.3	59.3	59.3	59.9	59.9	59.9	59.9	59.9	59.9	60.0	59.3	59.4	59.4
		140	59.9	59.9	59.9	59.3	59.3	59.3	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.3	59.3	59.3	59.9	59.9	59.9	59.9	59.9	59.9	60.0	59.3	59.4	59.4
		160	59.9	59.9	59.9	59.3	59.3	59.3	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.3	59.3	59.3	59.9	59.9	59.9	59.9	59.9	59.9	60.0	59.3	59.4	59.4
		180	59.9	59.9	59.9	59.3	59.3	59.3	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.3	59.3	59.3	59.9	59.9	59.9	59.9	59.9	59.9	60.0	59.4	59.4	59.4
		200	59.9	59.9	59.9	59.3	59.3	59.3	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.3	59.3	59.3	59.9	59.9	59.9	59.9	59.9	59.9	60.0	59.3	59.4	59.4

Table D-26. 2016 Stability Results: Day Peak Zone 1 Clearing

Note that no Zone 2 clearing analysis was completed for the 2016 cases as it is assumed that protection settings and equipment have been upgraded to eliminate the need for Zone 2 clearing for transmission line faults.

The results for a trip of AES for the day peak and day peak maximum unit dispatch cases are shown below in Table D-27. The results show that for the day peak dispatch, a trip of

AES at 100 MW results in UFLS activation to Stage 2 with 60 MW of legacy PV. Further increases in AES output result in a maximum UFLS activation of Stage 4. Decreasing the amount of legacy PV from 60 MW to 40 MW results in a slight improvement in system response, mitigating the need for Stage 4 UFLS activation for an AES trip at 200 MW.

The day peak maximum unit dispatch results show that a trip of AES at 100 MW results in UFLS activation to Stage 1 with 60 MW of legacy PV. Further increases in AES output result in a maximum UFLS activation of Stage 3. Decreasing the amount of legacy PV from 60 MW to 40 MW results in a slight improvement in system response. Utilizing a transfer-trip scheme for UFLS stages 1 and 2 has a minor impact on the results, allowing for increases of AES output by 20 MW without increasing UFLS activation.

Load	Legacy PV	AES Trip (MW)	Transfer Trip UFLS		
			None	Stage 1	Stage 1 and 2
day peak	40	100	58.6	58.7	59.8
		120	58.6	58.6	59.6
		140	58.4	58.4	58.5
		160	58.3	58.3	58.3
		180	58.3	58.3	58.3
		200	58.2	58.2	58.3
	60	100	58.5	58.6	59.8
		120	58.4	58.4	59.6
		140	58.3	58.4	58.4
		160	58.3	58.3	58.3
		180	58.2	58.2	58.3
		200	58.1	58.1	58.1
day peak max units	40	100	58.9	59.6	59.9
		120	58.9	59.4	59.7
		140	58.8	59.0	59.5
		160	58.7	58.8	59.4
		180	58.6	58.7	58.9
		200	58.5	58.6	58.7
	60	100	58.9	59.6	59.9
		120	58.8	59.4	59.7
		140	58.7	58.8	59.5
		160	58.6	58.7	59.4
		180	58.5	58.6	58.8
		200	58.4	58.5	58.6

Table D-27. 2016 Results: Day Peak

2016 Results: Evening Peak

The results for a trip of AES for the evening peak cases are shown below in Table D-28. The results show that a trip of AES at 100 MW results in no UFLS activation. Further increases in AES output result in increased UFLS activation, to stage 2. Utilizing a transfer-trip scheme for UFLS stages 1 and 2 has a minor impact on the results, allowing for increases of AES output by 20 MW without increasing UFLS activation for some cases.

Load	AES Trip (MW)	Transfer Trip UFLS		
		None	Stage 1	Stage 1 and 2
Evening Peak	100	59.1	59.8	59.9
	120	58.9	59.5	59.9
	140	58.9	59.3	59.8
	160	58.8	59.0	59.6
	180	58.7	58.7	59.4
	200	58.7	58.7	59.2

Table D-28. 2016 Results: Evening Peak

2016 Results: Night Minimum

The results for a trip of AES for the night minimum cases are shown below in Table D-29. The results show that a trip of AES at 100 MW results in Stage 2 UFLS activation. Further increases in AES output result in additional stages of UFLS activation up to Stage 4. Utilizing a transfer-trip scheme for UFLS stages 1 and 2 has a minor impact on the results.

The night minimum maximum units dispatch results show that a trip of AES at 100 MW results in Stage 1 activation. Further increases in AES output result in additional stages of UFLS activation, up to Stage 3. Utilizing a transfer-trip scheme for UFLS stages 1 and 2 has a minor impact on the results, allowing for increases of AES output by 20 MW without increasing UFLS activation.

Load	AES Trip (MW)	Transfer Trip UFLS		
		None	Stage 1	Stage 1 and 2
Night Minimum	100	58.6	58.7	59.1
	120	58.4	58.4	58.5
	140	58.3	58.3	58.3
	160	58.2	58.2	58.3
	180	58.1	58.1	58.1
	200	58.0	58.0	58.0
	100	58.9	59.2	59.5
	120	58.8	59.0	59.3
	140	58.7	58.7	59.0
	160	58.5	58.6	58.7
	180	58.4	58.4	58.5
	200	58.3	58.4	58.4

Table D-29. 2016 Results: Night Minimum

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Power flow cases were created for the day minimum and night minimum load times. The day minimum cases assumed a load of 752 MW, with renewable generation resources consisting of 471 MW of distributed PV (40 MW legacy PV), 272 MW of station PV, and 123 MW of wind. The night minimum cases assumed a load of 586 MW, utilizing only the wind as available renewable energy sources. A 60 MW BESS is assumed to be installed in 2017 for all cases.

Contract limitations for AES and KLPP were assumed to be 90 MW/180 MW for AES and one simple cycle turbine for KLPP respectively. For each of the dispatch scenarios, the largest unit was operated at full load prior to the contingency event.

For the purposes of the system security study, a 60 MW BESS was assumed to be operational in 2017. The BESS is assumed to have both droop response and auto-schedule response capabilities to control action.

2017 Generation Dispatches

The dispatches utilized AES, HRRP #1 & #2, and Kalaeloa CT #1 generation resources. Generation sensitivities included utilizing additional generation from Kalaeloa CT #2, Kahe 5, and Kahe 6. The AES unit was dispatched at 100 MW and 200 MW, while the other units were all dispatched at their minimum outputs. Details of the generation dispatches for the daytime minimum cases are shown in Table D-30.

Unit	1 Kalaeloa Train		2 Kalaeloa Train		2 Kalaeloa Train. 1 kpp		2 Kalaeloa Train. 2kpp	
	AES		AES		AES		AES	
	200	100	200	100	200	100	200	100
Kalaeloa CT1	15	15	25	25	25	25	25	25
Kalaeloa CT2	0	0	25	25	25	25	25	25
Kahe 5	0	0	0	0	25	25	25	25
Kahe 6	0	0	0	0	0	0	45	45
HRRP 1	25	25	25	25	25	25	25	25
HRRP 2	10	10	10	10	10	10	10	10
AES	200	100	200	100	200	100	200	100
Total Thermal	250	150	285	185	310	210	355	255
Wind	123	123	123	123	123	123	123	123
PV - DG	471	471	471	471	471	471	471	471
PV - Station	272	272	272	272	272	272	272	272
Total Renewable	866	866	866	866	866	866	866	866
RE Curtailed	349	249	384	284	409	309	454	354
Total Renewable available	517	617	482	582	457	557	412	512
Load - day min	752	752	752	752	752	752	752	752
Losses (assumed)	15	15	15	15	15	15	15	15

Table D-30. Day Minimum Generation Dispatch

Details for the night minimum generation dispatches are shown below in Table D-31.

Unit	night minimum	
	AES	
	200	100
Kalaeloa CT1	86	86
Kalaeloa CT2	86	86
Kalaeloa ST	41	41
Kahe 5	0	100
Kahe 6	0	0
HRRP 1	46	46
HRRP 2	25	25
AES	200	100
Total Thermal	484	484
Wind	123	123
PV - DG	0	0
PV - Station	0	0
Total Renewable	123	123
Total Renewable available	123	123
Load - day min	586	586
Losses (assumed)	15	15

Table D-31. Night Minimum Generation Dispatch

2017 Results

The day minimum cases show that for a 200 MW trip of AES, utilizing the 60 MW BESS assumed for 2017 operation requires an additional 120–140 MW of contingency reserves. For a 100 MW trip of AES, an additional 20–40 MW of contingency reserves is needed. Detailed results for the day minimum cases are shown below in Table D-32.

Station PV		AES	1 Kalaeloa CT			2 Kalaeloa CT's			2 Kalaeloa CT's, 1 Kahe			2 Kalaeloa CT's, 2 Kahe		
		Trip	Cont Res		Min Freq	Cont Res		Min Freq	Cont Res		Min Freq	Cont Res		Min Freq
Avail	Curt	(MW)	MW	%	(Hz)	MW	%	(Hz)	MW	%	(Hz)	MW	%	(Hz)
272	272	200	0	0	56.8	0	0%	57.7	0	0%	57.8	0	0%	58.0
			20	7%	57.6	20	7%	57.8	20	7%	58.0	20	7%	58.1
			40	15%	57.8	40	15%	58.0	40	15%	58.1	40	15%	58.3
			60	22%	57.9	60	22%	58.1	60	22%	58.3	60	22%	58.4
			80	29%	58.1	80	29%	58.3	80	29%	58.4	80	29%	58.6
			100	37%	58.3	100	37%	58.5	100	37%	58.7	100	37%	58.7
			120	44%	58.6	120	44%	58.7	120	44%	59.3	120	44%	59.5
			140	51%	59.9	140	51%	60.0	140	51%	60.0	140	51%	60.0
			160	59%	58.9	160	59%	59.1	160	59%	59.2	160	59%	59.4
		100	0	0%	58.2	0	0%	58.4	0	0%	58.5	0	0%	58.7
			20	7%	58.4	20	7%	58.6	20	7%	58.7	20	7%	59.4
			40	15%	59.9	40	15%	59.9	40	15%	60.0	40	15%	60.0
			60	22%	58.9	60	22%	58.9	60	22%	59.2	60	22%	59.3
			80	29%	59.8	80	29%	59.8	80	29%	59.9	80	29%	59.9
			100	37%	60.0	100	37%	60.0	100	37%	60.0	100	37%	60.0
			120	44%	60.0	120	44%	60.0	120	44%	60.0	120	44%	60.0
			140	51%	60.0	140	51%	60.0	140	51%	60.0	140	51%	60.0
			160	59%	60.0	160	59%	60.0	160	59%	60.0	160	59%	60.0

percent of curtailed station PV used for regulation
minimum ESS / Station PV regulation size
frequency below limits of 58.7 Hz

Table D-32. 2017 Day Minimum Detailed Results

The night minimum case results are shown in Table D-33, and show that for an AES trip of 200 MW, an additional 80 MW of contingency reserves is required. No additional contingency reserves are required for a trip of AES at 100 MW.

BESS Size	AES Trip	Cont Res MW	Min Freq (Hz)
60	200	0	58.2
		20	58.3
		40	58.4
		60	58.6
		80	58.8
		100	58.9
		120	59.3
		140	60.0
		160	60.0
	100	0	59.0
		20	59.5
		40	60.0
		60	60.0
		80	60.0
		100	60.0
		120	60.0
		140	60.0
		160	60.0

minimum ESS size
frequency below limits of 58.7

Table D-33. 2017 Night Minimum Detailed Results

YEAR 2022 ANALYSIS

Power flow cases were created for the day minimum load times. The day minimum cases assumed a load of 752 MW, with renewable generation resources consisting of 556 MW of distributed PV (40 MW legacy PV), 272 MW of station PV, and 123 MW of wind. A 60 MW BESS is assumed to be installed in 2017 and available for use in 2022.

Contract requirements for AES were assumed to be 90 MW/180 MW. Generation additions included the options of utilizing GE LM6000 or LMS100 combustion turbines, with nominal ratings of 55 MW and 95 MW, respectively.

2022 Generation Dispatches

The dispatches created all utilized AES dispatched at 100 MW or 200 MW, while the remaining generation support came from the new LM6000s or LMS100s identified in the PSIP preferred plan. The new units were dispatched at their minimum output of 12 MW. Details of the generation dispatches for the daytime minimum cases are shown in Table D-34.

Unit	LMS100				LM6000			
	1		2		2		3	
	AES		AES		AES		AES	
	200	100	200	100	200	100	200	100
LMS100 #1	12	12	12	12	-	-	-	-
LMS100 #2	-	-	12	12	-	-	-	-
LM6000 #1	-	-	-	-	12	12	12	12
LM6000 #2	-	-	-	-	12	12	12	12
LM6000 #2	-	-	-	-	-	-	12	12
AES	200	100	200	100	200	100	200	100
Total Thermal	212	112	224	124	224	124	236	136
Wind	123	123	123	123	123	123	123	123
PV - DG	556	556	556	556	556	556	556	556
PV - Station	272	272	272	272	272	272	272	272
Total Renewable	951	951	951	951	951	951	951	951
RE Curtailed	396	296	408	308	408	308	420	320
Total PV available	432	532	420	520	420	520	408	508
Total 57 available	392	492	380	480	380	480	368	468
Total Renewable available	555	655	543	643	543	643	531	631
Load - day min	752	752	752	752	752	752	752	752
Losses (assumed)	15	15	15	15	15	15	15	15

Table D-34. 2022 Day Minimum Generation Dispatch

2022 Results

The day minimum cases show that for a 200 MW trip of AES, utilizing the already installed 60 MW BESS requires an additional 140 MW of contingency reserves. For a

100 MW trip of AES, 40 MW of additional contingency reserves is needed. Detailed results for the day minimum cases using generation from LM6000s or LMS100s are shown below in Table D-35 and Table D-36, respectively.

Station PV		BESS Size (MW)	AES Unit Trip (MW)	LM6000							
				2				3			
				Cont Reserve		Unit Trip		Cont Reserve		Unit Trip	
Avail	Curt			MW	%	AES	Wind	MW	%	AES	Wind
272	272	60	100	0	0%	57.8	58.3	0	0%	58.1	58.4
				20	7%	58.2	58.6	20	7%	58.4	58.7
				40	15%	59.9	59.6	40	15%	59.9	59.7
				60	22%	58.7	60.0	60	22%	58.8	60.0
				80	29%	59.6	59.5	80	29%	59.6	59.5
				100	37%	60.0	60.0	100	37%	60.0	59.9
				120	44%	60.0	60.0	120	44%	60.0	60.0
				140	51%	60.0	60.0	140	51%	60.0	60.0
				160	59%	60.0	60.0	160	59%	60.0	60.0
			200	0	0%	55.4	58.3	0	0%	56.5	58.5
				20	7%	56.7	58.6	20	7%	57.1	58.7
				40	15%	57.0	59.6	40	15%	57.4	59.7
				60	22%	57.3	60.0	60	22%	57.7	60.0
				80	29%	57.6	59.5	80	29%	57.9	59.5
				100	37%	58.0	60.0	100	37%	58.2	59.9
				120	44%	58.2	60.0	120	44%	58.5	60.0
				140	51%	60.0	60.0	140	51%	59.9	60.0
				160	59%	58.8	60.0	160	59%	58.9	60.0
					percent of curtailed station PV used for regulation						
					Additional Regulation from Station PV required						
					Simulation Results in frequency below 58.7 Hz						

Table D-35. 2022 Day Minimum LM6000 Units Detailed Results

Station PV		BESS Size (MW)	AES Unit Trip (MW)	LMS100							
				1				2			
				Cont Reserve		Unit Trip		Cont Reserve		Unit Trip	
Avail	Curt			MW	%	AES	Wind	MW	%	AES	Wind
272	272	60	100	0	0%	57.7	58.3	0	0%	58.2	58.5
				20	7%	58.2	58.6	20	7%	58.5	58.8
				40	15%	59.9	59.6	40	15%	59.9	59.7
				60	22%	58.7	60.0	60	22%	58.9	60.0
				80	29%	59.6	59.5	80	29%	59.6	59.5
				100	37%	60.0	60.0	100	37%	60.0	59.8
				120	44%	60.0	60.0	120	44%	60.0	60.0
				140	51%	60.0	60.0	140	51%	60.0	60.0
				160	59%	60.0	60.0	160	59%	60.0	60.0
			200	0	0%	54.6	58.3	0	0%	56.5	58.5
				20	7%	56.2	58.6	20	7%	57.2	58.8
				40	15%	56.7	59.6	40	15%	57.5	59.7
				60	22%	57.2	60.0	60	22%	57.8	60.0
				80	29%	57.5	59.5	80	29%	58.0	59.6
				100	37%	57.9	60.0	100	37%	58.2	59.9
				120	44%	58.1	60.0	120	44%	58.6	60.0
				140	51%	60.0	60.0	140	51%	59.9	60.0
				160	59%	58.8	60.0	160	59%	59.0	60.0
					percent of curtailed station PV used for regulation						
					Additional Regulation from Station PV required						
					Simulation Results in frequency below 58.7 Hz						

Table D-36. 2022 Day Minimum LMS100 Units Detailed Results

YEAR 2030 ANALYSIS

Power flow cases were created for the day minimum load times. The day minimum cases assumed a load of 752 MW, with renewable generation resources consisting of 556 MW of distributed PV (40 MW legacy PV), 272 MW of station PV, and 123 MW of wind.

The 60 MW BESS assumed to be operational in 2017 is incorporated into this analysis as available for use in 2030.

Generation was assumed to be only from new generation resources of either GE LM6000s or LMS100s combustion turbines, with nominal ratings of 55 MW and 95 MW, respectively.

2030 Generation Dispatches

The dispatches created all utilized AES dispatched at 100 MW and 200 MW, while the remaining generation support came from the new LM6000s or LMS100s, dispatched at their minimum output of 12 MW. Details of the generation dispatches for the daytime minimum and daytime peak cases are shown in Table D-37.

Unit	Day Minimum				Day Peak			
	LM6000		LMS100		LM6000		LMS100	
	2	3	2	3	2	3	2	3
# of LM6000	2	3	-	-	2	3	-	-
# of LMS100	-	-	2	3	-	-	2	3
Total Thermal	110	165	190	285	110	165	190	285
Wind	123	123	123	123	123	123	123	123
PV - DG	556	556	556	556	556	556	556	556
PV - Station	272	272	272	272	272	272	272	272
Total Renewable	951	951	951	951	951	951	951	951
RE Curtailed	294	349	374	469	202	257	282	377
Total PV available	534	479	454	359	626	571	546	451
Total 57 available	494	439	414	319	586	531	506	411
Total Renewable available	657	602	577	482	749	694	669	574
Load - day min	752	752	752	752	844	844	844	844
Losses (assumed)	15	15	15	15	15	15	15	15

Table D-37. 2030 Day Minimum and Day Peak Generation Dispatches

Details of the generation dispatches for the evening peak and night time minimum cases are shown in Table D-38.

Unit	Evening Peak		Night Minimum	
	LM6000	LMS100	LM6000	LMS100
	14	8	9	5
# of LM6000	14	-	9	-
# of LMS100	-	8	-	5
Total Thermal	770	760	495	475
Wind	123	123	123	123
PV - DG	-	-	-	-
PV - Station	-	-	-	-
Total Renewable	123	123	123	123
RE Curtailed	-	-	-	-
Total PV available	-	-	-	-
Total 57 available	-	-	-	-
Total Renewable available	123	123	123	123
Load - day min	924	924	635	635
Losses (assumed)	15	15	15	15

Table D-38. 2030 Evening Peak and Night Minimum Generation Dispatches

2030 Results

Outages of the largest combustion turbine and wind generation facility were analyzed for each case. The day minimum cases show that for a generation dispatch of two or three LM6000's, a 100 MW trip of a wind generation facility will require an additional 40 MW of contingency reserves. Detailed results for the day minimum LM6000 cases are shown below in Table D-39.

Station PV		LM6000							
		2				3			
Avail	Curt	Cont Reserve		Disturbance		Cont Reserve		Disturbance	
		MW	%	Unit	Wind	MW	%	Unit	Wind
272	272	0	0%	60.0	58.1	0	0%	60.0	58.3
		20	7%	58.8	58.2	20	7%	59.1	58.5
		40	15%	60.0	59.5	40	15%	59.9	59.7
		60	22%	60.0	58.7	60	22%	60.0	58.8
		80	29%	60.0	59.3	80	29%	60.0	59.4
		100	37%	60.0	59.9	100	37%	60.0	59.9
		120	44%	60.0	60.0	120	44%	60.0	60.0
			percent of curtailed station PV used for regulation						
			Additional ESS / Regulation Required						
			Simulation Results in frequency below 58.7 Hz						

Table D-39. 2030 Day Minimum LM6000 Units Detailed Results

The day minimum cases show that for a generation dispatch of two or three LM100's, a 100 MW trip of a wind generation facility or of an LMS100 will require an additional 40 MW of contingency reserves. Detailed results for the day minimum LMS100 cases are shown below in Table D-40.

Station PV		LMS100							
		2				3			
Avail	Curt	Cont Reserve		Disturbance		Cont Reserve		Disturbance	
		MW	%	Unit	Wind	MW	%	Unit	Wind
272	272	0	0%	58.0	58.5	0	0%	58.5	58.6
		20	7%	58.4	58.7	20	7%	59.5	59.5
		40	15%	60.0	59.8	40	15%	60.0	59.9
		60	22%	59.2	59.0	60	22%	59.4	59.3
		80	29%	60.0	59.5	80	29%	59.9	59.7
		100	37%	60.0	59.9	100	37%	60.0	59.9
		120	44%	60.0	60.0	120	44%	60.0	60.0

(grey)	percent of curtailed station PV used for regulation
(blue)	Additional ESS / Regulation Required
(pink)	Simulation Results in frequency below 58.7 Hz

Table D-40. 2030 Day Minimum LMS100 Units Detailed Results

The day peak cases show that for a generation dispatch three LM6000's, a 100 MW trip of a wind generation facility will require will require an additional 40 MW of contingency reserves. Detailed results for the day peak LM6000 cases are shown below in Table D-41.

Station PV		LM6000			
		3			
Avail	Curt	Cont Reserve		Disturbance	
		MW	%	Unit	Wind
272	272	0	0%	60.0	58.4
		20	7%	59.1	58.5
		40	15%	59.9	59.6
		60	22%	60.0	58.8
		80	29%	60.0	59.4
		100	37%	60.0	59.8
		120	44%	60.0	60.0

(grey)	percent of curtailed station PV used for regulation
(blue)	Additional ESS / Regulation Required
(pink)	Simulation Results in frequency below 58.7 Hz

Table D-41. 2030 Day Peak LM6000 Units Detailed Results

The day peak cases show that for a generation dispatch of two or three LM100s, a 100 MW trip of a wind generation facility or of an LMS100 will require an additional 40 MW of contingency reserves. Detailed results for the day peak LMS100 cases are shown below in Table D-42.

Station PV		LMS100							
		2				3			
Avail	Curt	Cont Reserve		Disturbance		Cont Reserve		Disturbance	
		MW	%	Unit	Wind	MW	%	Unit	Wind
272	272	0	0%	58.1	58.5	0	0%	58.5	58.6
		20	7%	58.4	58.6	20	7%	59.5	59.5
		40	15%	60.0	59.7	40	15%	60.0	59.9
		60	22%	59.2	58.9	60	22%	59.4	59.2
		80	29%	60.0	59.5	80	29%	59.9	59.6
		100	37%	60.0	59.8	100	37%	60.0	59.9
		120	44%	60.0	60.0	120	44%	60.0	60.0
			percent of curtailed station PV used for regulation						
			Additional ESS / Regulation Required						
			Simulation Results in frequency below 58.7 Hz						
			marginal case, not recommended for sizing regulation needed						

Table D-42. 2030 Day Peak LMS100 Units Detailed Results

The evening peak cases show that for a generation dispatch utilizing either 14 LM6000s or 8 LMS100s results in no additional need for contingency reserves beyond the assumed to be installed 60 MW BESS. Detailed results for the evening peak cases are shown below in Table D-43.

LM6000			LMS100		
14			8		
Cont Reserve	Disturbance		Cont Reserve	Disturbance	
MW	Unit	Wind	MW	Unit	Wind
0	60.0	59.6	0	59.6	59.6
20	60.0	59.8	20	59.8	59.8
40	60.0	60.0	40	60.0	60.0
60	60.0	60.0	60	60.0	60.0
80	60.0	60.0	80	60.0	60.0
100	60.0	60.0	100	60.0	60.0
120	60.0	60.0	120	60.0	60.0
	Additional ESS / Required				
	Simulation Results in frequency below 58.7 Hz				

Table D-43. 2030 Evening Peak Detailed Results

The night minimum cases show that for a generation dispatch utilizing either 14 LM6000s or 8 LMS100s results in no additional need for contingency reserves beyond the assumed to be installed 60 MW BESS. Detailed results for the night minimum cases are shown below in Table D-44.

LM6000			LMS100		
9			5		
Cont Reserve	Disturbance		Cont Reserve	Disturbance	
MW	Unit	Wind	MW	Unit	Wind
0	60.0	59.4	0	59.4	59.5
20	60.0	59.7	20	59.7	59.8
40	60.0	60.0	40	60.0	60.0
60	60.0	60.0	60	60.0	60.0
80	60.0	60.0	80	60.0	60.0
100	60.0	60.0	100	60.0	60.0
120	60.0	60.0	120	60.0	60.0
	Additional ESS / Required				
	Simulation Results in frequency below 58.7 Hz				

Table D-44. 2030 Night Minimum Detailed Results

2030 Results: No Additional ESS Contingency Reserves

Further analysis determined the minimum number of units required to be online with contingency reserve resources limited to the 60 MW BESS for the day minimum cases. The analysis was completed utilizing LM6000 or LMS100 combustion turbines. Utilizing LM6000 units requires that at minimum 7 units be online in order to keep the system frequency above 58.7 Hz. Utilizing LMS100 units requires that a minimum of 5 units be online. The detailed results are shown below in Table D-45.

Case	BESS Size (MW)	Reg	LM6000			LMS100		
			# of Units	Contingency		# of Units	Contingency	
				LM6000	Wind		LMS100	Wind
day min	60	198	5	59.8	58.5	3	60.0	58.6
			6	60.0	58.6	4	58.6	58.8
			7	60.0	58.8	5	58.8	59.4
			8	60.0	59.4	6	59.4	59.5
			9	60.0	59.5	7	59.5	59.6
			10	60.0	59.5	-	-	-
				Minimum number of units required				
				Simulation Results in frequency below 58.7 Hz				

Table D-45. 2030 Minimum Number of Unit Analysis

CONCLUSIONS

EPS has completed analysis of the Hawaiian Electric system for the 2015–2030 time periods. These periods were chosen in order to determine the operation ability and any constraints on the operations of the Hawaiian Electric system before the addition of additional transmission infrastructure and energy storage systems that are expected to come online in 2017, and after improvements have been made.

2015–2016 Cases

The results of the analysis show that there is a benefit to the system in reducing the amount of legacy PV from 60 MW to 40 MW of total output. The reduction in legacy PV can decrease the amount of UFLS activation during contingencies and also allows for better system response during Zone 2 clearing of transmission lines.

The analysis also clearly shows the importance of upgrading the transmission protection system to eliminate the need for Zone 2 clearing of transmission lines. Zone 2 clearing of transmission lines can results in stage 1 and stage 2 UFLS activation during contingencies.

Analysis was completed to determine the impact on the Hawaiian Electric system due to a trip of the AES unit at different load levels. Transfer trip schemes for UFLS activation were utilized in order to mitigate UFLS activation to only stages 1 or stages 1 and 2.

The result of this analysis is shown in Table D-46 for the 2015 load season. The results show the maximum AES output while allowing for either Stage 1 UFLS activation, or Stage 1 and Stage 2 UFLS activation. Reducing the legacy PV amounts from 60 to 40 MW results in an increase in AES output by 20 MW. Utilizing up to Stage 2 UFLS activation allows in an increase in AES output by up to 20 MW for some cases. The max unit dispatch cases (day peak and night minimum) show that benefit to the transmission system to having additional units online for system support, primarily from their added inertia.

Load	Legacy PV	Max AES Trip, with and without UFLS				
		Up To Stage 1		Up To Stage 2		
		Transfer Trip UFLS		Transfer Trip UFLS		
		0	1	0	1	2
day min	40	< 80	< 80	< 80	< 80	< 80
	60	< 80	< 80	< 80	< 80	< 80
day peak	40	<100	<100	120	120	140
	60	<100	<100	100	120	120
day peak, max units	40	140	160	200	200	200
	60	120	140	180	200	200
evening peak	-	160	180	200	200	200
night minimum	-	< 100	< 100	100	100	120
night min, max units	-	120	120	140	140	160
			minimum output not found			

Table D-46. 2015 Maximum AES Output

The result of this analysis is shown in Table D-47 for the 2016 load season. As with the 2015 case results, reducing the legacy PV amounts from 60 to 40 MW results in an increase in AES output by 20 MW. Utilizing up to Stage 2 UFLS activation allows in an increase in AES output by up to 20 MW for some cases. The max unit dispatch cases (day peak and night minimum) show that benefit to the transmission system to having additional units online for system support, primarily from their added inertia.

Comparing the 2015 and 2016 case results also show that utilization of the new unit minimums (down from 24 MW to 10 MW) can allow for an increase in units online, further increasing the system response during under frequency events.

Load	Legacy PV	Max AES Trip, with and without UFLS				
		Up To Stage 1		Up To Stage 2		
		Transfer Trip UFLS		Transfer Trip UFLS		
		0	1	0	1	2
day min	40	< 80	< 80	80	80	80
	60	< 80	< 80	< 80	< 80	80
day peak	40	<100	100	140	140	140
	60	<100	100	120	120	140
day peak, max units	40	100	120	160	160	180
	60	<100	100	140	160	160
evening peak	-	160	180	200	200	200
night minimum	-	< 100	< 100	100	120	120
night min, max units	-	120	140	160	180	180
			minimum output not found			

Table D-47. 2016 Maximum AES Output

The following recommendations are based on the analysis and results of the study:

- Upgrade transmission system protection to eliminate need for Zone 2 clearing of transmission lines.
- Reduce the amount of legacy PV installed on the system by changing over to extended PV settings.
- Incorporate the ability to reduce the minimum output limits of generators.
- Dispatch additional units as possible as needed to mitigate UFLS activation for expected contingencies.
- Utilize a transfer – trip scheme that will activate stages of UFLS for outages of AES.

2017+ Cases

EPS has completed analysis for the Hawaiian Electric system defining the boundary conditions as to the operations of the system for the 2017, 2022, and 2030 case years. The boundary conditions represent the likely operating requirements due to the large additions of renewable energy and changes in load expected in the future.

To aid in clarifying the different results, security tables were created showing the operating requirements for each year and each configuration within that year.

The security tables include data values as to the minimum number for thermal units required, the ramp rate requirements, the regulation requirements, contingency and 30-minute reserves, and required voltage support.

The ramp rate requirement was assumed to be 10% per minute for both PV and wind energy resources. This value was derived from analysis EPS has completed that is not part of this report.

The regulation requirements include values for day time and night time periods. The daytime regulation reserve is calculated as the summation of 20% of the installed DG PV, 35% of installed station PV, and 50% of the installed wind. The night time regulation reserve is calculated as only 50% of the installed wind.

The contingency reserve is calculated as the amount of reserves (energy storage and/or PV regulation) required in order to meet criteria for the largest unit or wind generation facility outage. The 30-minute reserves are equal to the largest unit or wind generation facility outage and is the required amount of energy to be brought online to displace the short term contingency reserves.

2017 Security Tables

The security tables for the 2017 time frame include tables for a 200 MW and 100 MW AES trip. The 2017 cases require a minimum of 4 thermal units online. The day time regulation reserves are 210 MW, with night time reserves of 62 MW, and a ramp rate requirement of 86.6 MW per min. Contingency and 30-minute reserves are 200 MW of the 200 MW AES trip case and 100 MW each for the 100 MW AES trip case. The security tables for the two cases are shown in Table D-48 and Table D-49, respectively.

<table>
<tr><th colspan="2">Value</th><th>Capacity (MW)</th><th># of Thermal units required</th><th>Ramp Rate Requirements</th><th>Regulation Reserves - Day time</th><th>Regulation Reserves - Night time</th><th>Contingency Reserves</th><th>30 Minute Reserves</th><th>Voltage Support (SVC)</th></tr>
<tr><td rowspan="2">PV Level</td><td>Station</td><td>272</td><td rowspan="4">4</td><td rowspan="4">86.6 MW / Min</td><td rowspan="4">281 MW
(20% of DG PV+ 35% Station PV + 50% Wind)</td><td rowspan="4">62 MW
(50% of Wind)</td><td rowspan="4">200 MW</td><td rowspan="4">200 MW</td><td rowspan="4">+/- 80 MVAr</td></tr>
<tr><td>DG</td><td>471</td></tr>
<tr><td colspan="2">Wind</td><td>123</td></tr>
<tr><td colspan="2">Largest Unit</td><td>200</td></tr>
</table>

Table D-48. 2017 Security Table: 200 MW AES Trip

<table>
<tr><th colspan="2">Value</th><th>Capacity (MW)</th><th># of Thermal units required</th><th>Ramp Rate Requirements</th><th>Regulation Reserves - Day time</th><th>Regulation Reserves - Night time</th><th>Contingency Reserves</th><th>30 Minute Reserves</th><th>Voltage Support (SVC)</th></tr>
<tr><td rowspan="2">PV Level</td><td>Station</td><td>272</td><td rowspan="4">4</td><td rowspan="4">86.6 MW / Min</td><td rowspan="4">281 MW
(20% of DG PV+ 35% Station PV + 50% Wind)</td><td rowspan="4">62 MW
(50% of Wind)</td><td rowspan="4">100 MW</td><td rowspan="4">100 MW</td><td rowspan="4">+/- 80 MVAr</td></tr>
<tr><td>DG</td><td>471</td></tr>
<tr><td colspan="2">Wind</td><td>123</td></tr>
<tr><td colspan="2">Largest Unit</td><td>100</td></tr>
</table>

Table D-49. 2017 Security Table: 100 MW AES Trip

2022 Security Tables

The security tables for the 2022 time frame include tables for a 100 MW AES trip utilizing additional generation support from either LM6000 units or LMS100 units. The 2022 cases require a minimum of 3 thermal units utilizing LM6000s and only 2 thermal units utilizing LMS100s. The day time regulation reserves are 227 MW, with night time reserves of 62 MW, and a ramp rate requirement of 95.1 MW per min. Contingency and 30-minute reserves are 100 MW for each case. The security tables for the two cases are shown in Table D-50 and Table D-52, respectively.

<table>
<tr><th colspan="2">Value</th><th>Capacity (MW)</th><th># of Thermal units required</th><th>Ramp Rate Requirements</th><th>Regulation Reserves - Day time</th><th>Regulation Reserves - Night time</th><th>Contingency Reserves</th><th>30 Minute Reserves</th><th>Voltage Support (SVC)</th></tr>
<tr><td rowspan="2">PV Level</td><td>Station</td><td>272</td><td rowspan="4">3
AES + 2 LM6000</td><td rowspan="4">95.1 MW / Min</td><td rowspan="4">311 MW
(20% of DG PV+ 35% Station PV + 50% Wind)</td><td rowspan="4">62 MW
(50% of Wind)</td><td rowspan="4">100 MW</td><td rowspan="4">100 MW</td><td rowspan="4">+/- 80 MVAr</td></tr>
<tr><td>DG</td><td>556</td></tr>
<tr><td colspan="2">Wind</td><td>123</td></tr>
<tr><td colspan="2">Largest Unit</td><td>100</td></tr>
</table>

Table D-50. 2022 Security Table: AES + LM6000 Units

Value		Capacity (MW)	# of Thermal units required	Ramp Rate Requirements	Regulation Reserves - Day time	Regulation Reserves - Night time	Contingency Reserves	30 Minute Reserves	Voltage Support (SVC)
PV Level	Station	272	2 AES + 1 LMS100	95.1 MW / Min	311 MW (20% of DG PV+ 35% Station PV + 50% Wind)	62 MW (50% of Wind)	100 MW	100 MW	+/- 80 MVAr
	DG	556							
Wind		123							
Largest Unit		100							

Table D-51. 2022 Security Table: AES + LMS100 Units

2030 Security Tables

The security tables for the 2030 time frame include tables for cases utilizing generation support from either LM6000 units or LMS100 units. The 2030 cases require a minimum of 3 LM6000s or only 2 LMS100s. The day time regulation reserves are 242 MW, with night time reserves of 62 MW, and a ramp rate requirement of 102.6 MW per min. Contingency and 30-minute reserves are 100 MW for each case. The security tables for the two cases are shown in Table D-52 and Table D-53, respectively.

Value		Capacity (MW)	# of Thermal units required	Ramp Rate Requirements	Regulation Reserves - Day time	Regulation Reserves - Night time	Contingency Reserves	30 Minute Reserves	Voltage Support (SVC)
PV Level	Station	272	7	95.1 MW / Min	337 MW (20% of DG PV+ 35% Station PV + 50% Wind)	62 MW (50% of Wind)	60 MW	100 MW	+/- 80 MVAr
	DG	631							
Wind		123							
Largest Unit		100							

Table D-52. 2030 LM6000 Units

Value		Capacity (MW)	# of Thermal units required	Ramp Rate Requirements	Regulation Reserves - Day time	Regulation Reserves - Night time	Contingency Reserves	30 Minute Reserves	Voltage Support (SVC)
PV Level	Station	272	5	95.1 MW / Min	337 MW (20% of DG PV+ 35% Station PV + 50% Wind)	62 MW (50% of Wind)	60 MW	100 MW	+/- 80 MVAr
	DG	631							
Wind		123							
Largest Unit		100							

Table D-53. 2030 LMS100 Units

The security tables were also created for the 2030 cases assuming only the 60 MW ESS is available for contingency reserves. Utilizing only the 60 MW ESS requires a minimum of 7 LM6000s or 5 LMS100s. The day time regulation reserves are 242 MW, with night time reserves of 62 MW, and a ramp rate requirement of 102.6 MW per min. Contingency reserves are 60 MW and 30-minute reserves are 100 MW for each case. The security tables for the two cases are shown in Table D-54 and Table D-55, respectively.

Value		Capacity (MW)	# of Thermal units required	Ramp Rate Requirements	Regulation Reserves - Day time	Regulation Reserves - Night time	Contingency Reserves	30 Minute Reserves	Voltage Support (SVC)
PV Level	Station	272	3	95.1 MW / Min	337 MW (20% of DG PV+ 35% Station PV + 50% Wind)	62 MW (50% of Wind)	100 MW	100 MW	+/- 80 MVAr
	DG	631							
Wind		123							
Largest Unit		100							

Table D-54. 2030 MIN LM6000 Units 60 MW BESS

Value		Capacity (MW)	# of Thermal units required	Ramp Rate Requirements	Regulation Reserves - Day time	Regulation Reserves - Night time	Contingency Reserves	30 Minute Reserves	Voltage Support (SVC)
PV Level	Station	272	2	95.1 MW / Min	337 MW (20% of DG PV+ 35% Station PV + 50% Wind)	62 MW (50% of Wind)	100 MW	100 MW	+/- 80 MVAr
	DG	631							
Wind		123							
Largest Unit		100							

Table D-55. 2030 MIN LMS100 Units 60 MW BESS

E. Essential Grid Services

Grid services include generating capacity plus ancillary services, which are both essential to reliable system operation. Generating capacity is used to meet load demands; ancillary services supplement the generating capacity to help meet demand or correct frequency deviations that occur as a result of normal changes in load and generation, as well as the result of abnormal transient events. Ancillary services can occur in layers, with some taking longer to act than others. The system operator needs to designate which ancillary services are necessary for the system characteristics at the time.

Synchronous generation has traditionally provided generating capacity and ancillary services. Increasing amounts of variable generation, however, diminish the amount of dispatchable generation on the system and the ability of dispatchable generation to provide the needed ancillary services. In many cases, the variable generation resources do not provide the level of ancillary services required for the system's security. In addition, the potential loss of variable distributed generation (whether due to large ramping events or trips due to transient events) has become the largest contingency for which many of the ancillary services must be designed.

For these reasons, new generation resources must have the ability to also provide required ancillary services, or new systems that can provide the ancillary services must be added. Variable generation costs should include the cost of periodic testing and maintenance of their accompanying ancillary systems to ensure the reliability of the electric system. The variable generation protection and control devices should be tested and verified at installation, and tested and maintained periodically after that. Every device should be calibrated and tested at least every three years.

GRID SERVICES

Capacity

Capacity is the maximum reliable amount of electrical output available from a resource. Systems must be operated to ensure there is sufficient capacity online to meet demand in the near term. Systems must be planned and designed to ensure that there is adequate supply of capacity to meet future demands. For dispatchable generation, the capacity is the maximum power output of the generating unit[1]. For variable generation (such as wind or solar power), capacity in the near term is the minimum available amount of output expected in the next one to three hours. The capacity of controlled load in the near term is the minimum level of load under control during each of the four six-hour planning periods of a 24-hour day.

For planning capacity margins, the capacity contribution for variable generation is developed by examining the historical availability during the peak demand periods, to determine the amount of capacity which is very probable to be available in the peak period. Similarly, demand response could contribute to capacity if it is available during the peak period. To count as capacity, the generation does not have to be under automatic generation control (AGC) to reach its maximum rating. Unit control can be by AGC, by human intervention, or a combination, so long as the output is controllable and predictable.

Capacity does not have a response time requirement. However, as stated above, it must be reliably available for a period of time.

Generation capacity should be modeled and tested consistent with HI-Mod-0010 and HI-Mod-0025.[2] Controlled load capacity should be modeled and tested in accordance with capacity testing and modeling requirements for conventional generation capacity. Controlled load will need periodic review and exercising to confirm its stated capacity, as the load characteristics change over time.

1 Generators are designed higher than its prime mover's capability, therefore the generator's nameplate rating can sometimes be higher than what it actually produces.

2 HI-Mod-0010 is the proposed Hawaiian standard for modeling unit capacity used for system studies. HI-Mod-0025 is the proposed Hawaiian standard for testing unit capacity to confirm its model for use in electrical studies.

ANCILLARY SERVICES

Regulating Reserve

Regulating reserve is the amount of unloaded capacity of regulation resources that can be used to match system demand with generation resources and maintain normal frequency. Use of regulating reserve is governed by a command from Automatic Generation Control (AGC) to a change in system demand. A change in system demand results in a change in system frequency, and the AGC program will adjust the generating units under its control to return system frequency to the normal state. A regulation resource is a resource that immediately responds, without delay, to commands from AGC to predictably increase or decrease its generation output. Regulation resources must accurately and predictably respond to AGC commands throughout their range of operation.

Regulation resources can also include non-traditional resources such as controlled loads or storage, providing the necessary control capabilities and response for the AGC interface. Non-generation resources participating in regulation must be capable of sustaining the maximum increase or decrease for at least 30 minutes.

Regulating reserve is used to counter normal changes in load or variable generation. Changes in generation output or controlled loads must be completed within 2 seconds of the AGC command, and must be controllable by AGC to a resolution of 0.1 MW.

In our islanded power system, regulation resources are constantly used to balance load and generation to maintain a 60 Hz frequency reference. The number of controls to regulating resources is greater than larger systems, due to a combination of the impacts of the small system size, its isolation, and the amount of variable wind and solar generation on the systems whose variable output requires additional adjustments from regulating resources. As a result, it has been typical on the island systems that all online resources capable of participating in regulation are used for regulation.

If demand response or storage are used for regulation, the cost of modifying the AGC system to be able to utilize these non-traditional resources as a regulation resource should be included in valuation of these alternate resources. The implementation must include special considerations specific to non-generation resources, such as the need to adopt the regulation algorithms to consider that the limits of the storage or demand response (that is, the response cannot be sustained indefinitely, unlike a dispatchable generator), and to include the rotation of DR within the group to limit impact on DR resources of the same type.

Contingency Reserve

Each of the Companies' systems must be operated such that the system remains operable and the grid frequency can be quickly restored following a contingency situation wherein a generating or transmission resource on the island suddenly trips offline. This can be the largest single unit, the largest combination of dependent units (such as combined cycle units), or the loss of a single transmission line connecting a large generation unit to the system. The contingency reserve is the reserve designated by a system operator to meet these requirements.

Conventional generation, stored energy resources, curtailed variable generation, load shed or DR resources can provide contingency reserves.

Contingency reserves carried on generator resources, including storage, must respond automatically to changes in the system frequency, with a droop response determined by the system operator.

The island systems are unique in that all imbalances between supply and demand result in a change in system frequency. There are no interconnections to draw additional power from in the event of loss of generation. As a result, the island systems rely heavily upon instantaneous underfrequency load-shed to provide protection reserves and contingency reserves. If participating in the instantaneous protection, which may be used for contingency reserves or system protection, DR or load shed must be accurate to ± 0.02 Hz and ± 0.0167 cycles. The response time from frequency trigger to load removal can be no more than 7 cycles.

DR that cannot meet the 7-cycle requirement may be used for a time-delay, or the "kicker block" of under frequency load-shed. This block of load-shed is used for smaller increments of generation loss than the contingency reserves (set at a higher frequency set-point than the faster, instantaneous load-shed). Resources deployed for time-delay load-shed must be controllable within an accuracy of ± 0.02 Hz and ± 0.02 seconds, and have a response time from frequency trigger to load removal adjustable in increments of 0.5 seconds up to 30 seconds, to be considered for use as time delay load-shed.

To ensure consistent performance, DR controls and loads used for contingency reserve should be tested and certified annually. (See HI-Mod-012, HI-Mod-010, and HI-Mod-025, 26, 27.[3]) Annual costs for testing and certification should be included in the total cost for these provisions.

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[3] HI-Mod-0012 is the proposed Hawaiian standard for modeling and reporting the dynamic response of system models and results of simulations using these models. HI-Mod-0260 is the proposed Hawaiian standard for verifying plant or excitation equipment used in system models. HI-MOD-0027 is the proposed Hawaiian standard for verifying the models for turbine/governor and frequency control functions.

Controllable load used in any other DR program cannot be included in the loads designated as contingency reserves. The impacts of any DR use on the instantaneous underfrequency load-shed schemes must be evaluated and incorporated into the design to ensure adequate system protection remains.

10-Minute Reserve

Off-line, quick-start resources can be used as 10-minute reserves provided they can be started and synchronized to the grid in 10 minutes or less. These resources may be used for restoring regulation or contingency reserves.

When conditions warrant, a system operator starts the 10-minute reserve resource remotely, and automatically synchronizes it to the power system. The system operator then either loads the resource to a predetermined level, or places it under AGC control, either of which must be completed within 10 minutes. The 10-minute reserve must be able to provide the declared output capability for a minimum of two hours.

The resource can be any resource with a known output capability. Resources can include generators, storage, and controllable loads. A system operator must be able to control these resources to restore regulation or contingency reserves.

30-Minute Reserve

Off-line, 30-minute reserve resources shall be resources that can be operated during normal load and generation conditions, and can be started and synchronized to the grid in 30 minutes or less. They can be counted as capacity resources to meet expected load and demand, or to restore contingency reserves.

When conditions warrant, a system operator starts the resource remotely, synchronizes it, and (if participating in regulating reserves) places it under AGC control within 30 minutes; when it must then be able to serve the capacity for at least three hours.

The 30-minute reserve resource can be any resource with a known capacity. A system operator must be able to control these load resources to restore contingency or regulation reserves.

Long Lead-Time Reserve

Resources that take longer than 30 minutes to be started, synchronized, and placed under AGC control (if participating in regulating reserves) are considered long lead-time reserves. They can be operated during normal load and generation conditions. These resources may be used as capacity resources to meet expected load and demand, and for restoring contingency reserves.

Long lead-time reserves can include any resource with a known capacity. System operators must be able to control these load resources to restore contingency reserves.

Long-lead time resources can be used to meet forecast peak demand, in addition to restoring contingency reserves or the replacement of fast-start reserves. Long-lead time reserves must be able to serve the capacity for at least three hours.

Black Start Resource

A black start resource is a generating unit and its associated equipment that can be started without support from the power system, or is designed to remain energized without connection to the remainder of the power system. A black start resource needs to be able to energize a bus, meeting a system operator's restoration plan needs for real and reactive power capability, frequency, and voltage control. It must also be included in the transmission operator's restoration plan.

A black start resource must be capable of starting within 10 minutes. The starting sequence can be manual or automatic.

Primary Frequency Response

Primary frequency response is a generation resource's automatic response to an increase or decrease in frequency. The primary frequency response is the result of governor control, not control by AGC or frequency triggers, and must be sustainable. Unless controlled by a governor or droop response device, controlled load cannot provide primary frequency control.

The resource must immediately alter its output in direct proportion to the change in frequency, to counter the change in frequency. The response is determined by the design setting, which is specified by the system operator as a droop response from 1 to 5 percent. The response must be measurable within 10 seconds of the change in frequency. Under certain conditions, a certain generator resource may be placed on zero droop (also called isochronous control), such as under disturbance and restoration. Under these conditions, the isochronous generator will control system frequency instead of AGC.

Primary frequency response of a device is subject to the limitations of equipment. Equipment that is at its maximum operating output is not able to increase output in response to low frequency, but will still decrease its output in response to increasing frequency. Any generator at its maximum output, or a variable wind generator producing the maximum output for the available wind energy, may, if designed to have a frequency response, provide downward response to high frequency, but will not be able to increase output in response to low frequency. Curtailed variable generation or conventional generation operating below its maximum limit and above its minimum limit can contribute both upward and downward primary frequency response. Based on the design of its system, energy storage systems can also provide primary frequency response.

Primary frequency response cannot be withdrawn if frequency is within the bandwidth of a reportable disturbance as defined in BAL-HI-002. The primary frequency response should replace the inertia or fast frequency response of the system without a drop in system frequency.

Inertial or Fast Frequency Response

Inertial or fast frequency response is a local response to a change in frequency, reducing its rate of change. The response is immediate (measured in milliseconds), continuous, and proportional to the change in frequency, and does not rely on governor controls. The response is available even if the resource is also being used for other services (such as regulation or ramping). This response is short-lived, lasting not more than two to three seconds.

Inertial response relies on the rotating mass of a conventional generator. It can also be supplied by flywheels. Fast frequency response can be supplied by battery storage. If the inertia or fast response reserves are supplied from a resource that cannot sustain the load, primary or secondary resources must be available to take over without a drop in system frequency.

Secondary Frequency Control

Secondary (or supplemental) frequency control is provided by resources in response to AGC to correct a change in frequency, using both the regulating and contingency reserves. Secondary frequency response can be provided by conventional generation, load control, or variable generation, all of which must be under AGC control. If AGC is disabled, such as during system restoration, secondary frequency control will be provided by manual operation of resources to maintain the isochronous generator within its lower and upper limits. The response requirements for secondary control are the same as for participation in regulating reserves.

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F. Modeling Assumptions Data

The Hawaiian Electric Companies created this PSIP based, in parts, on a realization of the current state of the electric systems in Hawaiʻi, 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.

This appendix summarizes the assumptions utilized to perform the PSIP analyses.

Tables

UTILITY COST OF CAPITAL AND FINANCIAL ASSUMPTIONS

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

Table F-1 lists the various sources of capital, their weight (percent of the entire capital portfolio), and their individual rates of return. Composite percentages for costs of capital are presented under the table.

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

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

Table F-1. Utility Cost of Capital

FUEL SUPPLY AND PRICES FORECASTS

The potential cost of producing electricity will depend, in part, on the cost of fuels utilized in the generation of power. The cost of different fuels over the next 20-plus years are forecast and used in the PSIP analyses. The Companies burn the following different types of fuels:

- *No.2 Diesel Oil*
- *Low Sulfur Fuel Oil (LSFO)*. A residual fuel oil similar to No. 6 fuel oil that contains less than 5,000 parts per million of sulfur; about 0.5% sulfur content.
- *Ultra Low Sulfur Diesel (ULSD)*
- *Biodiesel*
- *Liquefied Natural Gas (LNG)* is a natural gas (a fossil fuel) that has been converted to a liquid, which sharply decreases volume and eases transportation and storage.

How the Fuel Price Forecasts Were Derived

Petroleum-Based Diesel Fuels

In general, we derived petroleum-based diesel fuels forecasts by applying the relationship between historical crude oil commodity prices and historical fuel purchase prices to forecasts for the crude oil commodity price. The petroleum-based fuel forecasts reflect U.S. Energy Information Administration (EIA) forecast data for *Imported Crude Oil* and *GDP Chain-Type Price Index* from the 2014 Annual Energy Outlook (AEO2014) year-by-year tables. Historical prices for crude oil are EIA publication table data for the *Monthly Energy Review* and macroeconomic data. Historical actual fuel costs incorporate taxes and certain fuel-related and fuel-handling costs including but not limited to trucking and ocean transport, petroleum inspection, and terminalling fees.

It may be necessary to utilize a fuel blend of LSFO and diesel oil (that is, 60% LSFO and 40% diesel) for purposes of environmental compliance.

Biodiesel

Biodiesel forecasts are generally derived by comparing commodity forecasts with recent biofuel contracts and RFP bids to determine adjustments needed to derive each company's respective biodiesel price forecast from forecasted commodities. EIA provides low, reference, and high petroleum forecasts, which are used to project low, reference, and high petroleum-based fuel price forecasts. A similar commodity forecast has not been found for biodiesel, although EIA might provide one in the future. In lieu of such a source, we used the Food and Agricultural Policy Research Institute at Iowa State University (FAPRI) to create a reference forecast, which we then scaled on the EIA Petroleum forecasts to create a low and high biodiesel forecast.

Liquefied Natural Gas (LNG)

We do not have historical purchase data for LNG in Hawai'i. For purposes of this PSIP analyses, LNG pricing (delivered to the power generation facilities) were developed as described in Appendix I: LNG to Hawai'i.

Hawaiian Electric Fuel Price Forecasts

$/MMBtu	Fuel Price Forecasts					
Year	*No.2 Diesel*	*LSFO*	*ULSD*	*40% Diesel/ 60% LSFO Blend*	*Biodiesel*	*LNG*
2014	$20.98	$18.27	$22.16	$19.32	$33.01	n/a
2015	$20.97	$18.23	$22.16	$19.29	$29.64	n/a
2016	$20.57	$17.81	$21.77	$18.88	$29.81	n/a
2017	$20.56	$17.76	$21.76	$18.84	$30.54	$15.71
2018	$21.01	$18.16	$22.23	$19.26	$31.21	$15.81
2019	$21.71	$18.82	$22.97	$19.94	$31.24	$16.00
2020	$22.51	$19.56	$23.79	$20.70	$31.30	$16.30
2021	$23.40	$20.39	$24.72	$21.55	$31.54	$16.69
2022	$24.33	$21.25	$25.68	$22.44	$31.92	$12.73
2023	$25.32	$22.18	$26.70	$23.39	$32.05	$12.95
2024	$26.30	$23.09	$27.72	$24.33	$32.54	$13.12
2025	$27.27	$23.99	$28.73	$25.26	$32.84	$13.33
2026	$28.18	$24.84	$29.68	$26.13	$33.14	$13.61
2027	$29.24	$25.82	$30.77	$27.14	$33.44	$14.02
2028	$30.23	$26.74	$31.79	$28.08	$33.74	$14.39
2029	$31.27	$27.70	$32.88	$29.08	$34.04	$14.78
2030	$32.26	$28.62	$33.91	$30.02	$34.34	$15.21

Table F-2. Fuel Price Forecasts

SALES AND PEAK FORECASTS

Sales and net peak forecasts were developed with and without the effects of Dynamic Pricing. As described in the *Integrated Demand Response Portfolio Plan (IDRPP)*[1] Dynamic Pricing is a demand response program that incent customers (on a voluntary basis) to change their energy use behavior, resulting is increased load demand during certain periods of the day and decreased net peak demand.

Sales Forecasts (without Dynamic Pricing Adjustments)

Year	Load without DG PV		Total DG PV (Uncurtailed)		Sales with DG PV
	Net Generation: GWh (a)	*Sales: Customer GWh (b)*	*Net GWh (c)*	*Customer GWh (d)*	*Customer GWh (b – d)*
2015	7,697.6	7,332.5	494.2	470.7	6,861.8
2016	7,831.1	7,459.7	571.6	544.4	6,915.2
2017	7,959.4	7,581.9	622.5	593.0	6,988.9
2018	8,002.1	7,622.5	655.9	624.8	6,997.7
2019	8,028.6	7,647.8	688.5	655.9	6,992.0
2020	8,048.3	7,666.6	725.1	690.7	6,975.9
2021	8,031.6	7,650.7	752.3	716.6	6,934.1
2022	8,010.7	7,630.8	782.6	745.5	6,885.3
2023	7,974.4	7,596.2	813.4	774.8	6,821.4
2024	7,917.0	7,541.5	846.8	806.7	6,734.8
2025	7,785.9	7,416.6	874.8	833.4	6,583.2
2026	7,584.6	7,224.9	904.9	862.0	6,362.9
2027	7,380.5	7,030.5	934.2	889.9	6,140.6
2028	7,176.4	6,836.1	965.4	919.6	5,916.5
2029	6,972.3	6,641.6	990.2	943.2	5,698.4
2030	6,768.2	6,447.2	1,016.6	968.3	5,478.9

Loss Factor: 4.743%

Table F-3. Sales Forecasts (without Dynamic Pricing Adjustments)

[1] The IDRPP was filed on July 28, 2014.

Sales Forecasts (with Dynamic Pricing Adjustments)

Year	Load without DG PV		Total DG PV (Uncurtailed)		Sales with DG PV
	Net Generation: GWh (a)	*Sales: Customer GWh (b)*	*Net GWh (c)*	*Customer GWh (d)*	*Customer GWh (b – d)*
2015	7,697.6	7,332.5	494.2	470.7	6,861.8
2016	7,829.8	7,458.4	571.6	544.4	6,914.0
2017	7,930.7	7,554.5	622.5	593.0	6,961.5
2018	7,973.5	7,595.3	655.9	624.8	6,970.5
2019	8,000.4	7,621.0	688.5	655.9	6,965.1
2020	8,020.3	7,639.9	725.1	690.7	6,949.2
2021	8,003.9	7,624.3	752.3	716.6	6,907.7
2022	7,983.6	7,604.9	782.6	745.5	6,859.4
2023	7,947.5	7,570.5	813.4	774.8	6,795.7
2024	7,889.9	7,515.7	846.8	806.7	6,709.0
2025	7,759.6	7,391.6	874.8	833.4	6,558.2
2026	7,559.4	7,200.8	904.9	862.0	6,338.9
2027	7,356.3	7,007.4	934.2	889.9	6,117.5
2028	7,153.4	6,814.1	965.4	919.6	5,894.6
2029	6,950.1	6,620.4	990.2	943.2	5,677.2
2030	6,747.1	6,427.1	1,016.6	968.3	5,458.7

Table F-4. Sales Forecasts (with Dynamic Pricing Adjustments)

Net Peak Forecasts

Year	Net Peak w/o Dynamic Pricing			Net Peak w/ Dynamic Pricing		
	Net Day Peak (w/o DG-PV)	Net Evening Peak (w/o DG-PV)	Total DG-PV	Net Day Peak (w/o DG-PV)	Net Evening Peak (w/o DG-PV)	Total DG-PV
	MW	*MW*	*MW*	*MW*	*MW*	*MW*
2015	1,187.0	1,195.0	325.7	1,187.0	1,195.0	325.7
2016	1,196.0	1,203.0	375.6	1,196.0	1,199.0	375.6
2017	1,215.0	1,223.0	410.3	1,223.0	1,137.0	410.3
2018	1,220.0	1,228.0	432.3	1,229.0	1,142.0	432.3
2019	1,230.0	1,238.0	453.8	1,238.0	1,151.0	453.8
2020	1,230.0	1,238.0	476.5	1,239.0	1,151.0	476.5
2021	1,220.0	1,227.0	495.8	1,230.0	1,141.0	495.8
2022	1,207.0	1,213.0	515.8	1,223.0	1,128.0	515.8
2023	1,194.0	1,200.0	536.1	1,203.0	1,117.0	536.1
2024	1,186.0	1,193.0	556.5	1,195.0	1,109.0	556.5
2025	1,154.0	1,160.0	576.6	1,165.0	1,082.0	576.6
2026	1,109.0	1,113.0	596.4	1,120.0	1,045.0	596.4
2027	1,063.0	1,066.0	615.7	1,075.0	1,009.0	615.7
2028	1,017.0	1,019.0	634.4	1,030.0	970.2	634.4
2029	970.7	972.0	652.6	983.9	931.1	652.6
2030	932.4	932.4	670.0	948.3	903.4	670.0

Table F-5. Net Peak Forecasts

DEMAND RESPONSE

Demand Response Programs

The *Integrated Demand Response Portfolio Plan*[2] introduced seven categories of programs.

Residential and Small Business Direct Load Control Program (RBDLC). This new RBDLC program continues and expands upon the existing RDLC and Small Business Direct Load Control (SBDLC) programs. RBDLC enables new and existing single-family, multi-family, and master metered residential customers, in addition to small businesses, to participate in an interruptible load program for electric water heaters, air conditioning, and other specific end uses.

Residential and Small Business Flexible Program. This new program enables residential and small business customers with targeted devices (such as controllable grid-interactive water heaters) to meet ancillary service requirements by providing adjustable load control and thermal energy storage features over various timeframes.

Commercial & Industrial Direct Load Control Program (CIDLC). The updated CIDLC program allows commercial and industrial customers to help shift load, usually during peak periods, by allowing their central air conditioning, electric water heaters, and other applicable appliances to be remotely cycled or disconnected.

Commercial & Industrial Flexible Program. This new program enables commercial and industrial customers with targeted devices (such as air conditioning, ventilation, refrigeration, water heating, and lighting) to meet ancillary service requirements by providing adjustable load control and/or thermal energy storage features over differing timeframes.

Commercial & Industrial Pumping Program. The Commercial & Industrial Pumping program enables county and privately owned water facilities with pumping loads and water storage capabilities to be dynamically controlled. This will be accomplished by using variable frequency drives and emergency standby generation to adjust power demand and supply at the water facilities, and better balance supply and demand of power system loads.

Customer Firm Generation Program. Commercial and industrial customers who participate in this program allow system operators to dispatch their on-site standby generators to help meet power system load demand. Monitoring equipment on the

[2] *ibid.*

standby generators tracks the usage of program participation, testing, and assures environmental permit compliance.

Dynamic & Critical Peak Pricing program. This program enables load shifting to "smooth" the daily system load profiles based on demand and price.

Cost of DR Programs

Several grid services foretell the cost of the demand response programs. The avoided cost for a grid service is the cost of an alternative resource (energy storage or a generator) providing the equivalent service. Avoided cost could be based on several factors, including installed capacity costs, fuel costs, and cost of alternatives, each of which depends on the current state of the system. Potential avoided cost calculations include:

Capacity: The cost of new capacity deferral.

Regulating Reserve: The cost of a frequency support energy storage device, or the savings from reduced regulating reserve requirements, as calculated using a production cost model.

Contingency Reserve:. For O'ahu, the fuel cost savings resulting from a reduction in the contingency reserve requirement from thermal generation commensurate with the DR resources assumed to meet the contingency reserve requirements, as calculated using a production cost model. For Maui and Hawai'i, this would offset under-frequency load shedding, which potentially provides a customer benefit but not a readily evaluated economic benefit.

Non-AGC Ramping: The fuel cost and maintenance savings resulting from deferring the start of units to compensate for variable energy down ramps.

Non-Spinning Reserve: The cost of maintaining existing resources that currently meet non-spinning reserves (small diesel units).

Advanced Energy Delivery: The production cost savings incurred by shifting demand, as compared to production costs if demand were not shifted.

All of the above avoided costs are offset by the program costs and reduced sales. Where a resource or program can meet two or more grid service requirements, although not simultaneously, the avoided cost is determined by the most economic use. The maximum price paid for a DR program would be the difference between the avoided cost and the program's operational cost. At the maximum price, the overall rate impact to customers would be economically neutral.

DR Grid Service Requirements and MW Benefits

Grid Service	Residential and Small Business Direct Load Control[3]				Residential and Small Business Flexible	
	Capacity	*Contingency Reserve*	*Non-AGC Ramping*	*Non-Spinning Reserve*	*Regulating Reserve*	*Accelerated Energy Delivery*
Frequency	Unlimited	Unlimited	Unlimited	Unlimited	Continuous	Continuous
Event Length	1 hour	1 hour	1 hour	1 hour	Minutes	Minutes
Event Cost	None	None	None	None	None	None
Year	*MW*	*MW*	*MW*	*MW*	*MW*	*MW*
2014	16.0	0.0	16.0	16.0	0.0	0.0
2015	18.9	0.0	18.9	18.9	0.6	0.3
2016	21.8	0.0	21.8	21.8	1.3	0.7
2017	24.7	0.0	24.7	24.7	1.9	1.0
2018	27.5	0.0	27.5	27.5	2.6	1.4
2019	30.4	0.0	30.4	30.4	3.3	1.7
2020	33.3	0.0	33.3	33.3	3.9	2.1
2021	33.3	0.0	33.3	33.3	4.5	2.4
2022	33.3	0.0	33.3	33.3	5.1	2.7
2023	33.3	0.0	33.3	33.3	5.1	2.7
2024	33.3	0.0	33.3	33.3	5.1	2.7
2025	33.3	0.0	33.3	33.3	5.1	2.7
2026	33.3	0.0	33.3	33.3	5.1	2.7
2027	33.3	0.0	33.3	33.3	5.1	2.7
2028	33.3	0.0	33.3	33.3	5.1	2.7
2029	33.3	0.0	33.3	33.3	5.1	2.7
2030	33.3	0.0	33.3	33.3	5.1	2.7

Table F-6. Demand Response Program Grid Service Requirements and MW Benefits (1 of 2)

[3] The 2014 figure of 16.0 MW is the long standing planning assumption derived from the per device assumptions in the 2011 EnergyScout Impact Evaluation study. The IDRPP filed on July 28 reflects a lower figure of 10 MW, based on the average curtailment results from 2013 events conducted during evening peak hours."

Grid Service	Commercial & Industrial Direct Load Control		Commercial & Industrial Flexible		Commercial & Industrial Pumping		Customer Firm Generation
	Capacity	*Contingency Reserve*	*Regulating Reserve*	*Non-AGC Ramping*	*Regulating Reserve*	*Non-AGC Ramping*	*Capacity*
Frequency	300 hours per year	300 hours per year	Continuous	Continuous	Continuous	Continuous	100 hours per year
Event Length	4 hours maximum	4 hours maximum	Minutes	Minutes	Minutes	Minutes	4 hours maximum
Event Cost	50¢/kWh	50¢/kWh	None	None	None	None	50¢/kWh
Year	*MW*	*MW*	*MW*	*MW*	*MW*	*MW*	*MW*
2014	16.0	0.0	0.0	0.0	0.0	0.0	0.0
2015	17.6	0.0	0.5	1.7	0.2	0.2	0.0
2016	19.1	0.0	1.0	3.5	0.5	0.5	5.0
2017	20.7	0.0	1.6	5.3	0.7	0.7	5.0
2018	22.3	0.0	2.1	7.1	0.9	0.9	5.0
2019	23.8	0.0	2.6	9.0	1.2	1.2	5.0
2020	25.4	0.0	3.2	10.8	1.4	1.4	5.0
2021	25.4	0.0	3.7	12.5	1.7	1.7	5.0
2022	25.4	0.0	4.1	14.1	1.9	1.9	5.0
2023	25.4	0.0	4.1	14.1	1.9	1.9	5.0
2024	25.4	0.0	4.1	14.1	1.9	1.9	5.0
2025	25.4	0.0	4.1	14.1	1.9	1.9	5.0
2026	25.4	0.0	4.1	14.1	1.9	1.9	5.0
2027	25.4	0.0	4.1	14.1	1.9	1.9	5.0
2028	25.4	0.0	4.1	14.1	1.9	1.9	5.0
2029	25.4	0.0	4.1	14.1	1.9	1.9	5.0
2030	25.4	0.0	4.1	14.1	1.9	1.9	5.0

Table F-7. Demand Response Program Grid Service Requirements and MW Benefits (2 of 2)

RESOURCE CAPITAL COSTS[4]

Table F-9 through Table F-16 show the calculations to arrive at the capital cost for various resources used in the PSIP modeling analyses. The overall cost escalation rate used in our analyses is 1.83%.

Table Legend

Column Heading	Explanation
NREL Capital Cost, 2009 $, $/kW	The starting basis for capital costs used in the analyses unless noted otherwise
B&V Hawai'i Capital Cost, 2009 $, $/kW	The starting basis for capital cost of the ICE (<100 MW)
BCG Capital Cost, 2009 $, $/kW	The starting basis for capital cost of the ICE (>100 MW)
EIA Capital Cost, 2009 $, $/kW	The starting basis for capital cost of the Waste-to-Energy resource
Capital Cost, Nominal $, $/kW	An escalated capital cost of the resource from 2009 dollars up to the year of installation
EIA Adjustment Factor	A location specific cost adjustment factor for Hawai'i
Utility Adjustment Factor	A technology specific cost adjustment factor
Adjusted Capital Cost, Nominal $, $/kW	An escalated capital cost of the resource that reflects any cost adjustment factors
NREL Fixed O&M, 2009 $, $/kW-year	The starting basis for fixed O&M used in the analyses
Fixed O&M, Nominal $, $/kW	An escalated fixed O&M cost of the resource from 2009 dollars up to the year of installation
NREL Variable O&M, 2009 $, $/MWh	The starting basis for variable O&M used in the analyses
Variable O&M, Nominal $, $/MWh	An escalated variable O&M cost of the resource from 2009 dollars up to the year of installation

Table F-8. Resource Capital Cost Table Legend

[4] Calculations were based on *Cost and Performance Data for Power Generation Technologies*, prepared for the National Renewable Energy Laboratory (NREL), Black & Veatch, February 2012.

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Simple Cycle Large (40–100 MW) Aeroderivative Combustion Turbine

Year Installed	NREL Capital Cost, 2009 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$651.00	$726.04	51.5%	1.46	$1,608.29	$5.26	$5.87	$29.90	$33.35
2020	$651.00	$795.14	51.5%	1.46	$1,761.36	$5.26	$6.42	$29.90	$36.52
2025	$651.00	$870.81	51.5%	1.46	$1,928.99	$5.26	$7.04	$29.90	$40.00
2030	$651.00	$953.69	51.5%	1.46	$2,112.58	$5.26	$7.71	$29.90	$43.80

Table F-9. Simple Cycle Large (40–100 MW) Aeroderivative Combustion Turbine

Simple Cycle Small (<40 MW) Aeroderivative Combustion Turbine

Year Installed	NREL Capital Cost, 2009 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$651.00	$726.04	51.5%	1.77	$1,945.73	$5.26	$5.87	$29.90	$33.35
2020	$651.00	$795.14	51.5%	1.77	$2,130.91	$5.26	$6.42	$29.90	$36.52
2025	$651.00	$870.81	51.5%	1.77	$2,333.71	$5.26	$7.04	$29.90	$40.00
2030	$651.00	$953.69	51.5%	1.77	$2,555.82	$5.26	$7.71	$29.90	$43.80

Table F-10. Simple Cycle Small (<40 MW) Aeroderivative Combustion Turbine

Internal Combustion (<100 MW) Engine

Year Installed	B&V Hawai'i Capital Cost, 2012 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$2,810.00	$2,967.54	0.0%	1.00	$2,967.54	$10.14	$11.31	$11.74	$13.09
2020	$2,810.00	$3,249.96	0.0%	1.00	$3,249.96	$10.14	$12.39	$11.74	$14.34
2025	$2,810.00	$3,559.27	0.0%	1.00	$3,559.27	$10.14	$13.56	$11.74	$15.70
2030	$2,810.00	$3,898.02	0.0%	1.00	$3,898.02	$10.14	$14.85	$11.74	$17.20

Table F-11. Internal Combustion (<100 MW) Engine

Internal Combustion (>100 MW) Engine

Year Installed	BCG Capital Cost, 2012 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$1,352.00	$1,427.80	0.0%	1.20	$1,713.36	$10.14	$11.31	$11.74	$13.09
2020	$1,352.00	$1,563.68	0.0%	1.20	$1,876.42	$10.14	$12.39	$11.74	$14.34
2025	$1,352.00	$1,712.50	0.0%	1.20	$2,055.01	$10.14	$13.56	$11.74	$15.70
2030	$1,352.00	$1,875.49	0.0%	1.20	$2,250.59	$10.14	$14.85	$11.74	$17.20

Table F-12. Internal Combustion (>100 MW) Engine

Residential Photovoltaics

Year Installed	NREL Capital Cost, 2009 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$4,340.00	$4,840.26	0.0%	1.00	$4,840.26	$48.00	$53.53	$0.00	$0.00
2020	$3,750.00	$4,580.29	0.0%	1.00	$4,580.29	$45.00	$54.96	$0.00	$0.00
2025	$3,460.00	$4,628.29	0.0%	1.00	$4,628.29	$43.00	$57.52	$0.00	$0.00
2030	$3,290.00	$4,819.74	0.0%	1.00	$4,819.74	$41.00	$60.06	$0.00	$0.00

Table F-13. Residential Photovoltaics

Utility Scale Photovoltaics (Fixed Tilt)

Year Installed	NREL Capital Cost, 2009 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$2,550.00	$2,843.93	0.0%	0.75	$2,132.95	$48.00	$53.53	$0.00	$0.00
2020	$2,410.00	$2,943.60	0.0%	0.75	$2,207.70	$45.00	$54.96	$0.00	$0.00
2025	$2,280.00	$3,049.86	0.0%	0.75	$2,287.39	$43.00	$57.52	$0.00	$0.00
2030	$2,180.00	$3,193.62	0.0%	0.75	$2,395.22	$41.00	$60.06	$0.00	$0.00

Table F-14. Utility Scale Photovoltaics (Fixed Tilt)

Geothermal, Non-Dispatchable

Year Installed	NREL Capital Cost, 2009 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$5,940.00	$6,624.69	27.2%	1.00	$8,426.61	$36.00	$40.15	$31.00	$34.57
2020	$5,940.00	$7,255.18	27.2%	1.00	$9,228.59	$36.00	$43.97	$31.00	$37.86
2025	$5,940.00	$7,945.68	27.2%	1.00	$10,106.91	$36.00	$48.16	$31.00	$41.47
2030	$5,940.00	$8,701.89	27.2%	1.00	$11,068.81	$36.00	$52.74	$31.00	$45.41

Table F-15. Geothermal, Non-Dispatchable

Geothermal, Fully Dispatchable

Year Installed	NREL Capital Cost, 2009 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$6,065.00	$6,764.10	27.2%	1.00	$8,603.94	$36.00	$40.15	$31.00	$34.57
2020	$6,065.00	$7,407.86	27.2%	1.00	$9,422.80	$36.00	$43.97	$31.00	$37.86
2025	$6,065.00	$8,112.89	27.2%	1.00	$10,319.59	$36.00	$48.16	$31.00	$41.47
2030	$6,065.00	$8,885.02	27.2%	1.00	$11,301.74	$36.00	$52.74	$31.00	$45.41

Table F-16. Geothermal, Fully Dispatchable

Combined Cycle Turbine

Year Installed	NREL Capital Cost, 2009 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$1,230.00	$1,371.78	53.1%	1.21	$2,533.86	$6.31	$7.04	$3.67	$4.09
2020	$1,230.00	$1,502.34	53.1%	1.21	$2,775.02	$6.31	$7.71	$3.67	$4.48
2025	$1,230.00	$1,645.32	53.1%	1.21	$3,039.13	$6.31	$8.44	$3.67	$4.91
2030	$1,230.00	$1,801.91	53.1%	1.21	$3,328.37	$6.31	$9.24	$3.67	$5.38

Table F-17. Combined Cycle Turbine

Run-of-River Hydroelectric

Year Installed	NREL Capital Cost, 2009 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$3,500.00	$3,903.44	19.1%	1.35	$6,276.14	$15.00	$16.73	$24.00	$26.77
2020	$3,500.00	$4,274.94	19.1%	1.35	$6,873.46	$15.00	$18.32	$24.00	$29.31
2025	$3,500.00	$4,681.80	19.1%	1.35	$7,527.63	$15.00	$20.06	$24.00	$32.10
2030	$3,500.00	$5,127.38	19.1%	1.35	$8,244.06	$15.00	$21.97	$24.00	$35.16

Table F-18. Run-of-River Hydroelectric

Wind, Onshore

Year Installed	NREL Capital Cost, 2009 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$1,980.00	$2,208.23	30.1%	1.00	$2,872.91	$60.00	$66.92	$0.00	$0.00
2020	$1,980.00	$2,418.39	30.1%	1.00	$3,146.33	$60.00	$73.28	$0.00	$0.00
2025	$1,980.00	$2,648.56	30.1%	1.00	$3,445.78	$60.00	$80.26	$0.00	$0.00
2030	$1,980.00	$2,900.63	30.1%	1.00	$3,773.72	$60.00	$87.90	$0.00	$0.00

Table F-19. Wind, Onshore

Wind, Offshore (Floating Platform)

Year Installed	NREL Capital Cost, 2009 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	Not Commercial	Not Commercial	0.0%	Not Commercial	$0.00	$0.00	$0.00	$0.00	Not Commercial
2020	$4,200.00	$5,129.93	30.1%	1.00	$6,674.04	$130.00	$158.78	$0.00	$0.00
2025	$4,090.00	$5,471.02	30.1%	1.00	$7,117.79	$130.00	$173.90	$0.00	$0.00
2030	$3,990.00	$5,845.21	30.1%	1.00	$7,604.62	$130.00	$190.45	$0.00	$0.00

Table F-20. Wind, Offshore (Floating Platform)

Waste-to-Energy

Year Installed	EIA Capital Cost, 2009 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$8,312.00	$8,777.99	19.6%	1.00	$10,498.48	$392.82	$414.84	$8.75	$9.24
2020	$8,312.00	$9,613.42	19.6%	1.00	$11,497.65	$392.82	$454.32	$8.75	$10.12
2025	$8,312.00	$10,528.36	19.6%	1.00	$12,591.91	$392.82	$497.56	$8.75	$11.08
2030	$8,312.00	$11,530.37	19.6%	1.00	$13,790.32	$392.82	$544.92	$8.75	$12.14

Table F-21. Waste-to-Energy

Biomass Steam

Year Installed	NREL Capital Cost, 2009 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$3,830.00	$4,271.48	53.6%	1.00	$6,560.99	$95.00	$105.95	$15.00	$16.73
2020	$3,830.00	$4,678.01	53.6%	1.00	$7,185.42	$95.00	$116.03	$15.00	$18.32
2025	$3,830.00	$5,123.23	53.6%	1.00	$7,869.27	$95.00	$127.08	$15.00	$20.06
2030	$3,830.00	$5,610.82	53.6%	1.00	$8,618.22	$95.00	$139.17	$15.00	$21.97

Table F-22. Biomass Steam

Ocean Wave

Year Installed	NREL Capital Cost, 2009 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$9,240.00	$10,305.08	13.8%	1.00	$11,727.18	$474.00	$528.64	$0.00	$0.00
2020	$6,960.00	$8,501.02	13.8%	1.00	$9,674.16	$357.00	$436.04	$0.00	$0.00
2025	$5,700.00	$7,624.64	13.8%	1.00	$8,676.84	$292.00	$390.60	$0.00	$0.00
2030	$4,730.00	$6,929.29	13.8%	1.00	$7,885.53	$243.00	$355.99	$0.00	$0.00

Table F-23. Ocean Wave

G. Generation Resources

Electricity is typically produced through a turbine-generator process. The turbine rotates and drives a shaft in the generator to create electrical current.

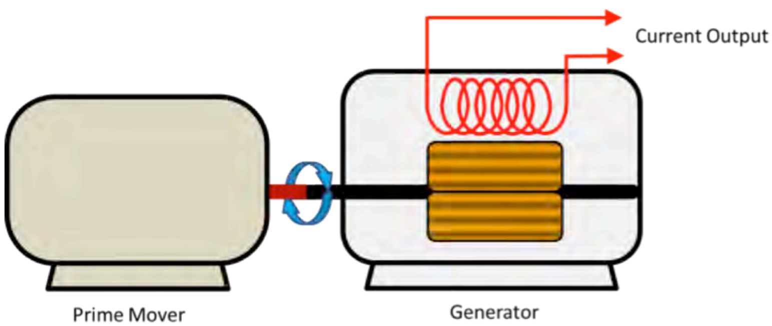

Figure G-1. Turbine-Generator Process

Turbines can be powered by different variable and firm sources. Variable energy is unpredictable because its energy source cannot be scheduled nor can it be controlled. Firm energy can be predicted, scheduled, dispatched, and controlled.

VARIABLE RNEWABLE ENERGY RESOURCES

Several variable renewable energy resources were considered in our PSIP analysis, all of which are currently in our generation mix. This type of energy is variable because its primary energy sources (such as wind, sun, and water) cannot be predicted.

The capacity value (essentially the percent of its "nameplate" generating amount that is available to the grid) of variable renewable energy varies by each resource, and is typically a small percentage of the nameplate value or zero. In addition, because the generation from variable renewable energy cannot be scheduled, it cannot be dispatched; in other words, it cannot be used to help regulate the balance between supply and demand.

Wind

Wind energy generation is the conversion of the wind's kinetic energy into electricity. Wind generating facilities are best located where wind is persistently steady. On Hawai'i with its terrain of hills, valleys, and ridges, variations in siting can have profound effects on the strength and quantity of wind currents.

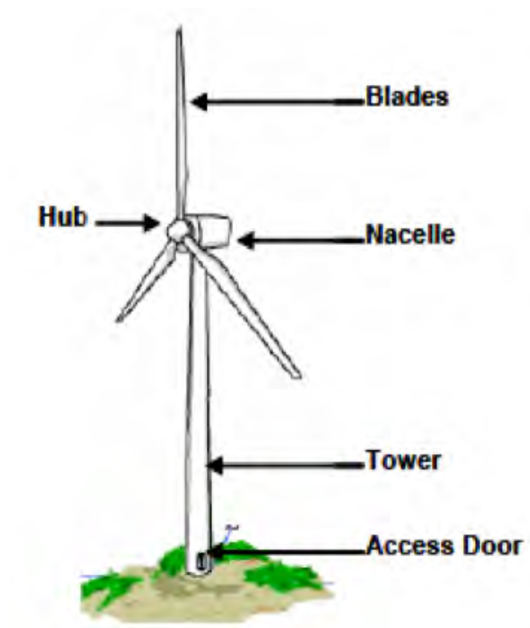

Figure G-2. Wind Turbine and Tower

As the wind turns a wind turbine's blades, the main shaft in the turbine rotates which in turn drives a generator (situated in the nacelle) to produce electricity. The annual capacity factor[1] of wind is generally about 25% at locations throughout Hawai'i, although it can attain a capacity factor of more than 50%.

A wind turbine shuts down when the wind is either too slow or too fast. The size of the wind turbine is generally in direct proportion to how much electricity can be generated. Larger wind turbines generate more power, while smaller turbines generate less. Thus, wind is a variable, non-dispatchable energy source.

[1] The Annual Capacity Factor, expressed in percent, is the amount of energy produced in a year compared to the amount of energy potentially produced by the facility if it was operated at 100% of its rated capacity for 100% of the time in the year.

Solar Photovoltaics

Solar photovoltaic energy is generated from its cells, and not by turning a turbine. Photovoltaic (PV) cells are made of semiconductors (such as silicon). When light strikes the cell, a certain portion of it is absorbed within the semiconductor material. The energy of the absorbed light is transferred to the semiconductor. The energy knocks electrons loose, allowing them to flow freely. This flow of electrons is a current, and by placing metal contacts on the top and bottom of the cell, this electric current can be drawn off for external use. The most common solar cell material is crystalline silicon, but newer materials for making solar cells include thin-film materials.

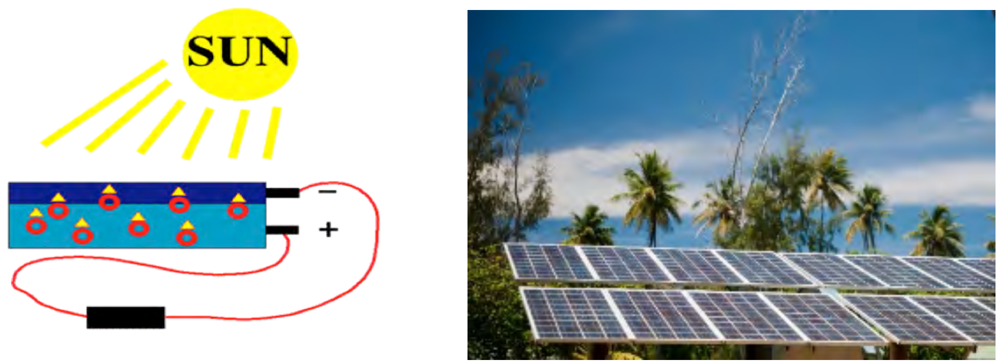

Figure G-3. Schematic of a Photovoltaic (PV) Cell and an Array of PV Panels

Solar PV is a variable renewable energy resource that cannot be scheduled and dispatched. Its annual capacity factor hovers between 18% to 22%. Solar PV only generates power when the sun is out and not blocked by clouds. On cloudless days, solar power gradually increases as the sun rises in the morning, peaks around 2 PM, and then gradually decreases until the sun sets. If at any point during the day a cloud blocks the sun, power output drops suddenly only to jump back up when the cloud passes. Thus, solar PV power generation can be erratic.

While solar PV systems can be made a few different ways, the most predominant is framed panels (as shown in Figure G-3). These panels consist of PV cells packaged as modules and framed into panels using aluminum framing, wiring, and glass enclosures. Multiple panels can be assembled into larger systems as arrays.

Distributed Solar Generation (DG-PV). These arrays can be installed on building rooftops, typically in a fixed direction as illustrated in Figure G-4. This rooftop solar is referred to as distributed generation because of the numerous small PV systems installed in many different locations distributed throughout the grid. These rooftop PV panels produce direct current (DC) electricity fed to an inverter which converts the electricity to alternating current (AC) for use by the building or home. Surplus PV electricity—more than the building can use—flows into the electric power grid.

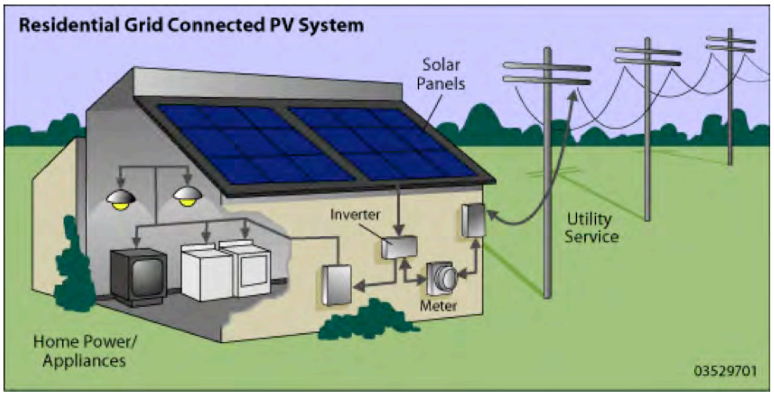

Figure G-4. Residential Distributed Generation PV System

Utility-Scale Solar PV. The PV panel arrays can also be mounted in large-scale ground mounted PV generating facilities (also referred to as "solar farms") that sometimes use tracking systems to actively tilt the PV panels towards the sun as it moves across the sky, thus increasing the annual capacity factor. These panels also produce direct current (DC) electricity. Inverters convert the electricity to alternating current (AC) where it immediately flows into the electric power grid.

Run-Of-River Hydroelectric

Hydropower is power derived from the energy of falling or moving water, which may be harnessed for useful purposes. Since ancient times, hydropower has been used to irrigate and operate various mechanical devices, such as watermills, sawmills, textile mills, dock cranes, and domestic lifts.

For run-of-the-river hydro projects, a portion of a river's water is diverted to a channel, pipeline, or pressurized pipeline (penstock) that delivers it to a waterwheel or turbine. If the river is not flowing, the hydroelectric facility produces no power. The moving water rotates the wheel or turbine, which spins a shaft. The motion of the shaft can be used for mechanical processes (such as pumping water) or it can power a turbine-generator to generate electricity.

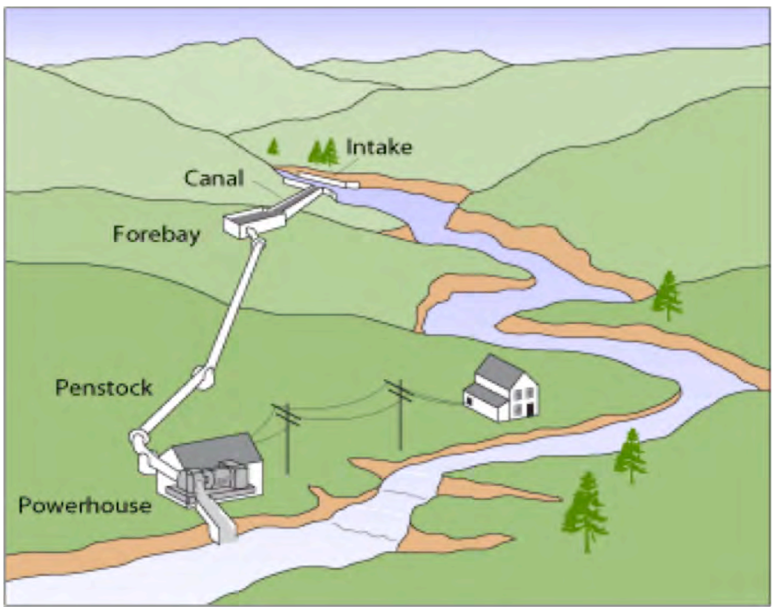

Figure G-5. Run-of-River Hydroelectric Plant

The primary development considerations are finding sites with adequate water flow and pressure, which are located in reasonable proximity to the electric grid for interconnection.

Energy Storage in Combination with Variable Renewable Energy

Wind, solar, and hydroelectric are all variable renewable energy sources. As such, they cannot be used to maintain the stability of an electric power grid, that delicate balance between supply and demand. Energy storage, however, can alleviate this situation and help provide more reliable energy, or in some cases, firm renewable power.

Energy storage can capture excess variable energy—generation that is not currently needed to meet demand—and store it in other forms until needed. This stored energy can later be converted back to its electrical form and returned to the grid as needed. Stored in high enough amounts, these sources could then be treated as firm power than may be scheduled and dispatched. (See Appendix J: Energy Storage Plan for more details.)

Pumped-storage hydroelectricity is a type of hydroelectric energy that includes energy storage. Water is pumped from a lower elevation to a higher elevation, where the stored water can be subsequently released through turbines to produce electricity. Electricity for pumping the water would typically occur during off-peak periods when the cost is low, or when during periods when there is excess energy generation from variable renewable resources. The generated electricity is then used during on-peak periods when demand is higher.

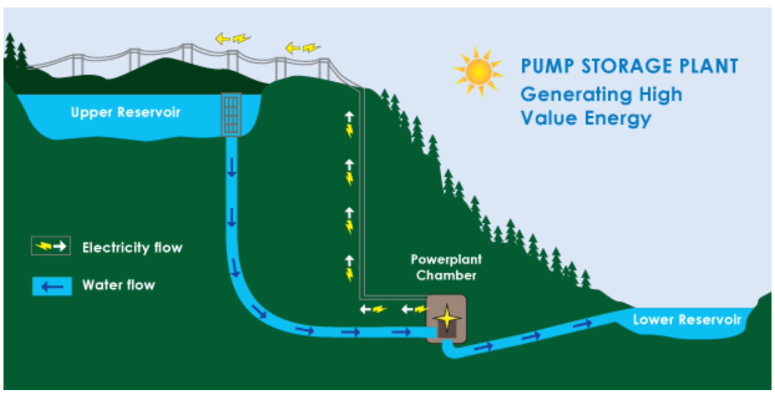

Figure G-6. Pumped Storage Hydroelectricity Plant

FIRM GENERATION

Several types of firm generation are included in our PSIP analysis, many of which are currently in our generation mix. Firm generation is predictable because its energy source (both fossil fuels and renewable fuels) can be scheduled, dispatched, and controlled.

The annual capacity value of firm generation can also be managed. A firm generation source can be operated as much or as little as necessary to meet demand. As such, firm generation is dispatchable; in other words, it can be used to help regulate the balance between supply and demand.

Gas Turbine Engine (or Combustion Turbine)

A gas turbine engine rotates as a result of hot gases (the product of the combustion of fuels) traveling through sets of turbine blades. As illustrated in Figure G-7, the flames themselves do not touch the turbine blades – just the gases produced by the flames. The combustor is where the fuel and air are mixed to enable the combustion process to occur. The fuel for this type of prime mover is either gas or liquid (not coal or biomass).

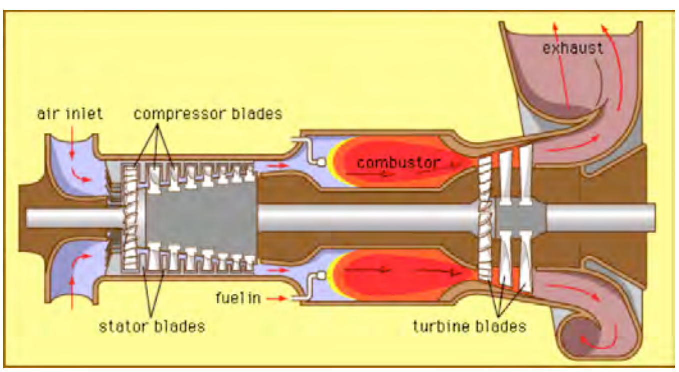

Figure G-7. Gas Turbine Engine

There are two types of gas turbines used for power generation: Aeroderivative and Frame.

Aeroderivative. This class of turbine is smaller (up to 100 MW) and can be quickly started and ramped, which makes them more compatible with grids that have large amounts of variable generation.

Frame. This type of turbine is generally larger (up to 340 MW), but not as fast reacting for both starting and ramping.

Gas turbines produce firm, dispatchable generation.

Steam Turbine: Combined Cycle and Boilers

A steam turbine operates by high pressure steam traveling through the turbine blades, causing the turbine shaft to rotate. This high pressure steam can be produced by a variety of technologies including Heat Recovery Steam Generators (HRSG) and fuel-fired boilers. All steam turbines produce firm, dispatchable generation.

Heat Recovery Steam Generators (HRSG)

HRSG use the high temperature exhaust gas from gas turbines engines to create steam for use in a steam turbine generator. This allows more electricity to be produced without using any additional fuel. The assembly of gas turbine, HRSG, and other auxiliary equipment used is referred to as combined cycle.

Hot combustion gases travel across the gas turbine blades to make the turbine spin where these gases are released at high temperature. A HRSG connects to the end of the gas turbine to take advantage of the energy that remains in the hot exhaust gases. The heat from these hot exhaust gases turns water contained in the HRSG into steam, where it is then sent to a steam turbine causing its connected generator to spin, thus producing electricity. Used steam is then converted back into water and reused again in the HRSG.

As illustrated in Figure G-8, combined cycle turbines can be either "single-train" (that is, one gas turbine and HRSG tied to the steam turbine) or "dual-train" two gas turbines and HRSG assemblies tied to a single steam turbine).

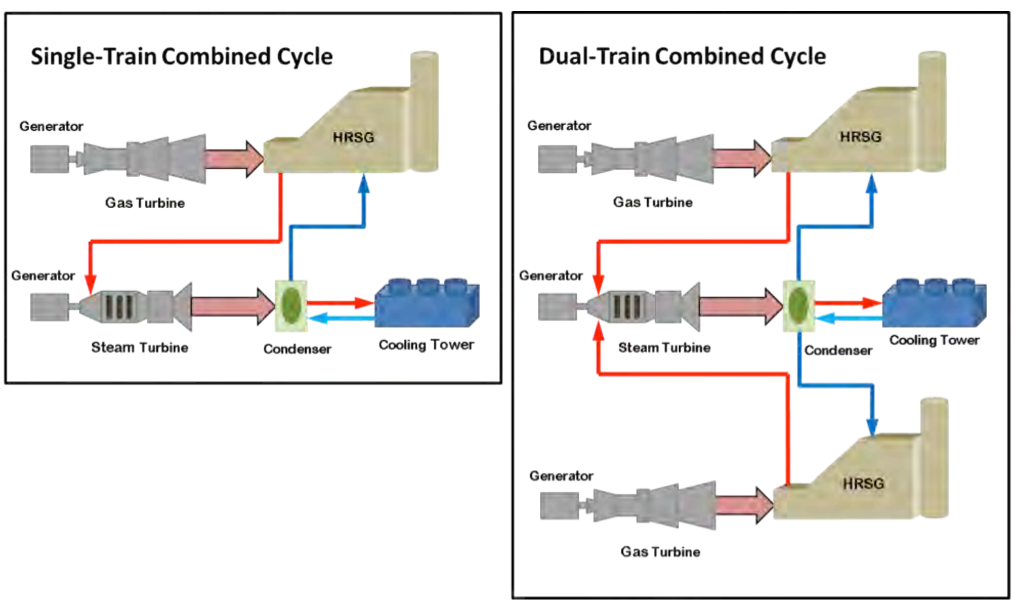

Figure G-8. Combined Cycle Plant: Single-Train and Dual-Train

A dual-train configuration provides twice as much power at a lower cost as a similar sized single-train configuration.

Reciprocating Internal Combustion Engine (RICE) or "Diesel Engine"

The type of reciprocating internal combustion engine used to produce electricity is a diesel engine. These engines can burn a variety of fuels, including diesel, biodiesel, biocrude, heavy oil, natural gas, and biogas. Diesel engines start and ramp quickly. Diesel engines produce firm, dispatchable generation.

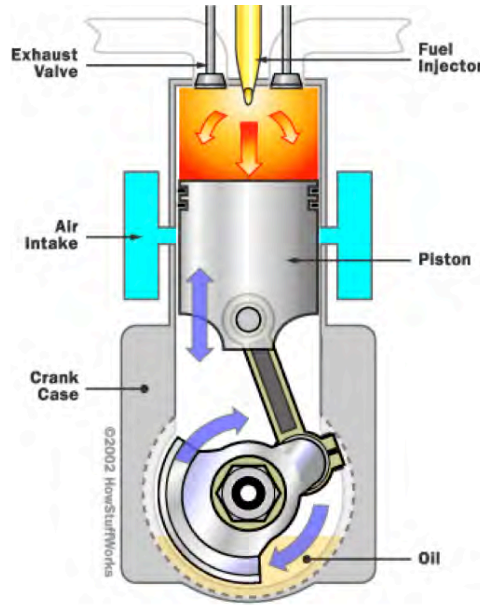

Figure G-9. Diesel Engine

Diesel engines have many combustion chambers called cylinders, each of which drives a piston connected to a common rotating shaft. This shaft is coupled to the generator to make it rotate. The number and size of these cylinders (illustrated as orange in the picture below) determine how much electrical output the engine can produce.

Diesel engine ratings can range from a few kW up to about 18MW. Larger diesel engines, because of their design, preclude them from meeting US Environmental Protection Agency (EPA) air emission limits. In addition, the EPA has different air regulations for diesel engines depending on the size of the cylinders.

Boilers (or Steam Generators)

A boiler furnace is made up primarily of small diameter (about 2-inch) metal tubes welded side by side to make a rectangular box. The tubes, which contain high purity water, are connected to a steam drum. The large fire inside the furnace transmits heat to the water inside the tubes to create steam in the steam drum. Fuel and air are continually added to the furnace to feed the fire.

Steam leaves the steam drum and travels through an independent set of tubes where it is heated to its final temperature by hot combustion exhaust gases. The steam then moves into the steam turbine, causing them to rotate and thus generate electricity. Boilers use a variety of fuels, including coal, biomass, liquid fuel oil, gas, and garbage.

Boilers come in many types, shapes, and sizes. Figure G-10 shows a simplified boiler steam turbine power plant. The boiler itself is outlined in the dotted red box.

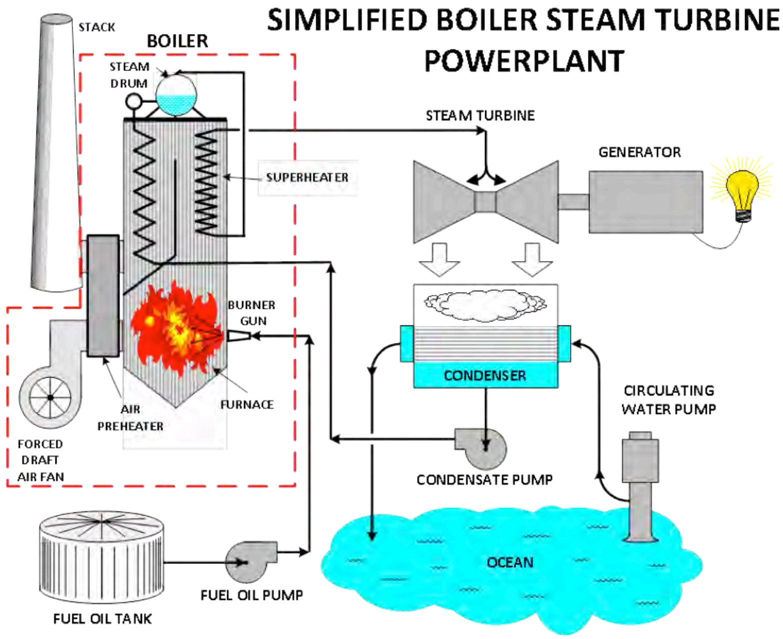

Figure G-10. Simplified Boiler Steam Turbine

Used steam can be converted back into water and reused in the boiler. A condenser forces the steam to travel over metal tubes that contain cold seawater, which causes the steam to turn back into water where it is pumped back into the steam drum, where the generation process begins again.

Renewable Fuel for Boilers–Waste (or Garbage)

Waste-to-energy is a renewable fuel-fired steam-electric power plant in which waste (or garbage) is burned in whole or in part as an alternative to fossil fuels. Paper, organics, and plastic wastes account for the largest share of solid waste used for the waste-to-energy stream. Incinerating solid waste to generate electricity is one method to reduce this waste volume. The fractions of solid waste—paper, wood waste, food waste, yard waste—are forms of a biomass fuel. Americans generate approximately 4.5 pounds of garbage per day. In Hawaiʻi, solid waste consists primarily of 30% paper, 25% other organics, and 12% plastics with the remainder comprised of metals, glass, and other materials.

Solid waste is mechanically processed in a "front end" system to produce a more homogenous fuel called refuse-derived fuel (RDF). RDF, in its simplest form, is shredded solid waste with the metals removed. This RDF must be processed further to remove other non-combustible materials such as glass, rocks, non-burnables, and aluminum.

Additional screening and shredding stages can be done to further enhance the RDF. The RDF is then fired in the boiler to produce steam that is directed to a turbine or generator.

In general, a robust waste-to-energy generation reduces the amount of landfill refuse by 90%.

Renewable Fuel for Boilers–Biomass

Biomass is another renewable fuel that can be used in boilers as alternatives to fossil fuels such as liquefied natural gas (LNG), oil, and coal.

Biomass is commonly defined as material derived from living organic matter (for example, trees, grasses, animal manure). Biomass includes wood and wood waste, herbaceous crops and crop wastes, food processing wastes such as bagasse, animal manures, and miscellaneous related materials. Biomass can be grown for the purpose of power generation from numerous types of plants, including switchgrass, hemp, corn, poplar, willow, sorghum, sugarcane, and a variety of trees such as eucalyptus and palm.

Biomass can either be burned directly to produce steam to make electricity, or processed into other energy products such as liquid or gaseous biofuel. In general, generating electricity directly from biomass is more efficient than converting it to biofuel. Siting a power generation facility at the source of the biomass, however, is not always feasible. Biofuel's transportability offers an attractive advantage.

Figure G-11 shows a process for converting wood waste into a biogas, which is then burned to create steam to generate electricity.

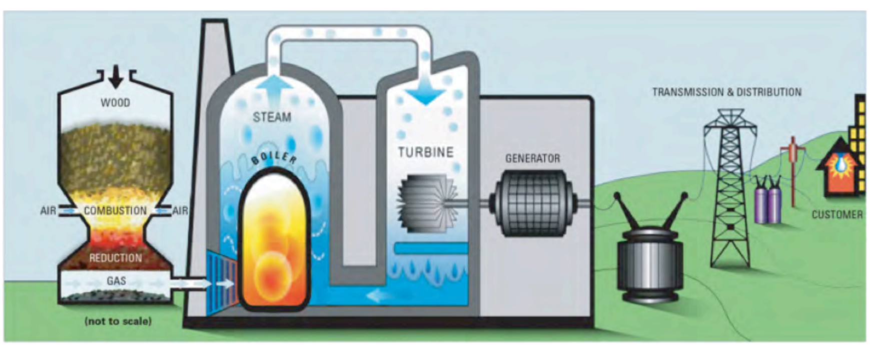

Figure G-11. Biomass Gasification

Aside from their fuel coming from renewable biomass, the power generation components of these facilities are similar to conventional power plants. In many cases, the power plants burn a combination of biofuel and fossil fuel.

Geothermal

Geothermal energy is heat energy from the earth. A layer of hot and molten rock called magma lies below the earth's crust. Heated ground water exposed to this magma can be extracted to provide geothermal energy at the surface. Resources of geothermal energy range from the shallow ground to hot water and hot rock found a few miles beneath the earth's surface where the earth's crust is thinner.

In general, geothermal fluids are tapped through wells, also referred to as "bores" or "bore holes". Except for the higher geothermal temperatures, these wells are similar to oil and gas wells. Geothermal well depths typically range from 600 to 10,000 feet. The fluids surging out of the wells are piped to the power plant. Geothermal steam, or vapor created using geothermal hot water, then spins a turbine-generator to create electricity.

The temperature and quality of the geothermal fluid determines which of the four types of power system that can be used for electrical generation.

Dry Steam Plants. Hot 100% steam is piped directly from geothermal reservoirs into generators in the power plant. The steam spins a turbine-generator to produce electricity. The steam is re-injected into the ground. Dry steam geothermal power plants are rare.

Flash Steam Plants. Fluids between 300°F and 700°F (148–371°C) are brought up through a well. Some of the water turns to steam, which drives the turbine-generator. When the steam cools, it condenses back into water and is re-injected into the ground.

Binary Cycle Plants. Moderately hot geothermal water (less than 300°F) is passed through a heat exchanger. This heat is then transferred to a working fluid (such as isobutene or isopentane) which boils at a lower temperature than water. When that fluid is heated, it turns to vapor which spins the turbine-generator.

Hybrid Plants. Combination of the flash steam and binary cycles.

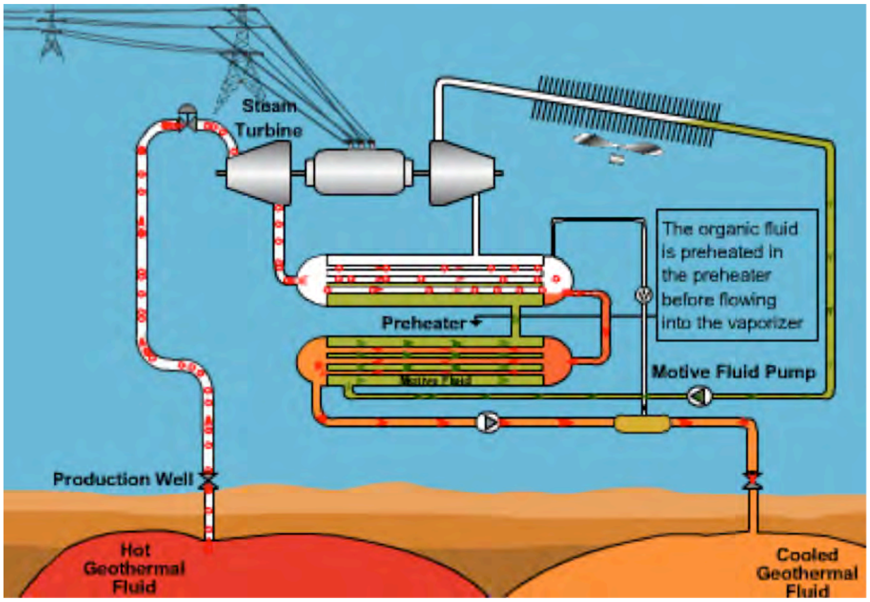

Figure G-12. Geothermal Hybrid Plant

In relation to other renewable energy projects, developing a geothermal power project is relatively complex, and typically involves two major phases: (1) exploratory drilling and (2) project development. The exploratory drilling phase identifies and evaluates potential resources, and drills test well. This phase usually takes a number of years, and in some case, does not identify a viable geothermal resource. After a geothermal resource has been identified, the project development phase begins, which includes drilling production wells and constructing a power plant.

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H. Commercially Ready Technologies

Our analysis for the PSIPs considered both commercially ready generation technologies as well as emerging technologies that, while not commercially ready, might become available during the planning period (2015–2030).

Which emerging technology will be commercially ready before 2030 is impossible to know with any degree of certainty. As a result, with one exception, we did not attempt to decide which of the most promising of the emerging technologies might become available during the planning period. The exception: our analyses performed limited sensitivity of some emerging technologies (for example, Ocean Thermal Energy Storage) to quantify any potential future value.

Our PSIPs are snapshots of the future based on our best available assumptions. As such, *for the PSIPs, we limited the generating resource options to those technologies that are commercially ready as of 2014.*

This planning assumption is for the PSIP analyses only, and does not affect our intent to thoughtfully consider specific projects that include emerging technologies. In other words, we welcome generating technologies not considered in the PSIPs that are proposed in responses to future request for proposals (RFP) for any of our power systems. We will evaluate any proposal on its commercial viability as well as other attributes that are consistent with RFP requirements. Further, nothing in these planning assumptions is intended to modify or change our position for welcoming test projects, pilot projects, or negotiations that involve any specific technology.

COMMERCIAL READINESS INDEX

In order to evaluate whether a technology is commercially ready, the Hawaiian Electric Companies used the Commercial Readiness Index (CRI) methodology developed by the Australian Renewable Energy Agency (ARENA), which was released in February 2014.[1]

NASA first developed a Technology Readiness Level (TRL) in 1974.[2] The TRL ranks technology readiness on a scale of 1 to 9 (1 being the lowest; 9 being the highest level of readiness), with specific attributes identified for each level of readiness.

In 2011, the U.S. Department of Energy published the *Technology Assessment Readiness Guide*,[3] a framework for evaluating energy technologies using the TRL methodology. The TRL methodology characterizes technology readiness from very early stages of a technology life cycle, up to and including commercial readiness.

Building on the work of NASA, ARENA developed a Commercial Readiness Index (CRI), and published the CRI criteria in February 2014 in a document titled *Commercial Readiness Index for Renewable Energy Sectors*.

The CRI scale (1 to 6, with 6 being the highest level of readiness) assesses technology readiness against eight indicators:

- Regulatory environment
- Stakeholder acceptance
- Technical performance
- Financial performance (cost)
- Financial performance (revenue)
- Industry supply chain
- Market opportunity
- Vendor maturity (preference for established companies with strong credit ratings)

ARENA maps its CRI to the TRL, with CRI level 1 corresponding to TRL levels 2 through 8, and CRI level 2 corresponding to TRL level 9. CRI levels 3 through 6, then, include more mature technologies that are closer to commercial deployment, or that are already being used commercially. Except for certain sensitivity analyses, the PSIP did not consider any technologies with a CRI level 4 or less.

1 *Commercial Readiness Index for Renewable Energy Sectors*. Australian Renewable Energy Agency. © Commonwealth of Australia, February 2014. http://arena.gov.au/files/2014/02/Commercial-Readiness-Index.pdf

2 "Technology Readiness Levels Demystified." August 20, 2010. http://www.nasa.gov/topics/aeronautics/features/trl_demystified.html#.U7W-g7ZdV9c

3 Technology Level Assessment Guide. September 15, 2011. http://www2.lbl.gov/dir/assets/docs/TRL%20guide.pdf

To evaluate power generating technologies included in analysis performed for the PSIPs, the CRI methodology provides practical, objective, and actionable guidance. Therefore, we used this methodology to evaluate emerging generation technology options and their suitability for inclusion as resource options in the PSIPs.

For the PSIPs, only those technologies with a CRI Level of 5 or 6 were considered commercially ready, and included as resource options in the PSIPs.

Table H-1 defines the levels of commercial readiness under the CRI methodology.

CRI Level	Commercial Readiness	Definition[4]
6	Bankable grade asset class	Financial investors view the technology risk as low enough to provide long-term financing. Known standards and performance expectations are in place, along with appropriate warranties. Vendor capabilities (including both technology vendors and EPC vendors), pricing, and other market forces drive market uptake ("demand pull").
5	Market competition driving widespread deployment	Competition is emerging across all areas of the supply chain, with commoditization of key components and financial products.
4	Multiple commercial applications	Full-scale technology demonstrated in an industrial (that is, not R&D) environment for a defined period of time. May still require subsidies. Publicly verifiable data on technical and financial performance. Interest from debt and equity sources, although still requiring government support. Regulatory challenges being addressed in multiple jurisdictions.
3	Commercial scale-up	Deployment of full-scale technology prototype driven by specific policy. The commercial proposition is driven by technology proponents and by market segment participants (a "supply push"). Publicly discoverable data is driving interest from finance and regulatory sectors, but financing products are not yet widely available. Continues to rely on subsidies.
2	Commercial trial	Small scale, first-of-a-kind project funded by 100% at-risk capital and/or government support. Commercial proposition backed by evidence of verifiable performance data that is typically not available to the public. Proves that the essential elements of the technology perform as designed.
1	Hypothetical commercial proposition	Technically ready, but commercially untested and unproven. The commercial proposition is driven by technology advocates, with little or no evidence of verifiable technical data to substantiate claims.
0	Purely hypothetical[5]	Not technically ready. No testing at scale. No technical data.

Table H-1. Commercial Readiness Definitions

[4] Based on *Commercial Readiness Index for Renewable Energy Sectors*. Australian Renewable Energy Agency. © Commonwealth of Australia, February 2014. Table 1. p 5.

[5] Not a part of the CRI methodology. Defined here to classify commercial readiness of certain technologies discussed from time to time in Hawai'i.

EMERGING GENERATING TECHNOLOGIES

In Hawai'i, certain emerging generating technologies are discussed as potential generating resource options. The most prominent of these are ocean wave/tidal power, ocean thermal energy storage (OTEC), and concentrated solar thermal power (CSP). We evaluated each of these technologies using the CRI ranking methodology. As objective as the CRI methodology attempts to be, the mapping of the indicators for a given technology is necessarily subjective. Reasonable differences of opinion in the state of any one (or even several) of the eight categories of indicators would not change the overall conclusion regarding the commercial readiness of these technologies.

Summary of CRIs for PSIP Resource Candidates

Table H-2 summarizes the commercial readiness of various generating resource technologies.

Technology	CRI Level							PSIP Resource Option?	Comments
	0	1	2	3	4	5	6		
Simple cycle combustion turbine (CT)							x	Yes	
Combined cycle CT + heat recovery steam							x	Yes	
Internal combustion engines—small							x	Yes	
Internal combustion engines—large							x	Yes	
Geothermal							x	Yes	Constrained on Maui and Hawai'i. None for O'ahu.
Biomass steam							x	Yes	
Biomass gasification			x					No	
Run-of-river hydro							x	Yes	Limited amount of MW available in Hawai'i.

Technology	CRI Level 0	1	2	3	4	5	6	PSIP Resource Option?	Comments
Storage hydro							x	No	No available streams to dam for water storage.
Pumped storage hydro							x	Yes	Not considered for base cases. Sensitivities only.
Ocean wave/ tidal				x				No	
Ocean thermal (OTEC)			x					No	
Wind—onshore utility scale							x	Yes	Limited on O'ahu.
Wind—offshore utility scale					x			No	High capital cost, concerns with ability to site and permit.
Wind—distributed generation				x				No	Approximately 3–4 times more expensive installed cost compared to solar DG-PV.
Solar PV—utility scale						x		Yes	
Solar PV—distributed						x		Yes	
Concentrated solar					x			No	
Fuel cells—distributed			x					No	Primary applications are for "high 9s" reliability applications (e.g., data centers).
Fuel cells—utility scale			x					No	
Micro nuclear reactors		x						No	
Solar power satellites	x							No	
Nuclear fusion		x						No	
Energy harvesting from ambient environment	x							No	Early markets will likely be small scale applications, such as PDA charging.

Table H-2. Commercial Readiness of Generating Technologies Considered for PSIPs

Evaluation of Emerging Technologies

Table H-3 through Table H-5 are CRI assessments of emerging generation technologies that were not included as resource options due to a CRI level of 4 or less.

Table H-3 evaluates wave and tidal power as a potential generating resource as, at best, CRI level 3. Therefore, it was not included for consideration in the PSIPs.

CRI Level	Regulatory Environment	Stakeholder Acceptance	Technical Performance	Financial Performance (Cost)	Financial Performance (Revenue)	Supply Chain	Market Opportunity	Company Maturity
6								
5							Market opportunity widely understood. Additional policy support needed to drive uptake.	
4			Performance understood; high confidence in performance.					
3				Various versions of technologies deployed; Cost drivers beginning to be understood.				
2	Ability to permit across various regulatory jurisdictions untested.	Stakeholder support case-by-case basis.			Revenue projections being tested, however investment community not yet willing to underwrite PPAs on widespread basis.	Supply chain not available. Each project typically unique specification. EPC based on time and materials.		
1								Established industry players not yet part of sector.

Table H-3. Wave/Tidal Power Commercial Readiness Evaluation

Table H-4 evaluates ocean thermal energy conversion as a potential generating resource as, at best, CRI level 3. Even though the CRI level would suggest that OTEC is not eligible for consideration at this time, due to interest in this technology for Hawai'i and our ongoing negotiations with OTEC International to build an OTEC facility to service O'ahu, a sensitivity was prepared to evaluate OTEC as a resource option for O'ahu.

CRI Level	Regulatory Environment	Stakeholder Acceptance	Technical Performance	Financial Performance (Cost)	Financial Performance (Revenue)	Supply Chain	Market Opportunity	Company Maturity
6								
5								
4								Established player (LMCo) considered part of sector.
3							Size of potential market is understood.	
2	Regulatory issues require specific project consideration.	Stakeholder support a case-by-case basis.	Performance forecasts based on pilot project data.	Key costs based on projections. No data at scale.	Revenue projections at scale not tested.			
1						Key elements from specialists.		

Table H-4. Ocean Thermal Energy Conversion (OTEC) Commercial Readiness Evaluation

Table H-5 evaluates concentrated solar thermal power as a generating resource at a CRI level 4. While this resource might be considered during our next planning cycle, it was not included in the PSIPs.

CRI Level	Regulatory Environment	Stakeholder Acceptance	Technical Performance	Financial Performance (Cost)	Financial Performance (Revenue)	Supply Chain	Market Opportunity	Company Maturity
6							Market opportunities clear and understood.	
5					Target is to be cost competitive by 2020.[6]			Leading players with significant balance sheets in sector.
4	Permitting, regulatory challenges based on actual evidence. Policy settings moving to "market pull".	Evidence and experience available to inform stakeholders.	Performance understood. High confidence in future project performance.	Cost drivers understood and tested.	Financing still largely underwritten with government guarantees and subsidies.[7]	Limited supply options but improving.		
3			Multiple technology designs.					
2								
1								

Table H-5. Concentrated Solar Thermal Power (CSP) Commercial Readiness Evaluation

[6] See "*2014, The Year of Concentrating Solar Power.*" U.S. Department of Energy. May 2014.
[7] *Ibid.*

I. LNG to Hawai‘i

Liquefied natural gas (LNG) is critical to reducing customer bills and improving environmental quality in Hawai‘i. High oil prices and more stringent air regulations (the Environmental Protection Agency's Mercury Air Toxic Standards (MATS) and National Ambient Air Quality Standards (NAAQS)) increase the need to reduce Hawai‘i's dependence on oil. While the majority of Hawaiian Electric's current generation portfolio utilizes oil, LNG has emerged as a viable alternative fuel source that may substantially lower fuel costs while reducing greenhouse gas emissions. In late 2012, the Hawaiian Electric Companies and FACTS Global Energy completed studies that confirmed both the technical and commercial feasibility for importing and utilizing LNG in Hawai‘i.

DELIVERING LNG TO HAWAI‘I

Natural gas is not indigenous to Hawai‘i and must first be liquefied into LNG to be cost effectively transported to Hawai‘i. LNG can be imported to Hawai‘i in two ways: bulk LNG or containerized LNG

Bulk LNG. LNG could be transported in bulk via LNG carriers and/or articulated tug barges (ATBs) and received at a bulk LNG import and regasification terminal. The Floating Storage and Regasification Unit (FSRU) is a variant of this option. Pearl Harbor is the best site available for an FSRU when considering factors such as favorable meteorological-ocean conditions, spacious and protected harbor waters, security, cost, and ability to break-bulk (for distribution to the neighbor islands). Natural gas would then be distributed from the FSRU by pipeline to facilities on the individual islands where it would be consumed. Based on our discussions with FERC, we anticipate that a bulk LNG import and regasification terminal project for Hawai‘i will take approximately

6–8 years to complete (1–2 years planning, 2–3 years FERC permitting, and 2–3 years construction) and could possibly be placed in service between 2020 and 2022.

Containerized LNG. LNG could be transported in International Organization for Standardization (ISO) containers using conventional container ships and trucks equipped to handle standard shipping containers. The LNG ISO containers would be delivered directly to the facilities where the LNG would be regasified and consumed. Since FERC permitting is not likely required for LNG delivered by ISO containers, LNG is available today in small quantities, and within a relatively short time for larger quantities.

Containerized LNG RFP

The Company issued an RFP in March 2014, for LNG to be delivered to Hawai'i in ISO containers (Containerized LNG RFP). We have completed our evaluation of the proposals and have identified two proposals for more in-depth discussion with the bidders. We currently anticipate negotiating and executing a contract, and subsequently submitting an application to the Commission in the fourth quarter of 2014.

The Containerized LNG RFP called for deliveries to start within a window from October 1, 2016 to June 30, 2017. Based on confidential information received via the Containerized LNG RFP process, we believe that an LNG delivery commencement date in the latter part of 2017 remains viable if the following five key milestones are realized by their noted deadlines.

1. Finalization of the LNG Sales and Purchase Agreement (SPA) by fourth quarter 2014.
2. Application submission to the Commission by fourth quarter 2014.
3. Final Order to import LNG issued by the Commission by June 1, 2015.
4. Granting of all other major permits by June 1, 2015.
5. Clearance or waiver of any remaining LNG SPA conditions precedent by July 1, 2015.

Upon achievement of these milestones, we will make the investments necessary to construct, assemble and aggregate the various pieces of the supply chain needed to deliver LNG to Hawai'i in 2017. It nevertheless must be recognized that these milestones are challenging, some of which are beyond our control and they will only be realized if no significant legal, environmental, or social obstacles encumber the process.

DELIVERING LNG IN 2017

Liquefaction Capacity

We believe that ensuring the availability of LNG supply from FortisBC is a critical component for successfully concluding the Containerized LNG RFP process with an executed LNG supply and logistics contract. FortisBC's liquefaction capacity is available under a regulated tariff as early as 2017 and capacity is reserved on a first come, first served basis. The Company believed it was critical to directly secure the required capacity from FortisBC before other parties stepped in. For this reason, on August 8, 2014, we executed an agreement with FortisBC for LNG liquefaction capacity under the FortisBC Rate Schedule 46. FortisBC's liquefaction cost, which is less than $2.70, is competitive with other liquefaction rates and is, in fact, lower than any other rate we are aware of (including the rates offered by other Gulf of Mexico liquefaction projects). In addition, because FortisBC is in British Columbia, Canada, they are not subject to the Jones Act and, therefore, can provide substantial marine transport savings to Hawaiian Electric through the use of international shipping assets.

COST OF SERVICE

The range of proposed conditional delivered LNG pricing to O‘ahu power plants and to Hawai‘i Island power plants is extremely favorable, and based on the assumed forecasted 2017 natural gas pricing of $3.58/MBtu.

The pricing mechanisms incorporate pass through provisions of most fixed and variable cost components, with the cost stack to be finalized upon filing of the LNG Sales and Purchase Agreement with the Commission. The build-up of the proposed pricing is based on bidders' current cost estimates, and the ranges for fixed, fixed with escalation, and variable price components.

Included in the fixed cost component are the capital assets (marine assets, ISO containers, etc.) and any services that can be contracted at fixed cost over the term of the SPA. The fixed with escalation cost component include the FortisBC liquefaction costs and other labor costs such as marine terminal handling charges and trucking. Included in the variable cost component is the gas commodity, pipeline toll, and fuel consumed for liquefaction, shipping, and trucking.

The Company and our advisors are undertaking due diligence on the cost elements for each segment in the supply chain. Liquefaction costs are set by FortisBC's Rate Schedule 46 and may be subject to periodic adjustments, if approved by the British Columbia

Utilities Commission (BCUC). Analysis to date suggests that there is little risk of a cost increase over the bidder’s estimates, assuming the above stated milestone are achieved by the milestone dates and the SPA is effective no later than July 1, 2015. Discussions regarding the costs are ongoing with the bidders.

To account for the possibility of stranded assets that could result from a transition to a bulk terminal, a cost adder was included in the LNG forecast between the years of 2017 and 2021 to reflect the potential for a reduced amortization period (5 years versus 15 years).

Transition to Bulk Terminal: 2022

The development of a bulk receiving terminal will be subject to FERC review and approval and therefore cannot be realistically achieved by 2017. Siting of such a terminal, whether floating or land-based, will require substantial engineering analysis and stakeholder socialization. After consulting with FERC, a realistic schedule to develop a bulk LNG terminal is approximately 6 to 8 years.

The Galway Group estimated LNG pricing for 2022 and beyond by using current gas commodity forecasts, liquefaction costs from FortisBC, and estimated costs for shipping of the LNG and for a bulk terminal utilizing a FSRU. We are also assuming annual price increases in our forecasting. The build-up of the LNG forecast for 2022 is as follows:

Item	Price
Gas Commodity	$4.31
Pipeline Header (Fixed)	$0.60
Pipeline Cost of Fuel	$0.11
Marketer Fee (Fixed)	$0.01
Liquefaction (Fixed)	$1.99
Liquefaction Cost of Power	$0.91
Process Fuel Gas	$0.04
B.C. LNG Export Tax	$0.00
Marine Terminal	$0.33
LNG FOB FortisBC	$8.30
Shipping	$1.89
FSRU + Gas Pipeline	$2.54
2022 LNG Forecast w/ Bulk Terminal	$12.73

Table I-1. LNG Itemized Pricing

The LNG price forecast escalates beyond 2022 due to increases in the gas commodity price forecast, which is derived from NYMEX futures-derived forecasted values for Henry Hub; and 2% inflation adjustment applied to fixed with escalation and variable cost components.

J. Energy Storage For Grid Applications

Electricity is a commodity that is most efficiently produced when it is needed. The continuously varying demand for electricity requires utilities to have the appropriate mix of generating and demand-side resources to meet these varying demands. Energy storage is an extremely flexible tool for managing the supply-demand balance.

- Energy storage can be a substitute for generation resource alternatives;
- Energy storage can be used in conjunction with generation to help optimize generation capital costs and reduce system operating costs;
- For system security and reliability applications, storage has unique operational characteristics that may provide benefits not available through other resources.

The ability of energy storage to serve in any one of these roles is dependent upon the cost-effectiveness and operational characteristics of the energy storage asset under consideration, and the operational characteristics of all resources on the system.

Until relatively recently, the only way to store electricity in large (or bulk) quantities has been large mechanical storage devices (for example, pumped storage hydro, compressed air energy storage), which are highly dependent on site availability, may face substantial permitting and public acceptance challenges, have high capital costs and require long lead times (more than seven years) to develop. A new generation of chemical energy storage technologies (that is, batteries with new chemistries) and large-scale flywheel devices add to the commercially available options for energy storage in grid applications. In addition, there may be opportunities to aggregate customer-owned energy storage to provide value to all customers.

The Commission requested in the April 28, 2014 Decisions and Orders (D&Os) that the Companies consider the role that energy storage can play in managing the reliability of the electric grid. More specifically, the D&Os include the following topics for the Companies to address in the PSIPs:

- Discuss potential energy storage technologies and their capabilities;
- Analyze the fundamental benefit and costs of energy storage technologies;
- Discuss how energy storage is utilized in the preferred resource plan;
- Provide a plan for utilization of energy storage resources to address steady state frequency control and dynamic stability requirements, and to mitigate other renewable energy integration challenges;
- Provide a plan to improve utilization of existing energy storage on Maui and Lanai to improve system reliability and reduce system operation costs in those systems;
- Discuss the use of customer-side energy storage;
- Analyze the use of pumped storage hydro to provide ancillary services and bulk energy storage for renewable energy.

The Companies share the Commission's interest in energy storage for providing essential grid services. Energy storage has been integrated with certain independent power producer (IPP)-owned wind and solar projects to help manage ancillary service requirements. A project to design and procure storage for contingency reserves to mitigate the impacts from distributed solar on system security was initiated for the Hawaiʻi Electric Light system. Recently, a Request for Proposals (RFP) for commercial-scale and use of energy services to provide ancillary services was issued by Hawaiian Electric. As more fully described herein, the Companies have also implemented several pilot and demonstration projects.

This Appendix J will address the Commissions' questions about the Companies' plans to utilize energy storage in their systems.

COMMERCIAL STATUS OF ENERGY STORAGE

Pumped storage hydroelectric and compressed air energy storage technologies are mature and proven, with a great deal of performance data in commercial applications. Batteries (particularly lead-acid) and flywheel type energy storage devices have been around for many years and could also be considered mature technologies, but not for grid level applications such as renewable energy integration on island-based grids. The use of batteries and flywheel devices for use in bulk power systems and applications to integrate, or mitigate the impacts of, intermittent renewable energy in island-based electric grid systems is relatively new and there is somewhat limited data regarding their performance in commercial power grid applications. It is therefore worth discussing the status of commercialization of battery and flywheel energy storage for grid applications. This section will discuss several aspects[1] of the status of these technologies in terms of their commercialization. The evidence points to these technologies being at the cusp of commercially readiness.

Regulatory Environment

The regulatory environment for energy storage manufacturers is favorable. Most notably, on October 21, 2013 the California Public Utilities Commission (CPUC) issued the "Decision Adopting Energy Storage Procurement Framework and Design Program[2]." This CPUC decision set a target of 1,325 MW of energy storage to be installed in the three major investor-owned utility systems in California by the end of 2024. Other state commissions are looking at this CPUC decision[3]. This decision provides commercial opportunities for energy storage technology companies and energy storage project developers, and is therefore favorable for the commercial readiness of energy storage technologies. Of interest, the decision excludes pumped storage hydroelectric projects larger than 50 MW, a mature technology, from the target in order to promote development of smaller grid-scale storage projects.

At the federal level, the Federal Energy Regulatory Commission's (FERC) Order No. 755[4], required wholesale markets to develop compensation mechanisms for the provision of frequency regulation, a service that is technically well suited for certain energy storage technologies. The regulatory accounting treatment for energy storage remains an area that will require additional discussions by electric utilities and regulators[5]. For example, energy storage might be implemented for the purpose of relieving grid congestion (functionally classified as transmission), but the same energy storage project might also be able to provide ancillary services (functionally classified as a production service). Grid level energy storage might be implemented to mitigate the effects of variable distributed generation, while at the same time providing other grid support services. However,

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1 See Appendix G for a discussion of the "Commercial Readiness Index" (CRI) and the factors that are considered in determining a CRI.

2 Decision 13-10-040, October 17, 2013 (issued October 21, 2014). PUC Rulemaking 10-12-007. Order Instituting Rulemaking Pursuant to Assembly Bill 2514 to Consider the Adoption of Procurement Targets for Viable and Cost-Effective Energy Storage Systems. Full decision available at: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M079/K533/79533378.PDF

3 "California poised to adopt first-in-nation energy storage mandate." San Jose Mercury-News. October 16, 2013.

4 *Frequency Regulation Compensation in Organized Wholesale Power Markets*. FERC Order No. 755. FERC Docket Nos. RM11-7-000 and AD10-11-000. Issued October 20, 2011. Order 755 available at: http://www.ferc.gov/whats-new/comm-meet/2011/102011/E-28.pdf

5 Bhatnagar, Currier, Hernandez, Ma, Kirby. *Market and Policy Barriers to Energy Storage Deployment*. Sandia National Laboratory. Report SAND2013-7606. September 2013. Report available at: http://www.sandia.gov/ess/publications/SAND2013-7606.pdf

when leveraging storage for multiple purposes, the energy storage must retain the necessary charge level to satisfy the requirements for each use. For example, storage that is deferring transmission investment must retain sufficient charge to handle the transmission constraint; that stored energy cannot be used to provide other services. These situations present issues for regulators in terms of ensuring that the benefits and costs of energy storage are properly allocated.

Stakeholder Acceptance

There are several dimensions to stakeholder acceptance of energy storage technologies, including:

Industry Acceptance: The electric utility industry, including non-utility project developers, has generally accepted grid-scale energy storage technologies as viable solutions for meeting grid needs. This is evidenced by installations of several hundred megawatts of energy storage worldwide in the past few years, including installations in Hawaiʻi in conjunction with wind and solar projects. Automotive applications for batteries in electric vehicles are expected to drive manufacturing costs down for lithium-ion batteries.[6] As a result, utility industry planners expect distributed energy storage to become more economical and are preparing for distributed storage integration into the future grid.

Equitable Regulatory Environment: Monetization of energy storage benefits is generally available in competitive wholesale market environments, where there are markets for capacity, energy and ancillary services. Monetization in vertically integrated utility markets (including Hawaiʻi) is generally driven by the cost effectiveness of energy storage relative to alternatives that provide similar functions. Cost recovery of energy storage systems is for the most part rationalized in the market. It is worth noting that energy storage project installations do not typically qualify for tax incentives, except in limited circumstances[7].

Public Concerns: Energy storage technologies are generally considered to be safe, however, there are public concerns with these systems related to potential fire hazards, toxic waste disposal, and dam breaches.

Financial Community Acceptance: Most of the capital invested in this sector to date has been in the form of venture capital funding, the purpose of which is to commercialize and refine the technologies and develop viable business models. To date, there is no known example of project level debt financing using project debt secured only by the revenues and the project itself (a typical financing model in the IPP industry). Rather,

[6] See for example: http://www.electric-vehiclenews.com/2010/03/deutsche-bank-battery-costs-appear-to.html

[7] For an example of such exceptions, see http://www.chadbourne.com/Large-Batteries-11-30-2011/

most of the projects have been financed off of the balance sheets of the developers themselves. As the market for energy storage becomes more of a "demand-pull" (as opposed to "supply-push") the interest of the mainstream investment community is growing. Several large financial institutions are marketing financing solutions for energy storage8. Some financial analysts predict that distributed energy storage, when combined with distributed solar PV, is on the cusp of being a technology that is disruptive to the traditional utility business model9.

Technical Performance

Although in general this industry is still in the formative stages, the technical performance of energy storage technologies, particular battery, flywheel systems, and pumped storage hydroelectric is well understood. And, with several hundred megawatts of grid-scale energy storage devices installed worldwide, the body of data is growing rapidly. The technical performance of most of the grid-scale energy storage projects to date (excluding pumped storage hydroelectric) is underwritten with technology performance guarantees (with liquidated damages provisions) from well-capitalized, strong balance sheet, engineering-procurement-construction (EPC) contractors and/or project developers.

Distributed energy storage is being marketed to customers interested in PV as well as enabled by the advent of electric vehicles (EV's) and the interest on the part of the sellers of EV's to address consumer "range-anxiety." Improvement in EV battery technology will increasingly find its way into distributed energy storage applications for consumers, including the ability to use EV's as a storage device for energy consumed in a customer's premises.

Financial Performance

The financial performance of energy storage is dependent upon the particular grid application and energy storage technology being deployed. Grid-scale energy storage costs are still relatively high[10]. In general, the cost of energy storage systems is declining, but challenges remain to deliver grid scale energy storage at low costs. Some sources believe that energy storage costs will decline precipitously over the next decade, at a rate of cost decline similar to that experienced with solar PV technology cost[11]. With respect

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8 For example see: http://www.goldmansachs.com/what-we-do/investing-and-lending/middle-market-financing-and-investing/alternative-energy/

9 See for example: http://www.utilitydive.com/news/barclays-downgrades-entire-us-electric-utility-sector/266936/

10 See: Bhatnagar, Currier, et. al.

11 For example, see: http://rameznaam.com/2013/09/25/energy-storage-gets-exponentially-cheaper-too/

to value (benefits) of utility scale grid storage, as technology improves, the ability of energy storage to cost effectively provide grid services also increases.

Industry Supply Chain and Vendor Maturity

While the energy storage industry has its share of venture capital backed startups, large and well-capitalized equipment manufacturers now offer grid level energy storage technologies and solutions. These companies include, but are not limited to: General Electric, Hitachi, LG, Panasonic and NEC. Tesla Motors has recently announced that it is seeking a location for a large battery manufacturing plant in the US, to supply batteries for its EV's. They are actively developing utility uses for these same batteries and may find their way into grid storage applications, including distributed energy storage. Many of the smaller startups and niche players enjoy investments from, and strategic partnerships with, larger companies. These trends indicate that larger manufacturing companies are making the investments in sales, manufacturing, and service ecosystems that support the long-term viability of the energy storage industry. To date however, there is a lack of standardization in the energy storage industry.

Market Opportunity

The market opportunity for grid-scale energy storage is clearly validated by successful deployments worldwide and by regulatory mandates for energy storage as described above. Distributed energy storage is also viewed as a large market opportunity.

In conclusion, while the grid-scale energy storage industry is clearly in the early stages of commercial viability, it is well beyond the "technology development" stage for many of the available technologies. The Companies can be reasonably confident that energy storage solutions are available that can be designed, financed, constructed, operated and maintained in a manner consistent with the way the Companies deploy other kinds of utility grid infrastructure.

ENERGY STORAGE APPLICATIONS

Defining Characteristics of Energy Storage

Stored energy is generally referred to in physics as "potential energy." Potential energy is found in various forms; for example, the chemical energy stored in the form of a fuel, mechanical energy stored in a spring, gravitational energy stored in water in a reservoir, etc. In practice, most energy storage systems are used to store energy for use (that is, conversion to "kinetic energy") at a later time.

Energy storage systems of interest for electricity grid applications can be defined by the following set of characteristics:

Storage: Amount of energy that can be stored (measured in megawatt-hours)

Capacity (or rate of discharge): the rate (quantity per unit of time) at which the energy storage device can deliver its stored energy to the grid (typically measured in megawatts).

Storage Duration: Hours or minutes of energy storage (this is the amount of energy that can be stored divided by the rate of discharge).

Maximum Depth of Discharge: This is defined by the energy stored in the device at its minimum level divided by the total energy storage. This is a limiting factor in terms of the actual duration of delivery of stored energy from the device to the grid, since once the device reaches its maximum depth of discharge it cannot release any more of its stored energy. This can be a function of chemistry (for example, in a battery) or physical design (for example, in a pumped storage hydroelectric reservoir).

Round trip efficiency: This is the ratio of stored energy available for "release" from the device (AC energy out) to the amount of energy that must be expended to "fill" the device (AC energy in). The perfect storage device would have 100% round trip efficiency (that is, the energy output of the storage device would be equal to the charging energy required.) Actual storage efficiencies range from 70% to 90% depending upon the type of device, size and technology.

Duty Cycles Available: The number of charge/discharge cycles available from the device during a given period of time (measured in cycles per unit of time, for example, cycles per year, cycles per minute).

Grid Applications for Energy Storage

Generalized energy storage applications in electric power grids include the following:

Load Serving Capacity: Energy storage devices can be used to provide the equivalent of generating capacity, provided that the available storage duration is long enough (typically hours). Practical applications include substitution for peaking plants such as combustion turbines in markets where additional capacity is required[12]. In such an application, lower cost generating resources would be used to "fill" the energy storage device, and the stored energy would be released at a later time during peak hours. Load serving capacity requires relatively long storage durations (at least 3 hours to qualify as

[12] Denholm, Jorgenson, Hummon, Jenkin, Palcha, Kirby, Ma, O'Malley. The Value of Energy Storage for Grid Applications. National Renewable Energy Laboratory. NREL/TP-6A20-58465. May 2013. Available at: http://www.nrel.gov/docs/fy13osti/58465.pdf

"capacity" for the Companies' systems) but relatively infrequent use in terms of duty cycles (perhaps 50 – 100 cycles per year).

Time Shifting of Demand and Energy: Energy storage can be used to "shift" demand from one time period to another. Time shifting (also referred to as "load shifting") applications also typically require long duration (hours) of storage in order to be effective. In markets with substantial on-peak/off-peak energy price differentials, storage is valuable in financial arbitrage. In Hawai'i, there is not a large differential between the on peak and off-peak marginal cost of energy production; therefore, price arbitrage is not a primary consideration for energy storage at the grid level. Time shifting using energy storage may be useful in Hawai'i for managing the variability of some renewable energy resources, or to capture the available energy production from variable resources and store it for use at a later time, rather than "spilling" the available energy. Time shifting also requires relatively long storage durations, with the number of duty cycles being dependent on the nature of the market (for price arbitrage) or relative penetration of variable renewable energy and the frequency of curtailment events that could be avoided using energy storage.

Sub-Second Response: Fast acting energy storage can be used to supplement inertia and limit under-frequency load shedding that would occur during faults and other abnormities that occur on the grid, such as loss of generation. See Appendix E, Essential Grid Services.

Power Quality: Some energy storage devices can provide power quality and "ride-through" service. Power quality refers to the quality of the AC voltage in the system. Some energy storage devices can respond to changes in AC voltage by absorbing and releasing energy to "smooth" the sinusoidal AC waveform. For example, this type of functionality is used for some wind plants to ensure that equipment remains connected through transient system conditions.

These energy storage applications and the operational requirements associated with them are mapped in Figure J-1.

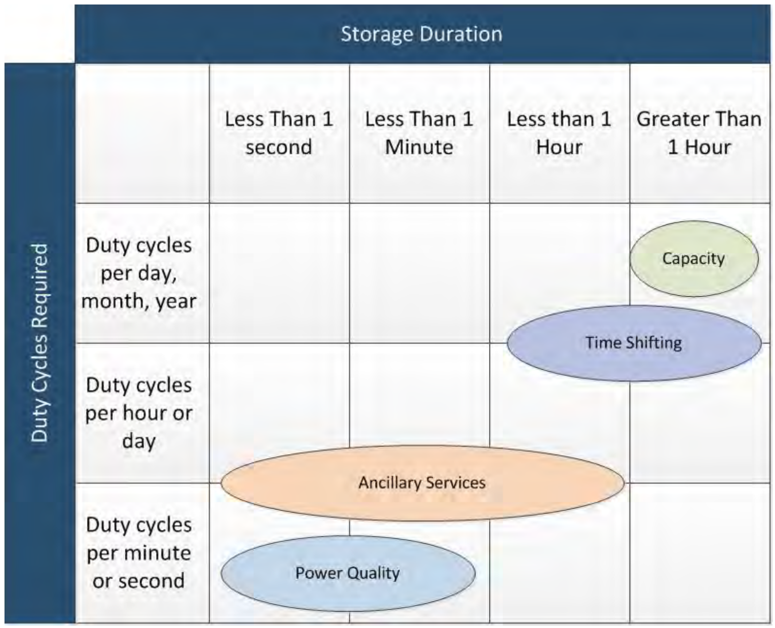

Figure J-1. Energy Storage Applications[13]

ENERGY STORAGE TECHNOLOGIES

Energy storage technologies can be categorized in terms of the physics utilized to store energy. These categories and the types of specific technologies include:

Mechanical: pumped storage hydroelectric (PSH), compressed air energy storage (CAES), flywheels. Underground CAES is not considered viable in Hawaiʻi due to lack of suitable geographic features and structural features conducive to CAES. However, aboveground CAES may be technically viable, but has not been considered at this time. PSH and flywheels are considered for Hawaiʻi and are discussed below.

Electrochemical: secondary batteries (lead-acid, lithium ion, other chemistries)[14], flow batteries. Lead-acid batteries, lithium ion and flow batteries are considered for Hawaiʻi and are discussed below.

Chemical: hydrogen (H_2), synthetic natural gas (SNG). These technologies are not considered for near-term applications in Hawaiʻi. A hydrogen infrastructure is, at best, a

[13] Adapted from International Electrotechnical Commission (IEC) Electrical Energy Storage Whitepaper, December 2011. Available at: http://www.iec.ch/whitepaper/pdf/iecWP-energystorage-LR-en.pdf

[14] "Primary" batteries cannot be recharged (for example, a dry cell flashlight battery). In "Secondary" batteries, the charge/discharge cycle can be reversed, meaning that secondary batteries can be recharged.

decade away. SNG is not economically viable as the round trip efficiency in very low (about 36%)[15].

Thermal: ice storage and grid interactive water heating. Ice storage and other forms of thermal energy storage are not considered here for bulk power applications. Several companies market thermal ice storage systems for managing end-use load (typically air conditioning) against tariff price signals[16]. Thermal energy storage can be useful for implementation by end-users in response to time-based pricing programs that are part of the Companies' demand response initiative (for example, grid interactive water heating).

Electrical: ultra-capacitors, superconducting magnet. These technologies are on the cusp of commercially readiness for grid-scale applications. Ultra-capacitors are increasingly being used in power quality applications[17]. Indeed, the Hawi wind plant in the Hawai'i Electric Light system utilizes an ultra-capacitor to ensure it remains connected through grid transients.

The following subsections briefly discuss the specific energy storage technologies that have been assumed to be available for consideration in the PSIP's. The inclusion of these technologies, and the exclusion of others, does not imply that the Companies are closed to considering other technologies. Specific energy storage proposals will be evaluated on their merits, including the commercial readiness of the technology proposed, utilization in specific grid-scale applications, and other relevant factors.

Flywheels

Flywheels are mechanical devices that store energy in the angular momentum of a rotating mass. The rotating mass is typically mounted on a very low friction bearing. The energy to maintain the angular momentum of the rotating mass is supplied from the grid. During a grid event, such as a sudden loss of load, the inertia of the rotating mass provides energy to drive a generator, which provides replacement power to the grid.

Flywheels are useful to provide inertial response in a power system. They are also increasingly used in commercial applications to provide fast-response, short-term "ride-through" capability that allows seamless transfer of load from the grid to a longer-term backup system such as an emergency generator. Flywheels display excellent load following characteristics over very short duration timeframes. Thus, they are well suited for providing frequency regulation and contingency reserves.

15 Pascale. KU Leuven. *Energy Storage and Synthetic Natural Gas.* (undated). Available at: http://energy.sia-partners.com/files/2014/05/Paulus_Pascale_ArticleUpdated1.pdf

16 See for example Ice Energy. http://www.ice-energy.com/

17 Daugherty, Leonard. SolRayo. *Ultracapacitors for Renewable Energy Storage*. (undated). Available at: http://www.solrayo.com/SolRayo/Presentations_files/Ultracapacitors_for_Renewable_Energy_Storage_Webinar.pdf

The capital cost of flywheels is fairly high. However, flywheels can provide hundreds of thousands of charge/discharge cycles over their useful life. Flywheel energy storage can be developed in two years or less, not counting regulatory approval lead-times. The round trip efficiency of a flywheel storage system is approximately 85%.

Other than specific site considerations, flywheels have very little environmental impact. Modern metallurgy has produced flywheel technologies that are safe during operation. Several vendors have designs that place flywheels underground for additional safety.

Advanced Lead Acid Batteries

Lead-acid batteries were invented in the mid 19th century. Conventional lead-acid batteries are characterized by low energy density (the amount of energy stored relative to the mass of the battery), relatively high maintenance requirements, and short life cycles. Their principle advantage is the ability to deliver high current over long duration timeframes. Disposal of lead-acid batteries presents environmental considerations, but recycling techniques are well established.

Advanced lead-acid batteries or "UltraBatteries" are now reaching the market. UltraBatteries combine conventional lead-acid batteries with electronic ultra-capacitors to provide high duty cycles. The supercapacitor enhances the power and lifespan of the lead-acid battery, acting as a buffer during high-rate discharge and charge[18]. This makes the UltraBattery a low cost, durable battery technology, with faster discharge/charge rates and a life cycle that is two to three times longer than a regular lead-acid battery[19].

Like all chemical energy storage systems, capital costs for advanced lead acid batteries are still relatively high for grid-scale applications. Round trip efficiencies are also high at around 90%.

Grid-scale advanced lead acid battery projects can be developed in two years or less, not counting regulatory approval lead-times.

The high market penetration of lead-acid batteries in automotive applications has led to successful lead-acid battery recycling programs. Not only does recycling keep lead out of the waste stream, recycling supplies over 80% of the lead used in new lead-acid batteries.[20]

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[18] *UltraBattery: No Ordinary Battery*. Australian Commonwealth Scientific and Industrial Research Organisation (CISRO). Available at: http://www.csiro.au/Outcomes/Energy/Storing-renewable-energy/Ultra-Battery/Technology.aspx

[19] *Ibid.*

[20] Conger, Christine. "Are Batteries Bad for the Environment?" Discovery News. September 16, 2010. Available at: http://www.nbcnews.com/id/39214032/ns/technology_and_science-science/t/are-batteries-bad-environment/#.U_ATm-VdVS8

Lithium Ion Batteries

"Lithium-ion" refers to a wide range of chemistries all involving the transfer of lithium ions between electrodes during charge and discharge cycles of the battery[21]. Lithium ion batteries are very flexible storage devices with high energy density, a fast charge rate, a fast discharge rate, and a low self-discharge rate, making lithium ion batteries ideal for grid applications[22].

Capital costs for lithium ion batteries are declining[23], particularly as the use of lithium ion for electric vehicle batteries rises. Lithium ion batteries themselves have a useful life through 400-500 normal charge/discharge cycles. More frequent use of the full charge/discharge capabilities of lithium ion would shorten the life. Lithium ion battery energy storage can be developed in two years or less, not counting regulatory approval lead-times.

The round trip efficiency for lithium ion technology is around 90%.

Lithium ion batteries do not contain metallic lithium, nor do they contain lead, cadmium, or mercury. Thus, disposal of lithium ion batteries is not a major issue. At the end of their useful life, lithium ion batteries are dismantled and the parts are reused.[24] Overcharging certain lithium ion batteries can lead to explosive battery failure. Thus, the overall safety of lithium ion batteries in grid applications is a function of mechanical design and control systems.

Flow Redox Batteries

A flow battery is charged and discharged by a reversible reduction-oxidation ("redox") reaction between two liquid electrolytes of the battery. Unlike conventional batteries, electrolytes are stored in separated storage tanks, not in the power cell of the battery. During operation, these electrolytes are pumped through a stack of power cells, in which a chemical redox reaction takes place and electricity is produced. The design of the power cell can be optimized for the power rating needed, since this is independent of the amount of electrolyte[25].

Advantages of flow batteries include virtually unlimited cycle life and fast charge/discharge times for the electrolyte, but the power cells do require periodic replacement. Increasing the size of the electrode stack can increase the power output of a

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[21] Energy Storage Association. http://energystorage.org/energy-storage/technologies/lithium-ion-li-ion-batteries

[22] *Lithium Ion Technical Handbook*. Gold Peak Industries (Taiwan), Ltd. http://web.archive.org/web/20071007175038/http://www.gpbatteries.com/html/pdf/Li-ion_handbook.pdf

[23] See for example: http://rameznaam.com/2013/09/25/energy-storage-gets-exponentially-cheaper-too/

[24] See for example: http://auto.howstuffworks.com/fuel-efficiency/vehicles/how-green-are-automotive-lithium-ion-batteries.htm

[25] This paragraph taken from: http://www.imergypower.com/products/redox-flow-battery-technology/

flow battery, and the storage capacity (energy) can be increased by increasing the size of electrolyte storage (or volume of electrolyte tanks). Flow batteries are useful for longer storage duration (hours) applications. Their relatively high capital costs make them less useful for ancillary service applications. Flow batteries are generally considered safe, an important issue for grid-scale batteries where thermal runaway of conventional batteries may cause fire[26].

Capital costs for flow batteries are still relatively high. The round trip efficiency of a flow battery is relatively low at around 72%.

Pumped Storage Hydroelectric

Pumped storage hydroelectric (PSH) is a mature technology that has been successfully implemented around the world in grid applications. In a pumped storage hydro system, water is pumped to a higher elevation using energy made available from generating resources that are otherwise unused (for example, low marginal cost off-peak energy or excess renewable energy that would otherwise be curtailed, etc.). During high demand periods, this stored water drives a hydroelectric pump-turbine to generate electricity.

Pumped storage hydroelectric has a relatively high capital cost, but has a useful life typically in excess of 50 years. Pumped storage is very efficient with round trip efficiencies approaching 80%.

Pumped storage hydro installations are very site dependent. Pumped storage investigations in Hawaiʻi have previously identified several potential sites in the Companies' service territories, with available output capacities typically less than 100 MW in size. Pumped storage hydro installations also face substantial siting and permitting challenges, particular where new reservoirs must be constructed and subsequently flooded. Because of the site specific challenges and the substantial engineering and construction efforts required to build a PSH project, the typical development time for pumped storage is seven years or longer, posing challenges to the utility planner, particularly in an environment where the need to deliver solutions in the near term is paramount.

Due to the inherent economies of scale, the preponderance of pumped storage hydroelectric installations in the United States are typically hundreds or even thousands of megawatts in size. There is very limited data on capital cost and performance for operating pumped storage hydroelectric installations that are less than 100 MW in size.

Pumped storage hydro is a very useful technology for providing peaking capacity and time shifting capabilities. While pumped storage hydro is a quick-start resource, the

[26] Lamonaca, Martin. "Startup EnerVault Rethinks Flow Battery Chemistry." MIT Technology Review. March 22, 2013.

water column constant of a typical pumped storage system is about 7 seconds (that is, this is the time it takes to get the water moving through the turbine to produce electricity). This is a limiting factor with respect to the utilization of an off-line pumped storage system for providing certain ancillary services. The utilization of adjustable speed pump turbine technology in pumped storage hydroelectric projects can provide operating flexibility compared to conventional pump turbines. The main advantage of using adjustable speed technology is the ability to provide more precise power control. This power control can be maintained over a wider operating range of the pumped storage hydroelectric system, allowing the utility to provide ancillary services, such as frequency regulation, spinning reserve, and load following, in both the generation and pumping modes. These benefits and other attributes of an adjustable speed pump turbine can translate into increased operating efficiencies, improved dynamic behavior, and lower operating costs.

Unlike a battery, which already has charge, or a flywheel that has angular momentum, the start of a pumped storage charging cycle requires the delivery of high levels of electric current to start the motors necessary to pump water to the higher elevation. To put this in perspective, a 30 MW pumped storage system in the Hawai‘i Electric Light system would require staring 37.5 MW of motor load (assuming an 80% round trip efficiency). The typical daily peak demand of the Hawai‘i Electric Light system is about 150 MW. Therefore, the start of the motor would represent an instantaneous load increase of 25% on the system. This may result in currents that exceed the short circuit limits of the transmission system, and without mitigation this would result in a significant frequency disturbance.

The primary environmental impacts from pumped storage hydro occur during construction. If construction of new reservoirs and/or water diversion is required, this can lead to substantial permitting challenges.

ECONOMICS OF ENERGY STORAGE

Energy Storage Capital Cost

The costs assumed in the PSIP's for energy storage systems are generally based on actual proposals for energy storage systems and flywheels, and from a combination of sources for pumped storage hydroelectric. The cost of energy storage for any given storage technology is in part a function of the duration of storage required. Table J-1 summarizes the capital costs assumed for the PSIP's mapped against the specific grid services required in the Companies' systems[27].

Grid Service	Storage Duration / Discharge	Technology				
		Flywheel $/KW	Advanced Lead Acid $/KW	Lithium Ion $/KW	Flow Redox $/KW	PSH $/KW
Inertial, Fast Response Reserves	0.05 min / 5000 cycles per year	$997	NA	NA	NA	*
Regulating Reserves	30 min / 1000 cycles per year	$4,459	$1,005	$1,179	$1,596	*
Contingency Reserves	30 min / 20 cycles per year	$2,263	$802	$942	$1,079	*
Capacity, Long-term Reserves	> 3 hours / 50 cycles per year	NA	$4,531	$5,401	$2,559	$4,500[28]

Costs include EPC, land, and overheads. Costs do not include AFUDC. NA = not economic, or unable to provide this service. * PSH may be able to provide these services when operating, but because the upper reservoir capacity of a given pumped storage project site is defined by geology and other factors, PSH would not typically be economical to build for the sole purpose of providing very short duration services.

Table J-1. Energy Storage Technology Capital Cost Assumptions (2015 Overnight $/KW)

Energy Storage Fixed O&M

The PSIP fixed O&M cost assumptions for energy storage were also based on actual proposals, except for pumped storage hydroelectric, which is based on NREL data. Table J-2 summarizes the storage fixed O&M costs.

Grid Service	Storage Duration / Discharge	Technology				
		Flywheel	Advanced Lead Acid	Lithium Ion	Flow Redox	PSH
Inertial, Fast Response Reserves	0.05 min / 5000 cycles per year	58	NA	NA	NA	NA
Regulating Reserves*	30 min / 1000 cycles per year	264	31	32	43	NA
Contingency Reserves	30 min / 20 cycles per year	108	25	27	29	NA
Capacity, Long-term Reserves	> 3 hours / 50 cycles per year	NA	90	105	62	29

Table J-2. Energy Storage Fixed O&M Assumptions (2015 $/KW-Year)

[27] See Appendix E for a discussion of Essential Grid Services in the Companies' systems.

[28] There is relatively little actual data available regarding the cost of utility-scale pumped storage projects less than 100 MW in size. This capital cost assumption for pumped storage used in the PSIP analyses was determined though evaluation of a number of different sources, including a review of confidential screening-level cost estimates for site specific projects in Hawai'i, estimates for a 50 MW pumped storage project in the United Kingdom, NREL data, U.S. Energy Information Administration data, and conversations with a potential pumped storage developer in Hawai'i.

Energy Storage Variable O&M

The PSIP variable O&M cost assumptions for energy storage were also based on actual proposals, except for pumped storage hydroelectric O&M, which is based on NREL data. The variable O&M costs for batteries is solely related to battery and cell replacements and disposal at the end of the duty cycle of the batteries which are assumed to require replacement due to high number of charge/discharge cycles per year associated with provision of regulating reserves. Table J-3 summarizes the storage variable O&M costs

		Technology				
Grid Service	Storage Duration / Discharge	Flywheel	Advanced Lead Acid	Lithium Ion	Flow Redox	PSH
Inertial, Fast Response Reserves	0.05 min / 5000 cycles per year	NA	NA	NA	NA	NA
Regulating Reserves*	30 min / 1000 cycles per year	-0-	88	45	30	NA
Contingency Reserves	30 min / 20 cycles per year	NA	NA	NA	NA	NA
Capacity, Long-term Reserves	> 3 hours / 50 cycles per year	NA	NA	NA	NA	59

Table J-3. Energy Storage Variable O&M Cost Assumptions (2015 $/MWH)

Benefits of Energy Storage

In the Companies' systems, energy storage can be used for several purposes.

- Capacity to serve load
- Manage curtailment of variable renewable generation
- Ancillary services
- Integration of renewables

Benefits of energy storage for each of the above uses depend upon specific operating conditions, the capacity adequacy situation in each of the operating systems, and the other resource options available. In general, energy storage can also be used for multiple purposes. For example, energy storage installed to provide capacity to serve load, could also be available to provide ancillary services, provided it is not being used in its load-serving mode. However, if the storage asset is will be used for multiple purposes, it must be designed to ensure the energy allocation and response capability can serve the combined needs. For example, storage used for contingency reserves must be kept at the necessary charge level to provide the required reserve. If also providing regulation, additional energy storage capacity would be required above the minimum required to meet the contingency reserve requirement.

Capacity

Energy storage can provide capacity to serve load on the Companies' systems, provided that there is a need for capacity[29] and provided that there is the appropriate duration of energy storage available to qualify as capacity[30]. During the PSIP planning period, the Hawaiian Electric and Maui Electric systems are expected to add capacity to replace retiring generation. Thus, energy storage is one of the alternatives that must be considered for providing that capacity.

Figure J-2 conceptually depicts the economic comparison of energy storage to generation for providing capacity.

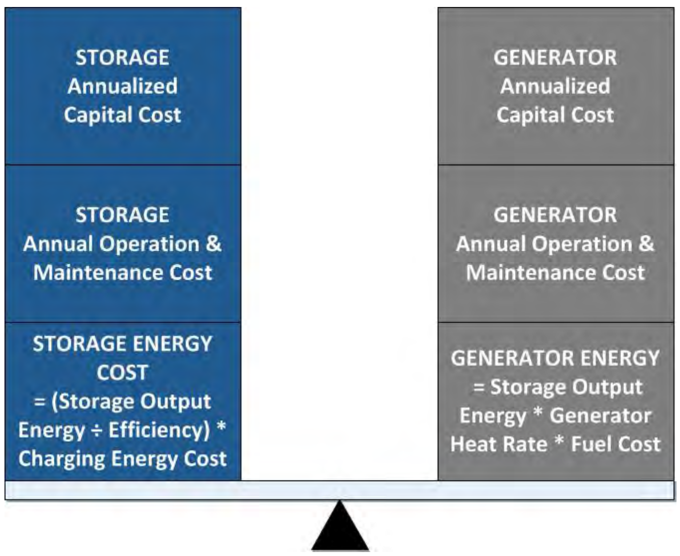


Figure J-2. Energy Storage Economics for Capacity

In this comparison, the energy storage device is compared on a one-for-one basis as a substitute for a generator. A levelized utility revenue requirements factor is applied to the total capital cost of the storage and the generator to determine the annual capital costs. The O&M costs associated with the two alternatives are determined. And finally, the cost of the energy output from each of the assets is computed. In the case of the storage technology, the round trip efficiency must be taken into account, because more energy is required to charge the energy storage asset than is usefully delivered from the same energy storage asset. If the total cost of the energy storage asset were less than the cost of the generator, energy storage would be the most economical alternative[31]. Note that in the case where capacity is not needed, the capacity cost of the generator would be

[29] Denholm, Jorgenson et. al.

[30] Storage is a finite energy resource. When used as a capacity resource, the storage must be carefully designed for the appropriate duration, and the storage energy must be utilized in an appropriate manner. The Companies' criteria require that a resource be able to deliver energy for 3 continuous hours in order to qualify as capacity.

[31] In a proper analysis, any differences in ancillary service costs or benefits associated with the alternatives being compared will also be included.

zero, because existing generation (whose capital cost is sunk) would be able to provide amount of energy required by the system.

Managing Curtailment

Energy storage used to manage variable renewable energy curtailment is an example of a time shifting application for storage, and may have use in the Companies' systems. Energy storage can absorb variable renewable energy that is produced when it is not needed, and return that energy (less round trip losses) to the system at a later time. Figure J-3 conceptually depicts the economics of energy storage in managing curtailment.

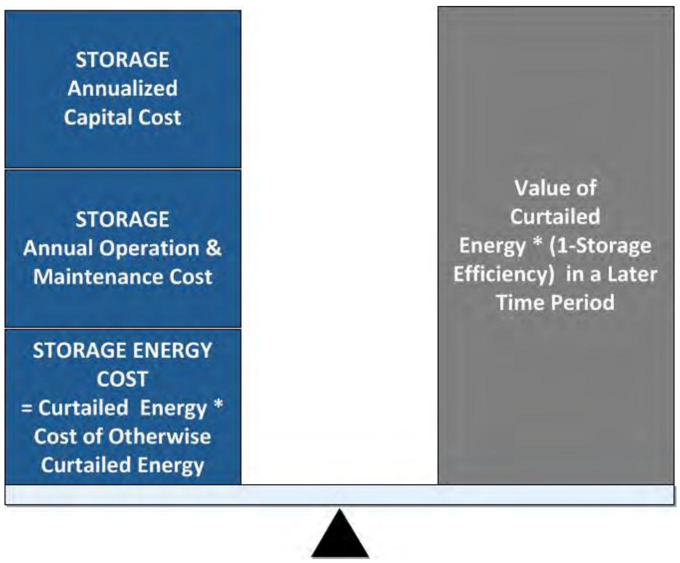


Figure J-3. Energy Storage Economics for Managing Curtailment

The basic economic equation in Figure J-2 is a comparison of the cost of the energy storage versus the value of energy in a later time period of energy that would have otherwise been curtailed (less the round trip efficiency losses since that those losses will not be returned to the system). Note that in Figure J-2 there is a cost associated with the curtailed energy used to charge the energy storage device. Absent the energy storage asset, the payment for the curtailed energy would have been avoided. Thus, this is a cost that is borne by the ratepayer that would otherwise have not been incurred. Further study of Figure J-2 will reveal that the cost comparison includes the capital cost of the energy storage, but it does not explicitly include any capacity value (that is, capital cost) associated with use of the energy in a later time period. Unless there are severe capacity constraints in the system where new capacity is required, the capacity value of the energy used at a later time is essentially zero. At current Company system marginal cost levels, it would almost never be economical to build energy storage exclusively for the purpose of managing energy curtailment. Rather, it is more likely that an energy storage asset already installed for another purpose could also be used to manage curtailment.

Ancillary Services

Energy storage can be used to provide ancillary services, provided that it can respond in the time frames necessary and operate in a coordinated fashion with other generation and demand response resources on the system. Using energy storage to provide ancillary services slightly increases total amount of energy that must be generated in the system due to the round trip losses associated with the energy storage asset. The charging energy may come from thermal resources or from variable renewable resources. However, energy storage may allow energy production costs to be reduced if provision of ancillary services is causing a constraint on the economic commitment and dispatch of generating units. These economics are depicted in Figure J-4.

The value of the energy storage asset in this situation is based on production cost savings (fuel and O&M) that are incurred by storage supplying the ancillary services. Calculation of these benefits requires production simulations.

If capacity is required in the system, short duration energy storage may be more cost effective than adding new generating capacity. If that is the case, the capital cost of the new generation must be added into the benefits that storage can provide.

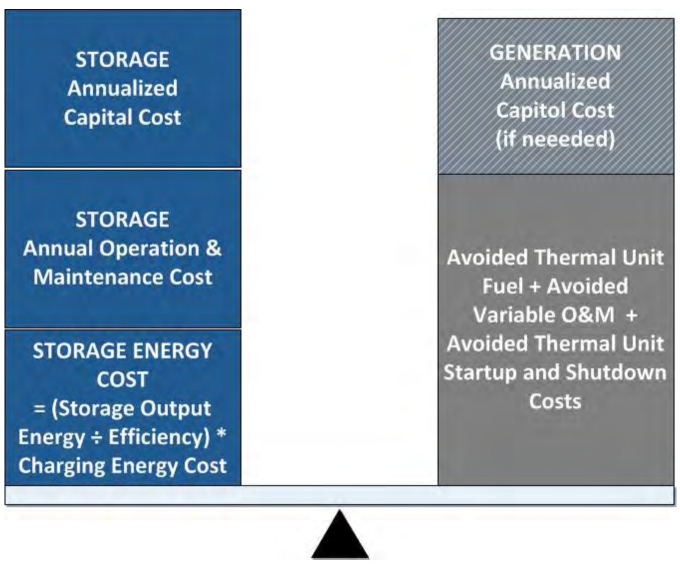


Figure J-4. Energy Storage Economics for Ancillary Services

Integration of Renewables

Another possible use of energy storage in conjunction with renewable energy is to combine the installation of a variable renewable generator with the installation of energy storage. This has been accomplished in the all three of the Companies' main operating systems. The value of this configuration for customers is that it essentially allows the storage to be leveraged to minimize the ancillary service requirements created by the variable generator that would otherwise have to be provided by other resources on the system. Location of storage at the plant allows the sizing to be designed for the plant needs; co-location also simplifies the communications control interface. From a system standpoint, the storage/generation combination is treated as a plant with the combined operational/technical capabilities of the turbines and storage. The economic evaluation is essentially the same as that portrayed for ancillary services in Figure J-4.

It should be noted that in several cases, the installation of the energy storage was feasible only because it was bundled with generation in a way that allowed the project developer to obtain tax advantages for the energy storage that would not be available for a standalone energy storage asset. In other words, energy storage added value to the generation.

Unless marginal thermal generation costs were much higher than they are today, the converse is not true (that is, adding generation does not add value to storage). It does not make economic sense to build excess renewable generators exclusively to provide energy to charge storage assets since in doing so, the marginal capital cost would be the sum of the generator capital cost and the storage capital cost. Rather, it is important that the system be planned to optimize all resources, including generation, demand response, and storage to achieve the lowest cost.

K. Capital Investments

This information represents the 2015–2030 capital expenditure budget for the Hawaiian Electric Company.

TRANSFORMATIONAL INVESTMENTS

The transformation of the O‘ahu electric grid to reliably and cost effectively enable more renewable generation requires significant investment in virtually every aspect of the business. Investments ranging from new renewable generation resources to enabling technologies for demand side resources and from DGPV enabling grid reinforcements to infrastructure for lower-cost LNG fuel will transform our Island grid. These transformative investments are described below more in depth.

Liquefied Natural Gas (LNG)

In an effort to reduce customer costs, Hawaiian Electric is pursuing two non-exclusive approaches to import lower-cost LNG to Hawai‘i: importation of LNG via ISO (International Organization for Standardization) containers (containerized LNG); and/or importation of LNG via bulk LNG carriers (bulk LNG).

The concept of containerized LNG would involve using conventional container ships and trucks equipped to handle ISO containers. The LNG ISO containers would be delivered directly to the generating stations where the LNG would be regasified and consumed. Shipping and distribution of containerized LNG to Hawai‘i in volumes sufficient for power generation may possibly be commercialized within three years or less.

The bulk LNG concept would involve transporting LNG across the ocean via LNG carriers and/or articulated tug barges, and receiving it at a bulk LNG import and regasification terminal (likely located in Pearl Harbor). Once regasified, natural gas would be distributed by pipeline to generating stations where it would be consumed. It is anticipated that development, permitting, and implementation of a bulk LNG import and regasification terminal for Hawaiʻi will take up to eight years to complete, and could possibly be placed in service in 2020 to 2022.

Regarding containerized LNG, Hawaiian Electric solicited offers from third parties for containerized LNG deliveries via a March 11, 2014 request for proposals (RFP) and final bids from three potential suppliers were received on May 24, 2014. The responses to the RFP indicate that containerized LNG could be delivered to generating stations on Oʻahu and neighbor islands up to an approximate 30% discount below current petroleum fuel prices. Based on these proposals, Hawaiian Electric intends to move forward as quickly as it can to bring containerized LNG to Hawaiʻi and to use it in existing and future replacement generating units.

It appears that importing containerized LNG will have the potential of saving the Companies' customers throughout the state substantial amounts on fuel costs. The amount of the savings will depend on the prices for the fuels that are displaced once LNG is available, and the final prices from the on-going RFP. It is uncertain at this time whether a bulk LNG delivery solution would provide as much, the same or more of a cost benefit to customers. Therefore, Hawaiian Electric will continue to pursue the bulk LNG concept as long as there is a potential that it will provide additional benefits and value to our customers.

System Security Investments

To reliably operate a grid rich in variable renewable generation requires the grid operator to manage a new, and to some extent not fully known, set of electrical system security issues. When such a grid is a small islanded system such as Oʻahu, the criticality of these issues is further heightened, as compared to the large, interconnected grids of North America. The Company's system security analyses, coupled with the PSIP planning processes, have defined a number of new investments required to meet these system security challenges. These investments, "Energy Storage – Contingency Reserve" and "Energy Storage Regulating Reserve," enable the Company to comply with its system security and reliability standards by 2016 and maintain compliance with these standards through the remainder of the study period.

Investments also include telecommunications infrastructure additions to provide SCADA functionality to all distribution substations. SCADA provides for information and control of distribution substation devices for improved reliability and situational awareness. It also provides the communication link to communicate with utility and customer equipment located within and connected to distribution circuits. These include communications to facilitate dynamic under frequency load shedding; provides a "backhaul" for Distribution Automation, AMI, and other Smart Grid technologies; and is a necessary communications link to take advantage of "smart" inverter capabilities, including inverter status, voltage regulation, active inverter control/regulation, and other functionality as described in the DGIP.

Additionally, investments will also include a new Energy Management System (EMS) to replace the current EMS when it reaches the end of its product lifecycles and to take advantage of state-of-the-art hardware and software technologies to properly operate a grid with significantly more monitoring and control points than in the past and to allow for the coordinated operation of the system – both automatic generator controls and T&D switching—and also to interface with the Advanced Distribution Management System (ADMS) and Outage Management System (OMS) planned to allow for coordination with circuit/area-level grid operations such as DR, DA, DG, EV and operations and monitoring of other DERs.

Facilitation of New or Renewable Energy

138KV Transmission Loop

A new 138kV transmission line from Ko'olau Substation to Wahiawa Substation (along the windward, northern, and central areas of the island) would accommodate additional renewable energy in the future on the central and northern areas of O'ahu. This transmission line would be approximately 55 miles. Currently, no transmission circuits exist on this part of the island. In addition, at least one new transmission substation would be required along the 138kV line. The transmission substation would be built to accommodate an ultimate design for six 138kV breakers (in a breaker-and-half scheme), two 138-46kV, 80MVA transformers, a 46kV ring bus, and four 46kV feeder breakers.

The existing 46kV feeders serving the North Shore and Kahuku areas from Wahiawa Substation and Ko'olau Substation are already at their capacity limits with existing and proposed wind farms and PV generation. Adding this new transmission line with a new transmission substation would add 46kV capacity that can accommodate additional renewable generation on that side of the island. It would also increase the grid reliability on the North Shore area and strengthen power quality.

DG Enabling Investments

The Distributed Generation Improvement Plan (DGIP) lays out an aggressive plan to enable the integration of significant amounts of new distributed resources, which are expected to be primarily rooftop PV. This plan calls for investments to enable "clearing the existing queue" within the next 18 months, and investments enabling total interconnected DGPV to reach 650MW (for O'ahu) by 2030. This will continue to provide our customers with an important option to manage their electricity costs and contribute to meeting State RPS goals.

The DGIP includes a Distribution Circuit Improvement Implementation Plan (DCIIP) that summarizes specific strategies and action plans, including associated costs and schedules, for circuit upgrades and other mitigation measures to increase the capacity of the Companies' electrical grids and enable the interconnection of additional DG.

In evaluating each company, by circuit and substation transformer, improvements to allow for greater interconnection of DG include: (1) updating LTC and voltage regulator controls to be capable of operating properly under reverse-flow conditions; (2) upgrading substation transformer capacity when load and DG are greater than 50% of capacity in the reverse direction; (3) upgrading primary circuit capacity when load and DG are greater than 50% of capacity in the reverse direction; (4) upgrading customer service transformer capacity when load and DG are greater than 100% of capacity, which also mitigates high voltage; (5) adding a grounding transformer to circuits when 33% of DML is exceeded for applicable circuits; and (6) adding a grounding transformer of 46-kV lines when 50% DML is exceeded. Each of these mitigation measures provides different values to both the utility and the distributed PV owner.

Smart Grid and Demand Response

At the Hawaiian Electric Companies, we are committed to achieving modern and fully integrated electric grids on each of the islands we serve—grids that harness advances in networking and information technology and, as a result, deliver tangible benefits to our customers and the state of Hawai'i. To accomplish this, we plan to invest in smart grid.

A smart grid modernizes our electrical grid enabling a more seamless integration of renewable energy, increasing reliability and efficiency, helping the environment, and lowering costs—all without compromising safety or the quality of electric service. In addition, the smart grid enables customers to make wiser choices that can guide their energy choices.

Please refer to our Smart Grid filing for more details about our smart grid roadmap.

Two-Way Communications System

The backbone of our Telecom System (fully owned by the Hawaiian Electric Companies) acts as an enabler for all of our operational and corporate business applications, including the smart grid applications. The Hawaiian Electric Companies enterprise telecommunications network or backbone is commonly referred to as our Wide Area Network (WAN) and Field Area Network (FAN). The smart grid applications and end devices (such as the smart meters), fault circuit indicators (FCIs), SCADA-enabled distribution line transformers and switches, reside in the Neighborhood Area Network (NAN), which is located beyond the WAN and FAN networks. The foundation of the smart grid platform (the NAN) we intend to implement is a two way communications network that connects points along the distribution grid to our back office software. Smart grid applications run on that network providing detailed information about the performance of the distribution grid.

AMI uses the secure IPv6 network that employs wireless 900MHz radio frequency mesh technology. This wireless technology consists of: access points; routers enabling devices communicating over the radio frequency mesh network to connect to our IT infrastructure through wired or cellular connections; relays, which are repeater devices that extend the reach of the radio frequency signal; and intelligent endpoints (such as third-party smart meters outfitted with network interface cards from Silver Spring Networks).

All Silver Spring Networks devices contain a one watt, two way radio. These devices connect with each other to form a mesh that makes up the Neighborhood Area Network (NAN). Access points and relays will be designed to have multiple paths through the NAN and the utility's WAN to provide high-performance, redundant connections between endpoints and our back office systems and data center. The network interface cards inside smart meters also act as relays (repeaters), further extending the mesh.

The radio frequency mesh network aggregates smart meter data and transmits it to us either through the utility-owned WAN or cellular connection. The mesh network can also transmit other information (such as remote service connects or disconnects) from us to customers. A back office head end system (such as UtilityIQ) collects, measures, and analyzes energy consumption, interval and time-of-use data, power quality measures, status logs and other metering data, and manages smart grid devices. Other back office systems manage meter data and integrate that data with customer and billing information.

Customer Engagement

Although this component represent a small portion of costs of Hawaiian Electric's Smart Grid program, the Hawaiian Electric Companies believe in a proactive, transparent and sustained communication effort to educate and engage our customers is critical to successfully rolling out our smart grid plans. Our efforts to engage our customers underscore our commitment to continually improve customer service, modernize the grid, and integrate renewable energy.

We intend to inform customers about installing smart meters, educate them about smart grid benefits, and address their related concerns. Key to this is helping customers understand that, at its core, smart grid technology will offer them more information about their energy use than ever before and give them tools and programs to help them control their energy use, which they can then use to help lower their electricity bills.

Through a multi-pronged approach for the duration of our smart grid roadmap, we intend to build interest from the onset, address questions and concerns, and engage customers in understanding the benefits of smart grid. Our communication program is based on tested and proven industry best practices, and is customized based on research conducted in this market on how to best reach our customers. Our approach seeks to engage our customers with information tailored to their specific needs and questions. Working with trusted third-party groups, we plan to engage customers in direct conversations wherever they are—at home, in their neighborhoods, and online.

Utility Scale Variable Renewable Generation

The Kahe Utility Photovoltaic (KPV) project will be designed to export up to 11.5MW (AC) of as-available photovoltaic generation to support the goal of reducing the use of fossil fuels and deliver auxiliary station power from a renewable resource.

Replacement Dispatchable Generation Capacity

Schofield

The SGS project will add approximately 50 MW of new flexible generation. The generating station will be capable of load following/peaking/cycling 10-minute reserve capacity generation consisting of six 8.4 MW multi-fuel capable reciprocating engine-generator sets and associated equipment. The project also will provide quick start dispatchable capacity that is capable of being started and fully loaded in 6 minutes or less. The engines will be capable of being individually started and dispatched to provide incremental capacity as needed. The project consists of construction of new generation as well as electrical transmission interties.

The generating station will be located on approximately 5 acres within property owned by the United States Army in Wahiawa, Oʻahu. This property is an undeveloped site with no established infrastructure. The SGS project will include a 2-mile aboveground 46kV transmission line connected to the existing Hawaiian Electric grid.

The project will provide grid-tied, firm, dispatchable, renewable generation to be installed on federal lands for the purpose of ensuring that the Army's critical national security and first responder missions can be carried on, particularly during events when the utility grid on O'ahu has been compromised, whether through a natural or man-made disaster. The federal lands would be leased at nominal cost from the Army in exchange for the commitment by the utility to construct, operate, maintain, and support the facility.

The electrical output from the SGS generators will normally supply power to all O'ahu customers through the O'ahu electrical grid. However, during outages that meet the criteria specified in an operating agreement with the Army, SGS output may be "islanded" to serve only the Army facilities at Schofield Barracks, Wheeler Army Air Field, and Field Station Kunia.

The SGS project will be capable of using gaseous and liquid fuels. 50% of the fuel used by the SGS engines will be the lowest-cost renewable fuel available at the time and the remainder of the fuel will be the lowest cost fuel available, whether renewable or not. The SGS will include black start capability in the event of a grid outage, allowing the facility to start-up independently, as well as provide black start capability to support the O'ahu grid when necessary.

New Generation

The Commission provided Hawaiian Electric explicit guidance to expeditiously "modernize the generation system to achieve a future with high penetrations of renewable resources." Decision and Order No. 32052, filed April 28, 2014, in Docket No. 2012-0036 (Regarding Integrated Resource Planning), Exhibit A: Commission's Inclinations on the Future of Hawai'i's Electric Utilities (*Commission's Inclinations*) at 4. The Commission recognized that act of "serving load" at all times of the day is becoming less focused on energy provision, and more focused on providing or ensuring the reliability of the grid. Proposed new, flexible generation projects would be a firm generation resource with attributes and optionality consistent with this guidance, including the following abilities:

- Start, synchronize to the grid, and ramp to full load in a few minutes;
- Ramp generation output up and down at fast rates for frequency regulation;
- Operate over a very wide range of loads when synchronized to the gird (that is, more than 12 to 1 turndown);
- Execute multiple starts and stops throughout any operating period;
- Control Volt-Amp Reactive (VAR) output for voltage regulation;
- Provide an automatic inertial response during major grid contingencies to help stabilize system frequency;
- Efficiently convert fuels to electric power (that is, to operate at low heat rates) over its full range of power output;

- Utilize multiple liquid and gaseous fuels; and
- Black start and "island a defined energy district" at a unique location in central O'ahu, adjacent to a major air field.

These attributes will contribute to increased grid stability, security, and resiliency as more variable renewable generation is interconnected.

Retirement of Existing Generation Assets

We will aggressively pursue the retirement and replacement of existing generating units. We deactivated Honolulu units 8 and 9 at the end of January 2014. These units were deactivated but are laid up in a manner that they could be returned to service in an emergency condition. Waiau units 3 and 4 are scheduled for deactivation in 2017. The deactivation of these units allows us to focus our existing resources on our existing units.

We intend to further retire/deactivate steam generating units as new generation and load situations allow. An aggressive plan for deactivation was created and can be adjusted as situations dictate. The plan includes deactivation of all steam units 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.

Units that are scheduled to be deactivated will require capital additions in order to prepare them for deactivation. This allows reactivation should it be required. The plans are very specific and be strictly adhered to in order to be in compliance with the environmental operating permits and regulations.

Use of the Honolulu, Waiau, and Kahe power plant sites after the existing units have been retired is very difficult to predict at this time. The current assumption is that the Waiau and Kahe sites will both have other active utility uses following the projected retirement of the units above, and so those sites are assumed to remain in active utility use.

The Honolulu Power Plant site however, excluding the adjacent substation site, is not anticipated to have a utility use following the retirement of units 8 and 9. While there are many unknowns that will impact both the potential use of this site and the value of the site, including the plans for an adjacent rail station and potential environmental remediation costs, the land is likely to have a net positive value. For the purposes of this financial analysis, it is assumed that the land would be sold in the year following unit retirement for $20M, net of any site remediation costs beyond the demolition and removal of the generating station.

FOUNDATIONAL INVESTMENTS

The success of the transformational investments discussed above is dependent on a strong foundation. The Company must continue to deliver safe, reliable, and efficient service to all customers. The foundational investments required to sustain operations are described below.

Asset Management

The Company has implemented a comprehensive asset management strategy to ensure the performance of the T&D grid. The asset management strategy systematically analyzes the characteristics and performance of each of the grid's major components, including:

- Performance of each major grid component
- Failure modes of each component
- Impact of failure for each component
- Replacement cost for each component

Based on these analyses, the Company has developed and implemented asset management strategies for each major component of the grid to cost effectively sustain the grid's performance over time.

An early assessment of the asset age and historical failure performance at Hawaiian Electric predicted that asset failures would significantly increase in the future unless Hawaiian Electric followed a more intensive approach to managing and replacing aging T&D assets. Failure to increase asset management efforts would result in increasing failures, degradation of electric service to Hawaiian Electric customers and significantly increasing costs as more of the O&M expenses and capital budget are required for corrective maintenance. Asset management (AM) is the process of managing utility assets with a balanced perspective of the company, customers, regulators and employees. It is an integrated set of processes used to minimize life-cycle asset costs while maintaining an acceptable level of risk and continuously delivering reliable service.

Assessing the risk posed by aging and/or problematic assets involves determining the failure probability and potential consequences of in-service failures. Probability of in-service failures is dependent on factors such as operating and maintenance history, but is heavily driven by age for many types of utility equipment. The probability of failure is typically low for most of the equipment's life and then increases dramatically as the equipment nears the end of its average life. As such, when a population of equipment ages the number of failures can increase significantly over time. Potential consequences of in-service failures are usually described in terms of safety, reliability, and cost impacts.

There are various strategies that can be used to address aging and/or problematic assets. These generally include replacing equipment 1) after it has failed in service ("run-to-failure"); 2) prior to failure based on observable indications of imminent failure ("run to imminent failure"); and 3) prior to in-service or imminent failure based on risk posed by the equipment ("preventive replacement"). The optimal strategy or combination of strategies can vary for different categories of equipment depending on factors such as forecasted failures, consequences of in-service failure, condition assessment effectiveness and cost, obsolescence, installation data, and new technology. Furthermore, spare equipment policies are generally developed along with replacement strategies to ensure that an adequate inventory is available when equipment failures do inevitably occur.

Hawaiian Electric's transmission, substation, and distribution infrastructure assets include equipment, such as distribution poles, circuit breakers, substation transformers, underground cable, transmission structures, distribution transformers and switchgear. These assets make up the system that delivers electricity to customers and typically last for many years before they eventually wear out or become obsolete and require replacement. Managing the replacement of aging and/or problematic assets is essential to maintaining the safety of employees and the public as well as the reliability of electric service provided to customers. Summaries of the strategies for these assets follow.

Distribution Poles

There are approximately 60,000 primary and secondary wood distribution poles on the system. The average age of these wood poles is about 40 years (expected life is 40-50 years) while the oldest wood poles on the system are over 90 years old. This is one of Hawaiian Electric's largest and most expansive asset classes. Wood poles in Hawaiian Electric's service area are under constant attack from moisture, insects, fungus, and termites. Approximately 700, or 6%, of the roughly 12,000 wood distribution poles inspected each year are identified as needing to be replaced. The failure rate is expected to increase as a higher number of wood poles reach and surpass the end of their useful life.

The recommendations for this asset class include:

- Continue the Test and Treat program on a five-year cycle to determine pole shell thickness and identify poles that need to be replaced or restored through life extension solutions such as C-Truss or ET-Truss pole reinforcement
- Continue installing "Termi-Mesh" stainless steel barriers to retard termite infestation on all new wood poles installed
- Replace between 1,100 and 1,500 wood distribution poles each year for the next 10 years (2014-2023) and a total of 13,000 poles over the same period

138 kV Circuit Breakers

There are approximately 125 circuit breakers on O'ahu's transmission system that operate at 138 kV. Of these, there are 47 oil circuit breakers and 78 SF6 gas circuit breakers. The oil circuit breakers range in age from 33 to 52 years old. The average age of these circuit breakers is 42 years while the expected life is around 60 years. The gas circuit breakers range in age from 1 to 29 years old. The average age of these circuit breakers is 15 years while the expected life is around 30 years. The likelihood of failure increases as units approach and exceed their average expected life.

Unexpected circuit breaker failures can potentially result in extended periods of operating the system in an abnormal condition; catastrophic failure and costly replacement of protected and nearby equipment; safety hazards to employees and the public; and major or system wide outages. Since 138 kV circuit breakers have an average procurement cycle of up to 28 weeks, adequate levels of spares must also be maintained.

The recommendations for this asset class include:

- Continued inspection and maintenance programs
- Identify and replace circuit breakers that are uneconomic to maintain or that are exhibiting characteristics indicative of imminent failure
- Replace a total of, at least, six generator synchronizing breakers during the period form 2014-2016
- Keep on-island spare inventory of four 138 kV circuit breakers

46 kV Circuit Breakers

There are approximately 130 circuit breakers on O'ahu's transmission system that operate at 46 kV. Of these, there are 62 oil circuit breakers and 68 SF6 gas circuit breakers. The oil circuit breakers range in age from 29 to 71 years old. The average age of these circuit breakers is 51 years while the expected life is around 60 years. The gas circuit breakers range in age from 1 to 27 years old. The average age of these circuit breakers is 8 years while the expected life is around 30 years. The likelihood of failure increases as units approach and exceed their average expected life.

Unexpected circuit breaker failures can potentially result in extended periods of operating the system in an abnormal condition; catastrophic failure and costly replacement of protected and nearby equipment; and safety hazards to employees and the public. Since 138 kV circuit breakers have an average procurement cycle of up to 28 weeks, adequate levels of spares must also be maintained.

The recommendations for this asset class include:

- Continued inspection and maintenance programs

- Identify and replace circuit breakers that are uneconomic to maintain or that are exhibiting characteristics indicative of imminent failure
- Complete previously planned proactive circuit breaker replacements for 2013 (five OCBs)
- Preventively replace one high-risk capacitor GCB with a "zero crossing" circuit breaker in 2014
- Preventively replace three high-risk line circuit breakers each year from 2014-2023
- Keep on-island spare inventory of three 46 kV line circuit breakers and one 46 kV capacitor bank ("zero crossing") circuit breaker

138 kV Substation Transformers

There are 31 substation power transformers, primarily rated at 138-46 kV 48/80 MVA. The average age of these transformers is about 30 years old while the expected life estimates range from 30 to 60 years. The oldest transformer in this asset category is 52 years old. Failures are forecasted to increase from about one every two years currently to one or more each year by 2019.

Unexpected transformer failures can potentially result in extended outages to customers; extended periods of operating the system in an abnormal condition; potential environmental incidents and expensive cleanup efforts if oil spills from the tank; extended overtime labor to restore the system; damage to nearby equipment in the substation; and a safety hazard to employees and the public. Since these transformers have an average procurement cycle of up to 92 weeks, adequate levels of spares must also be maintained.

The recommendations for this asset class include:

- Comprehensive inspection and maintenance program intended to maintain or extend the life of the transformers as well as identify and replace transformers exhibiting characteristics indicative of imminent failure
- Preventive replacement of two high-risk transformers in 2013 and one in 2014, then one every other year from 2015 through 2019, and then one each year through 2032
- Keep an on-island spare inventory of two spare 138-46 kV 48/80 MVA transformers to reduce the risk of not having emergency replacements

Distribution Substation Transformers

There are 210 distribution substation power transformers, primarily rated at 46-12 kV, 10 MVA and 12.5 MVA. The average age of these transformers is about 26 years old while the expected life estimates range from 30 to 60 years. The oldest transformer in this asset category is 63 years old. Failures are forecasted to increase from about one every two years currently to one or more each year by 2022.

Unexpected transformer failures can potentially result in extended outages to customers; extended periods of operating the system in an abnormal condition; potential environmental incidents and expensive cleanup efforts if oil spills from the tank; extended overtime labor to restore the system; damage to nearby equipment in the substation; and a safety hazard to employees and the public. Since these transformers have an average procurement cycle of 34-36 weeks, and could take up to 52 weeks in periods of high demand, adequate levels of spares must also be maintained.

The recommendations for this asset class include:

- Comprehensive inspection and maintenance program intended to maintain or extend the life of the transformers as well as identify and replace transformers exhibiting characteristics indicative of imminent failure
- Preventive replacement of three to four high-risk transformers per year going forward
- Keep an on-island spare inventory of two spare 46-12 kV 10/12.5 MVA, 8% impedance transformers and one spare 46-12 kV 10/12.5 MVA, 10% impedance transformer and one transformer that will be used to replace existing 46-12 kV 3.75/5/6.25 MVA transformers to reduce the risk of not having emergency replacements

Primary Underground Cable

There is approximately 4,362 conductor miles of underground primary distribution cable. Of this, about 4,085 conductor miles of this cable is in conduit while about 277 conductor miles of this cable is directly buried in the ground. Cable faults are one of Hawaiian Electric's top two system outage causes and cable faults are forecasted to nearly double in 10 years if only corrective replacements are made during that period. Increasing cable faults can result in decreased reliability and more customers experiencing multiple, often long service interruptions each year.

The recommendations for this asset class include:

- Increase primary underground cable preventive replacement rate, particularly for direct buried cable (increase to rate of 25 conductor miles direct buried cable and 90 conductor miles of cable in conduit per year)
- Continue the current practice of focusing replacements on the worst performing cable with an increased emphasis on customers experiencing multiple interruptions in a year
- Reactively replace paper-insulated lead cable (PILC) when it fails or as part of poorly performing laterals, circuits, or areas targeted for preventive cable replacement

- Collect additional data on cable replacements and cable faults to further refine analysis

138 kV Wood Transmission Structures

There are 374 wood pole transmission structures on 17 of Hawaiian Electric's 28 overhead 138 kV circuits. Wood pole structures make up 29% of all 138 kV transmission structures. The average age of wood pole structures on the 138 kV system is 47 years old while the oldest wood pole structures are 54 years old. Significant portion of Hawaiian Electric's wood pole structures is past or nearing their expected life of 50-55 years. The 138 kV transmission circuits are the backbone of Hawaiian Electric's system and the loss of a transmission circuit could, in the worst case scenario, lead to an island-wide blackout.

The recommendations for this asset class include:

- Continue the Test & Treat program on a 5-year cycle
- Perform energized climbing inspections on all 138 kV structures on a 6-year cycle
- Reactive repair or replacement of structures based on inspections and preliminary engineering and inspection results
- Preventive retirement of structures: At or before the target retirement age of its supported circuit and circuit criticality tier; and up to an additional five structures each year depending on other criticality factors
- Wood pole structures will be retired and replaced with steel pole structures where feasible and in accordance with the Hawaiian Electric Transmission Structural Design Policy

Distribution Transformers

There are over 32,000 distribution transformers installed on Hawaiian Electric's system. These include pad-mounted, pole-mounted, vault, Corten shell enclosed, and submersible transformers. The average age of the asset population is 18 years old while the average expected life is 20 to more than 35 years depending on the transformer type and housing material. About 15 percent, or 4,800, of the in-service distribution transformers were manufactured prior to 1980 and therefore could contain trace amounts of polychlorinated biphenyls (PCBs). In addition, about 248 of the in-service distribution transformers are Corten shell enclosed.

In-service failures of distribution transformers are typically not violent and usually affect only a small number of customers. There is concern about pad-mount transformers failing prematurely or posing safety risks due to corrosion; however, the extent of this issue is unknown as there is no inspection program in place.

In addition, based on EPA guidelines, there are a significant number of "PCB contaminated" (that is, unknown PCB content and pre-1980 manufacture date) transformers. Hawaiian Electric believes, along with other utilities, that regulations will change in the near future requiring removal of "PCB contaminated" equipment by 2025.

Corten shell enclosed transformers have specific operating and reliability issues, but comprise less than one percent of the total distribution transformer population

The recommendations for this asset class include:

- Generally run-to-failure and then replace
- Continue with the practice of using stainless steel construction for all distribution transformers
- Develop and initiate a routine pad-mount transformer inspection program to track the condition
- Preventive replacement of all pre-1980 distribution transformers by the end of 2024
- Preventive replacement of all Corten shell transformers with pad-mounted transformers by the end of 2020

15 kV Switchgear

There are 207 in-service 15 kV switchgear assemblies that house 418 draw-out type circuit breakers. The average age of these switchgears is about 27 years old while the expected life estimates range from 25 to 50 years. The oldest 15 kV switchgear in this asset category is 54 years old. The average age of these circuit breakers is about 23 years old while the oldest circuit breaker is 52 years old. Failures are forecasted to increase from about one every two years currently to one or more each year by 2019. Circuit breakers are, on average, younger than the switchgear assemblies due to the practice of replacing individual circuit breakers prior to replacing the entire switchgear assembly in many instances.

Unexpected switchgear failures can potentially result in extended outages to customers, damage and/or failure of equipment protected, loss of revenue, and, in rare cases, employee injury. Hawaiian Electric has experienced four catastrophic failures of 15 kv switchgear in the last six years resulting in customer interruptions and switchgear damage. The Company also experiences about six circuit breaker failures to trip or close each year due mostly to repeated failures of old breakers and typically resulting in a broader outage or delays in service restoration. Each year Hawaiian Electric replaces about one switchgear due to advanced housing corrosion.

The recommendations for this asset class include:

- Ongoing visual inspections of switchgear assemblies every six months and breaker maintenance every four years
- Continue with the practice of using stainless steel construction and other corrosion-resistant features for all new switchgear
- Preventive replacement of three switchgear assemblies per year through 2015, then six per year through at least 2032
- Switchgear replacements will be implemented in conjunction with replacement of 46-12 kV 10/12.5 MVA substation transformers where appropriate
- Distribution automation enabling of new 15 kV switchgear installations where appropriate
- On-going retention of six on-island 15 kV switchgear assemblies for reactive and preventive replacements

Asset management principles aim to minimize corrective replacement costs, both O&M expense and capital, by implementing preventive strategies. Work performed on a planned basis, in the normal course of business, can usually be executed at lower, more predictable, overall costs and with greater degree of safety to Hawaiian Electric employees and the public. Therefore, following a less aggressive approach would ultimately lead to an increase in cost.

Customer Connections (New Customers)

The Company will need to connect new customers throughout the 2015 – 2030 period. This work includes preparing the design and packaging of customer-requested work, such as overhead and underground services to new and existing customers along with related overhead and underground additions for construction and/or meter installations.

Customer Projects (Existing Customers)

The Company will need to complete customer projects throughout the 2015 – 2030 period.

This category of work includes preparing the design and relocations of services to existing customers for both overhead and underground services. The projects included in this category fall under the baseline category. Note -Fully Funded Customer Projects will not appear since numbers are net of CIAC.

Enterprise

Overview of IT Capital Programs and Enterprise Information Systems

The IT related Capital projects and programs projected in the 2015-2030 Capital forecast consists primarily of two categories:

1. IT Capital programs that support the Companies' hardware lifecycle and growth, broken down by IT function or IT service.
2. Enterprise Information Systems based on the Companies' Enterprise Information Systems (EIS) Roadmap (filed with the commission on 6/13/2014), which includes new software implementations, replacements and upgrades.

This document provides a high level overview of each category and their respective project and programs and the following table provides a view of the projects and programs over the specified timeline.

IT Programs

The ITS Department's capital budget consists primarily of IT hardware programs: (1) that maintain and enhance Hawaiian Electric's data center and network infrastructure; and (2) to provide the workforce with assets that support employee productivity and communications.

These programs are needed to maintain and improve upon IT service levels to both Company stakeholders as well as customers through the lifecycle replacement of hardware assets. In addition, the programs account for increased demand for reliable and secure access to information and information technology, primarily driven by (1) employee and facilities growth; (2) increased investment in mobile computing; (3) escalating need for cyber security and privacy; (4) increased need for enterprise content management; and (5) improved disaster recovery and reliability.

A brief description of each of the IT programs is provided below.

IT Infrastructure program: The IT Infrastructure program is needed to maintain and enhance Hawaiian Electric's data center and network infrastructure and includes costs to lifecycle the server fleet, networking equipment (routers and switches), and electronic storage, as required to meet the Company's business needs. The IT infrastructure program includes "ERP/CIS Hardware Upgrade" 2018-2030 costs (shown separately as an adjustment above for the purposes of this forecast) to accommodate projected replacement and growth specifically for Enterprise Server hardware needs.

Client Computing program: The Client Computing program is needed to provide the workforce with devices and other assets that are managed as part of the client computing environment and support employee productivity and communications. It includes costs to accommodate growth and lifecycle of that environment; including desktop PCs, laptops, mobile devices, and peripherals.

Collaborative Communications program: The Collaborative Communications program includes cost for those hardware assets that enable cost-effective communication and collaboration across time and distance. Specific examples include conferencing enabled telephones, projectors, electronic whiteboards, video conferencing devices, displays, digital signage equipment, microphones and public address (PA) equipment.

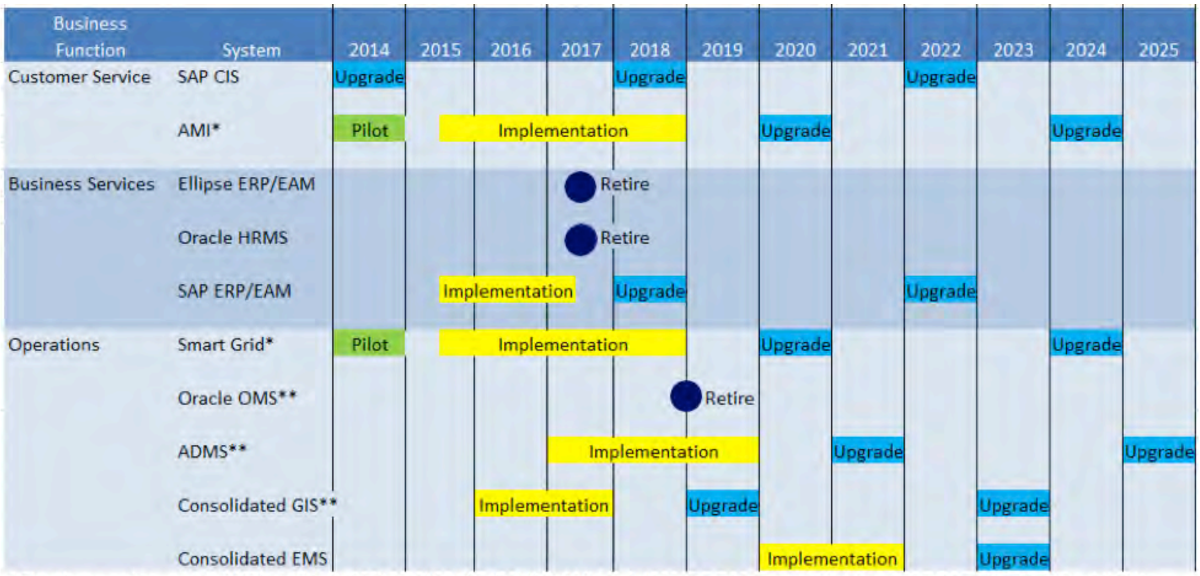
Copiers/Printers: The Copiers/Printers program includes costs to maintain, lifecycle replace, and net new additions for equipment that support the Company's printing and imaging needs. This includes desktop, multi-function, and wide-format printing devices, as well as imaging, scanning and fax devices.

(Miscellaneous) Telephone Equipment: The Telephone equipment program includes costs related to lifecycle and growth of the Company's telephone system including the PBX system, related telephony equipment, and office VOIP and digital phones.

(Miscellaneous) Office Equipment: The Office Equipment program includes costs for lifecycle replacement and installation of new equipment that support the Company mailing operations and general office equipment. Examples include the Company's mail inserter and folding machines used for billing purposes.

Enterprise Information Systems (EIS) Implementation and Upgrade Projects

EIS projects provided in this forecast include projects based on the EIS Roadmap, filed with the commission on 6/13/14.



* This document separates AMI from Smart Grid to reflect the fact that AMI provides customer consumption to customers and to the CIS, while the Smart Grid functions provide Operational capabilities.

** A study is underway to evalute an OMS upgrade or replacement with an ADMS. This document assumes OMS will be replaced by an ADMS. The study also evaluates GIS consolidation and standardizidation. This document assumes GIS consolidation. Additional phases for the ADMS and GIS will be added as they are better defined.

Figure K-1. EIS Implementation Plan

The EIS implementation and upgrade projects projected within the Capital forecast are based on the EIS Roadmap with minor adjustments to accommodate the capital forecasting process and adjustment for recent developments. These adjustments include:

1. Projected business releases within the overall GIS and ADMS projects.
2. The inclusion of a Demand Response Management System project.
3. The projection of upgrades through the additional 5 years of the forecast, not accounted for in the EIS roadmap, based on a 4 year average Enterprise Software upgrade cycle.
4. The "future software implementations" for years 2023 - 30 are based on average spend of years 2015-2022.
5. Smart Grid and AMI explanations will be provided separately, by the Smart Grid project team.

For the purpose of this overview these projects can be viewed in two categories: EIS projects and EIS upgrades. For a more detailed explanation of strategic and other drivers please reference the EIS roadmap. The following overviews are broken out between EIS implementation projects and upgrades.

EIS implementation Projects

ERP/EAM Project: The ERP/EAM project is a major current initiative in the Business Services area of our EIS Roadmap. For a detailed explanation of this project, please reference Dockets 2013-0007 and 2014-0170. The main goals of this effort are to address:

- **Technical Risk:** Replace Ellipse and many workgroup systems with an integrated modern solution. The currently installed Ellipse software and platform is technically obsolete, and continued use of the current version of Ellipse exposes the Companies to rapidly increasing levels of operating risk due to the technical obsolescence of the application software, system software and hardware on which it is dependent. Beyond 2017, there is a significant risk that the Ellipse system will become unsupportable.
- **Vendor Risk:** Implement a solution that is well supported within the utility industry today and into the foreseeable future. There is concern with the long-term vendor commitment to Ellipse. The newest version of Ellipse does not provide the level of electric utility-specific functionality necessary to meet the Companies' key current and future business challenges and opportunities.
- **Business Improvements:** Take the opportunity to improve business processes that increases productivity, efficiency and effectiveness.

EGIS Project: The Geographic Information System (GIS) provides the location of electrical facilities (poles, conductors, transformers, substations, etc.) on a map. It also stores information on how these facilities are connected together to make up the electrical grid. This allows for circuit tracing and allows for the export of this model to other applications such as the Outage Management System (OMS) for outage management and SynerGEE for power flow analysis. This project will migrate from the current multiple instances of different GIS platforms to a single Enterprise GIS solution, across all three companies. This effort includes cleansing and improving the accuracy of the location of electrical facilities.

ADMS Project: The Advanced Distribution Management System (ADMS) project will upgrade and expand the functionality of the current Hawaiian Electric's Outage Management System (OMS) which is used to determine and track electrical outages and deploys this system to across the three companies. An ADMS is comprised of three foundational features: Outage Management used to track and simulate outages; SCADA integration for receiving status and sending commands to the devices in the electrical grid; and Distribution Management System (DMS) which monitors and controls switching at the distribution level in conjunction with Distribution Automation.

Demand Response Management System: A DRMS provides an integrated management application for managing Demand Response programs and implementing demand response events on the distribution grid. Demand response (DR) balances customers' need for electricity with the utilities' responsibility to successfully operate the system. A well-conceived and well-managed portfolio of demand response programs provides cost-effective and useful ancillary services and capacity for grid operations. DR programs may be implemented by the utilities and/or through 3rd-party administrators.

O'ahu Facilities Capital Expenditures

Ongoing utility operations require efficient and effective business facilities infrastructure to meet customer and workforce needs. O'ahu capital expenditures for facilities are necessary to provide adequate administrative working space, support structures and accommodations for employees to perform their assigned tasks. It includes renovation of existing structures to meet the changing needs of the company and to extend the service life of the structures.

The foundational capital investments required to support these needs include routine investments for building facilities sustenance and a replacement office facility. The office facility investment specifically will replace a large number of office leases, which should result in long-term savings for customers.

Waiau 1 & 2 and Office Building

These buildings need facility improvements for more efficient use of space at the Waiau Power Plant and Waiau Base yard. This project would convert facilities no longer required for their current usage into administrative space, where possible.

Ward Office Renovation

The Ward Avenue building is over 60+ years old and no major renovations have been completed in over 20 years. There have been tremendous growth in technology and the way we need to work and function within our workspace is changing. Upgrading the facilities is essential to facilitating a more functional and productive workspace.

New Warehouse

With the growth in employees, support that goes with the growth also increases. The Ward Base yard is congested with vehicles and warehouse activity and is becoming a safety issue. Plans are to alleviate the congestion by relocating some of the warehouse functions co-located with the base yard off of the Ward property.

System Operation Control Center (SOCC) Facility

A new SOCC facility is planned as a new control center for grid operations. The SOCC is planned to house the new EMS, ADMS, OMS and other grid operating infrastructure In light of recent updates to storm and tsunami maps and greater awareness of man-made threats, the new SOCC design and location will provide enhanced physical security from criminal/terrorist attacks as well as protection from natural disasters.

Office Building

The need for office space has increased with expanded staff and workload. There is no room for growth in the Hawaiian Electric-owned buildings (including power plants and the auxiliary base yards) as currently configured. Hawaiian Electric administrative staff is currently scattered in multiple leased locations: the main King St. Office building, the Central Pacific Bank Building, the American Savings Bank Tower, Pauahi Tower and Pacific Park Plaza. In particular, the main King St. office building is a leased building whose aging infrastructure as a national historic registered building is increasingly costly to maintain. Consolidating our office space currently scattered in different leased buildings will reduce costs, improve return on investment, reduce the existing inefficiencies caused by scattered facilities locations and overcrowding, and result in customer savings.

Reliability

The Reliability category covers projects to ensure that Hawaiian Electric's transmission and Distribution grids are available to accept generation resources and reliably deliver power to customers. A significant component to the Reliability theme includes distribution automation projects and programs. Some of the major programs include Distribution Automation programs, replacement of the Waiau 138kV and 46kV switchyards and substations, rehabilitation of the Halawa 138kV substation, and additional distribution substation projects to provide additional backup and transfer capabilities current loads in specific areas of the island.

Safety, Security, and Environmental

The Safety, Security, and Environmental theme is to ensure that Hawaiian Electric's transmission and distribution facilities and operations are in compliance with applicable environmental, safety and other regulations or, to ensure that such facilities and operations are in line with industry best practices if specific regulations do not exist. For example, related to seabird protection under the Endangered Species and Migratory Bird Treaty Acts, Hawaiian Electric started installing "bird friendly" lighting at Hawaiian Electric's facilities.

Archer Substation 46kv GIS Replacement

The primary purpose of this project is to design and install replacement 46kv GIS equipment at the Archer Substation. There have been serious injuries and fatalities associated with the specific model and vintage of GIS equipment (including serious injury of Hawaiian Electric employees) currently installed at Archer Substation. In addition, the manufacturer has discontinued full support of this line of equipment which will have an impact to the availability and timeliness of parts to support continued operations.

MATS Compliance

Emissions standards set under the toxics program are federal air pollution limits that individual steam power plant facilities must meet by 2016.

FOUNDATIONAL CAPITAL INVESTMENT PROJECT DESCRIPTIONS

This section describes the capital investment projects.

Asset Management

Ala Wai Canal 46kV U Relocation

The purpose of this project is to increase the reliability of the Waikiki Substation by permanently relocating the Pukele 5 and Kamoku 43 46kV feeders crossing the Ala Wai Canal to a new alignment along Ala Wai Blvd running from Kapahulu Substation to Waikiki Substation. After the relocation is completed, the existing two 46kv cables can be removed from the canal. State DLNR letter of 9/25/2003 to Hawaiian Electric requires that the cables be permanently relocated.

Kahe Transfer#1 80MVA P/I

The purpose of this project is to retire the existing Kahe 138–46kV, 80 MVA Transformer #1 and purchase and install a new 138–46kV, 48/64/80 MVA transformer to improve the reliability of the transmission system.

Koʻolau Transfer#1 80MVA P/I

Replace existing 138–46kV, 80 MVA Transformer No. 1 and purchase and install a new 138kV 80 MVA transformer. The purpose of this project is to retire the existing Koʻolau 138–46kV 80 MVA Transformer #1 and purchase and install a new 138–46kV, 48/64/80 MVA transformer.

Koʻolau Transfer#3 80MVA P/I

The purpose of this project is to retire the existing Koʻolau 138–46kV, 80 MVA Transformer #3 and purchase and install a new 138–46kV, 48/64/80 MVA transformer.

Pukele 80MVA Transfer #1

At the Pukele 138kV substation, the Pukele transformer #1 is scheduled to be proactively retired and a new 48/80 MVA transformer will be purchased and installed in its place as part of the Asset Management Plan.

Pukele 80MVA Transfer #2

At the Pukele 138kV substation, the Pukele transformer #1 is scheduled to be proactively retired and a new 48/80 MVA transformer will be purchased and installed in its place as part of the Asset Management Plan.

Wahiawa Transfer#1 80MVA P/I

The purpose of this project is to retire the existing Wahiawa 138–46kV, 80 MVA Transformer #1 and purchase and install a new 138–46kV, 48/64/80 MVA transformer.

Waiau Transfer A 80MVA P/I

Retire the existing Waiau 138–46kV 80 MVA Transformer A and purchase and install a new 138–46kV, 48/64/80 MVA transformer.

Waiau Transfer B 80MVA P/I

The purpose of this project is to retire the existing Waiau 138–46kV, 80 MVA Transformer B and purchase and install a new 138–46kV, 48/64/80 MVA transformer.

Customer Connections

Kalaeloa Substation

The purpose is to address increasing load demand by installing a new system substation in the Kalaeloa area.

Ph1–Waipahu SS T&D

Install capacity in various substations and T&D facilities to serve the City's Honolulu High Capacity Transit Corridor Project (HHCTCP). These projects are required to serve facilities for the West Oʻahu/Farrington Highway (WOFH) Guideway Segment of the Honolulu Rail Transit Project.

Ph1–Waipahu SS Transfer #3

Install capacity in various substations and T&D facilities to serve the City's Honolulu High Capacity Transit Corridor Project (HHCTCP). These projects are required to serve facilities for the West O'ahu /Farrington Highway (WOFH) Guideway Segment of the Honolulu Rail Transit Project.

Ph2–Pearl City SS T&D

These projects are required to serve facilities for the Kamehameha Highway Guideway Segment (KHG) segment of the Honolulu Rail Transit Project. The purpose of this project is to install a dedicated substation to provide electrical service to meet the estimated loads as requested by the City & County of Honolulu Rapid Transit Authority (HART).

Ph2–Pearl City SS Transfer #2

These projects are required to serve facilities for the Kamehameha Highway Guideway Segment (KHG) segment of the Honolulu Rail Transit Project. The purpose of this project is to install a dedicated substation to provide electrical service to meet the estimated loads as requested by the City & County of Honolulu Rapid Transit Authority (HART).

Ph3–Aiea for Stadium TS

These projects are required to serve facilities for the Airport Guideway Segment of the Honolulu Rail Transit Project. The scope of work includes relocation of Hawaiian Electric electrical facilities and installation of distribution infrastructure to serve new facilities for the Rail Transit stations in the Airport Guideway Segment, which runs from Aloha Stadium through Middle Street.

Ph3–Keehi for Airport TS

These projects are required to serve facilities for the Airport Guideway Segment of the Honolulu Rail Transit Project. The scope of work includes relocation of Hawaiian Electric electrical facilities and installation of distribution infrastructure to serve new facilities for the Rail Transit stations in the Airport Guideway Segment, which runs from Aloha Stadium through Middle Street.

Ph3–Lagoon for Lagoon TS

These projects are required to serve facilities for the Airport Guideway Segment of the Honolulu Rail Transit Project. The scope of work includes relocation of Hawaiian Electric electrical facilities and installation of distribution infrastructure to serve new facilities for the Rail Transit stations in the Airport Guideway Segment, which runs from Aloha Stadium through Middle Street.

Ph4–Hon for Chinatown TS

These projects are required to serve new facilities for the City Center Guideway Segment of the Honolulu Rail Transit Project. The purpose of this project is to install a dedicated substation to provide electrical service to meet the estimated loads as requested by the City & County of Honolulu Rapid Transit Authority (HART).

Ph4–Kakaako for Civic TS

These projects are required to serve new facilities for the City Center Guideway Segment of the Honolulu Rail Transit Project. The purpose of this project is to install a dedicated substation to provide electrical service to meet the estimated loads as requested by the City & County of Honolulu Rapid Transit Authority (HART).

Ph4–Kewlo for Ala Moana TS

These projects are required to serve new facilities for the City Center Guideway Segment of the Honolulu Rail Transit Project. The purpose of this project is to install a dedicated substation to provide electrical service to meet the estimated loads as requested by the City & County of Honolulu Rapid Transit Authority (HART).

Ph4–Lagoon for Midd St TS

These projects are required to serve new facilities for the City Center Guideway Segment of the Honolulu Rail Transit Project. The purpose of this project is to install a dedicated substation to provide electrical service to meet the estimated loads as requested by the City & County of Honolulu Rapid Transit Authority (HART).

Enterprise IT Framework

ADMS BR1 – OMS Core Functionality Capital

Replaces the current Outage Management System (OMS) at Hawaiian Electric which will become unsupportable in 2016 (based on Hardware/OS losing vendor support). This project also deploys OMS functionality to Maui Electric and Hawaiian Electric Light.

ADMS BR1 – OMS Core Functionality Deferred

Replaces the current Outage Management System (OMS) at Hawaiian Electric which will become unsupportable in 2016 (based on Hardware/OS losing vendor support). This project also deploys OMS functionality to Maui Electric and Hawaiian Electric Light.

Client Computing

The Client Computing program is needed to provide the workforce with devices and other assets that are managed as part of the client computing environment and support employee productivity and communications. It includes costs to accommodate growth and lifecycle of that environment; including desktop PCs, laptops, mobile devices, and peripherals.

ERP/EAM Capital

The ERP/EAM project is a major current initiative in the Business Services area of our Enterprise Information System (EIS) Roadmap. For a detailed explanation of this project, please reference Dockets 2013–0007 and 2014–0170. The main goals of this effort are to address technical risk, vendor risk and business improvements.

ERP/EAM Deferred

The ERP/EAM project is a major current initiative in the Business Services area of our Enterprise Information System (EIS) Roadmap. For a detailed explanation of this project, please reference Dockets 2013–0007 and 2014–0170. The main goals of this effort are to address technical risk, vendor risk and business improvements.

Future software implementations Capital

The projection of upgrades through the additional 5 years of the forecast, not accounted for in the EIS roadmap, based on a 4 year average Enterprise Software upgrade cycle. The "future software implementations" for years 2023 – 30 are based on average spend of years 2015–2022. This portion is for the hardware component of the anticipated projects. For a more detailed explanation of strategic and other drivers please reference the EIS roadmap.

Future software implementations Deferred

The projection of upgrades through the additional 5 years of the forecast, not accounted for in the EIS roadmap, based on a 4 year average Enterprise Software upgrade cycle. The "future software implementations" for years 2023 – 30 are based on average spend of years 2015–2022. This portion is for the hardware component of the anticipated projects. For a more detailed explanation of strategic and other drivers please reference the EIS roadmap.

IT Infrastructure

The IT Infrastructure program is needed to maintain and enhance Hawaiian Electric's data center and network infrastructure and includes costs to lifecycle the server fleet, networking equipment (routers and switches), and electronic storage, as required to meet the Company's business needs. The IT infrastructure program includes "ERP/CIS Hardware Upgrade" 2018–2030 costs (shown separately as an adjustment above for the purposes of this forecast) to accommodate projected replacement and growth specifically for Enterprise Server hardware needs.

Facilities

Ctrl Baseyard & Warehouse Fac

Construct a new baseyard and warehouse facility to improve T&D operational efficiencies and address future growth in Energy Delivery operations.

New SOCC – Construction

A new SOCC is proposed for the enhancement of operational situation awareness and centralized control existing utility equipment, distributed energy resources and transitional technology systems that will be necessary for the integration of more renewable resources.

New SOCC – Land

A new SOCC is proposed for the enhancement of operational situation awareness and centralized control existing utility equipment, distributed energy resources and transitional technology systems that will be necessary for the integration of more renewable resources.

Waiau 1/2

The need for office space has increased with the growing number of employees. There is no room for growth in Company–owned buildings (including power plants and the auxiliary baseyards) as currently configured. Consolidating our office leases scattered in six different leased buildings will increase operational efficiencies and flexibility for our present and future workforce.

Office Building

The company currently leases a significant amount of administrative (office) space and desires to reduce overall expenditures by purchasing an office building in the future.

Ward Office Renovation

The building is over 60+ years old and no major renovations have been completed in over 20 years. There has been tremendous growth in technology and the way we need to work and function within our workspace is changing. Upgrading the facilities is essential to facilitating a more functional and productive workspace.

New Warehouse

With the growth in employees, support that goes with the growth also increases. The Ward Baseyard is congested with vehicles and warehouse activity and it is becoming a safety issue. Plans are to alleviate the congestion by relocating some of the warehouse functions off of the Ward Baseyard property.

Reliability

46kV Mobile Substation

The purpose of the project is to purchase a 46kV–12kV/4kV Mobile Substation. The objective of this project is to improve reliability of the distribution system.

DA–Smart Tech Install

Maintain and improve distribution reliability in the Waikiki area.

Dist Automation–Ena

Maintain and improve distribution reliability in the Waikiki area.

Dist Automation–Kapahulu

Maintain and improve distribution reliability in the Waikiki area.

Dist Automation–Kuhio

Maintain and improve distribution reliability in the Waikiki area.

Dist Automation–Waikiki

Maintain and improve distribution reliability in the Waikiki area.

Hal Bkr#176,4436,4492 P/I

The purpose of the Halawa Substation Rehabilitation project is to increase the reliability of the Halawa substation by eliminating 138 kV line crossings in the adjacent area, as well as upgrading the aging substation equipment, relays, controls, and communications.

Halawa 138kv Expansion

The purpose of the Halawa Substation Rehabilitation project is to increase the reliability of the Halawa substation by eliminating 138 kV line crossings in the adjacent area, as well as upgrading the aging substation equipment, relays, controls, and communications.

Halawa 46 kV Bus OH to UG

The purpose of the Halawa Substation Rehabilitation project is to increase the reliability of the Halawa substation by eliminating 138 kV line crossings in the adjacent area, as well as upgrading the aging substation equipment, relays, controls, and communications.

Halawa Bkr#157–159 138kV P/I

The purpose of the Halawa Substation Rehabilitation project is to increase the reliability of the Halawa substation by eliminating 138 kV line crossings in the adjacent area, as well as upgrading the aging substation equipment, relays, controls, and communications.

Halawa Bkr#160–162 138kV P/I

The purpose of the Halawa Substation Rehabilitation project is to increase the reliability of the Halawa substation by eliminating 138 kV line crossings in the adjacent area, as well as upgrading the aging substation equipment, relays, controls, and communications.

Halawa Comm Equipment P/I

The purpose of the Halawa Substation Rehabilitation project is to increase the reliability of the Halawa substation by eliminating 138 kV line crossings in the adjacent area, as well as upgrading the aging substation equipment, relays, controls, and communications.

Halawa Control House P/I

The purpose of the Halawa Substation Rehabilitation project is to increase the reliability of the Halawa substation by eliminating 138 kV line crossings in the adjacent area, as well as upgrading the aging substation equipment, relays, controls, and communications.

Halawa Switch Replacements

The purpose of the Halawa Substation Rehabilitation project is to increase the reliability of the Halawa substation by eliminating 138 kV line crossings in the adjacent area, as well as upgrading the aging substation equipment, relays, controls, and communications.

Halawa Transfer #1 80MVA P/I

The purpose of the Halawa Substation Rehabilitation project is to increase the reliability of the Halawa substation by eliminating 138 kV line crossings in the adjacent area, as well as upgrading the aging substation equipment, relays, controls, and communications.

Halawa Transfer #2 80MVA P/I

The purpose of the Halawa Substation Rehabilitation project is to increase the reliability of the Halawa substation by eliminating 138 kV line crossings in the adjacent area, as well as upgrading the aging substation equipment, relays, controls, and communications.

Hal–Iwi 138 kV Line

The purpose of the Halawa Substation Rehabilitation project is to increase the reliability of the Halawa substation by eliminating 138 kV line crossings in the adjacent area, as well as upgrading the aging substation equipment, relays, controls, and communications.

Halawa–Ko'olau #1 138 kV Pole Replacement

The purpose of the Halawa Substation Rehabilitation project is to increase the reliability of the Halawa substation by eliminating 138 kV line crossings in the adjacent area, as well as upgrading the aging substation equipment, relays, controls, and communications.

Halawa–Ko'olau #2 138 kV Line

The purpose of the Halawa Substation Rehabilitation project is to increase the reliability of the Halawa substation by eliminating 138 kV line crossings in the adjacent area, as well as upgrading the aging substation equipment, relays, controls, and communications.

Halawa–Ko'olau #3 138 kV Line

The purpose of the Halawa Substation Rehabilitation project is to increase the reliability of the Halawa substation by eliminating 138 kV line crossings in the adjacent area, as well as upgrading the aging substation equipment, relays, controls, and communications.

Halawa–Makiki 138 kV Line

The purpose of the Halawa Substation Rehabilitation project is to increase the reliability of the Halawa substation by eliminating 138 kV line crossings in the adjacent area, as well as upgrading the aging substation equipment, relays, controls, and communications.

Halawa–Sch 138 kV Line

The purpose of the Halawa Substation Rehabilitation project is to increase the reliability of the Halawa substation by eliminating 138 kV line crossings in the adjacent area, as well as upgrading the aging substation equipment, relays, controls, and communications.

New Waiau 46kv Substation

The purpose of this project is to build a new 46kV substation and control house to replace the existing Waiau 46kv Substation. With a new 46kv substation and control house, the reliability of transmitting power to the central Oʻahu region will be improved as the existing substation is in need of major upgrades to continue reliable operation.

North South Road 46kV/12kV Ln

To serve for the proposed East Kapolei II Sub–Division, which includes 1,500 residential homes and low density apartment units, the new KROC Center, a new middle school, and a new elementary school. In addition, the project will also provide provisions to service initial loads in the areas surrounding East Kapolei II.

North South Road Communication Links

To serve for the proposed East Kapolei II Sub–Division, which includes 1,500 residential homes and low density apartment units, the new KROC Center, a new middle school, and a new elementary school. In addition, the project will also provide provisions to service initial loads in the areas surrounding East Kapolei II.

North South Road Substation

To serve for the proposed East Kapolei II Sub–Division, which includes 1,500 residential homes and low density apartment units, the new KROC Center, a new middle school, and a new elementary school. In addition, the project will also provide provisions to service initial loads in the areas surrounding East Kapolei II.

Waiau 138KV SS Switch & Steel Replacement

The purpose of this project is to retire and replace severely deteriorated steel frames at Waiau 138 kV substation which support switches and strain bus. The project also includes the replacement of (10) GOAB 138 kV switches.

Waikiki–Halawa #1 138 kV Line

The purpose of the Halawa Substation Rehabilitation project is to increase the reliability of the Halawa substation by eliminating 138 kV line crossings in the adjacent area, as well as upgrading the aging substation equipment, relays, controls, and communications.

Waikiki–Halawa #2 138 kV Line

The purpose of the Halawa Substation Rehabilitation project is to increase the reliability of the Halawa substation by eliminating 138 kV line crossings in the adjacent area, as well as upgrading the aging substation equipment, relays, controls, and communications.

Safety, Security and Environmental

Archer Substation 46kV GIS Replacement

To design and install replacement 46kV GIS equipment at the Archer Substation. Due to age and recent reliability issues, and availability of parts, the GIS equipment will be replaced.

MATS Compliance

The purpose of the MATS Compliance projects are to provide the necessary upgrades at the Kahe and Waiau Power Plants to support compliance with the EPA's Mercury and Air Toxics Standards (MATS).

TRANSFORMATIONAL CAPITAL INVESTMENT PROJECT DESCRIPTIONS

DG Enabling Investments

DGIP / Distribution Transformers

The DGIP includes a Distribution Circuit Improvement Implementation Plan (DCIIP) that summarizes specific strategies and action plans, including associated costs and schedules, for circuit upgrades and other mitigation measures to increase the capacity of the Companies' electrical grids and enable the interconnection of additional DG. The DGIP also considers prioritization of the proposed mitigation actions to focus on the immediate binding constraints for interconnection of additional DG; analysis of the costs and benefits of proposed mitigation strategies and action plans; discussion of how distribution system design criteria and operational practices could be modified to enable interconnection of additional DG; and proposals for addressing the cost allocation issues that determine who bears responsibility for system upgrade costs.

Technology Demonstration

The Program is structured to evaluate technologies and applications that require field testing, and as such, leverages funding for battery or flywheel systems by outside entities to reduce technical risk. The technical value to field–test grid solutions at the substation level under an aggregated scenario will provide the Companies with operating experience and field data to guide its business decisions related to future commercial implementation.

Liquefied Natural Gas (LNG)

LNG

In an effort to reduce cost of electricity to the customer and comply with requirements of EPA's air regulations, Mercury and Air Toxics Standards (MATS) and National Ambient Air Quality Standards (NAAQS) by displacing liquid petroleum fuel with LNG. The ability to combust liquid petroleum fuel will be retained to enhance the flexibility and reliability of the units.

Pearl Harbor Substation

To install a new 46–12kV distribution substation to serve the future liquefied natural gas (LNG) docking station in Pearl Harbor.

Facilitates New and Renewable Energy

Flexible Operations

The Operational Flexibility Upgrade projects will increase unit operational flexibility in the areas of lower unit minimums, unit dynamic response, improved heat rate at the lower load profiles, minimize equipment degradation, & provide for seasonal cycling operation. These projects will improve equipment and facilities to support Kahe and Waiau power plant unit's operating profile to allow the grid system to accept increased amounts of intermittent renewable energy.

New System 138kV Line

A new 138kV transmission line from Koʻolau Substation to Wahiawa Substation (along the windward, northern, and central areas of the island) would accommodate additional renewable energy in the future on the central and northern areas of Oʻahu. This transmission line would be approximately 55 miles. Currently, no transmission circuits exist on this part of the island.

Replace Dispatch Gen Capacity

Schofield Generating Station

The proposed Schofield Generation Station project would provide about 50 MW of firm quick–start renewable capacity to be built upon Army provided land. The additional capacity will improve system reliability, provide fast start (8–minute) dispatchable capacity, and the large (10–17MW per unit) bio–fueled engines will allow economic dispatch by starting individual units, providing incremental capacity as needed.

Smart Grid and Demand Response

Smart Grid

The Smart Grid Full Implementation Project will 1) install devices in the field, such as meters, remote controllable switches, fault circuit indicators, capacitors, and load controlling switches, 2) install central office software designed to collect information from the field devices and/or then execute commands or tasks by a system operator for the purposes of managing the grid or managing the utilities' meter reading and field services business processes and 3) provide the Hawaiian Electric Companies' customers with tools which enables them to understand and manage their energy use and energy bill. The benefits for implementing the Smart Grid Full Implementation Project is to 1) lower electricity bills through savings and productivity improvements in utility operations, 2) increase renewable energy through integrated distributed generation, 3) provides tools to the customers to enable them to utilize their energy more effectively/efficiently, and 4) increase reliability through outage notification and distribution automation which can lower SAIFI and CAIDI.

Security System Investments

EMS – Capital

A new EMS using a common vendor platform for all utilities will provide operational efficiencies and support flexibility among the three utilities. The new system should be designed to enable future enhancement opportunities to provide backup and emergency support, manage the system changes and growing demands of renewable energy integration, respond and coordinate system emergencies across utilities.

EMS – Deferred

A new EMS using a common vendor platform for all utilities will provide operational efficiencies and support flexibility among the three utilities. The new system should be designed to enable future enhancement opportunities to provide backup and emergency support, manage the system changes and growing demands of renewable energy integration, respond and coordinate system emergencies across utilities.

PSIP Storage Contingency

200 MW battery energy storage system that provides contingency reserve for the grid.

PSIP Storage Load Shift

100MW battery energy storage system that provides regulating reserve for the grid.

TMP – DR Community Projects

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP – Frequent Purchase for Coll Point

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Central Waiau Switching Station 46/12kv

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Central – Airport Substation

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Central – Airport Switching Substation

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Central – Archer Substation

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Central – Halawa Baseyard

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Central – Honolulu Power Plant

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Central – Makalapa Substation

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Central – School Street Substation

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Central– Kahe Switching Station (5–8)

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Central–Iwilei Sub 138/25

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Center Airport Substation Airport Switch F/O

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Core – American Savings

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Core – Grosvenor

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Core – Kahe Power Plant

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Core – Waiau Power Plant

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Core – Ward Avenue

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Core Aina Koa–Pukele F/O

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Core Archer–Honolulu Club F/O

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Core ASB–CPP F/O

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Core Honolulu Club – King F/O

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Core HPP–ASB F/O

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Core HPP–Iwiilei138 F/O

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Core Kahe to CEIP F/O

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Core Kamoku–Aina Koa F/O

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Core King – Ward F/O

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Core King to CPP F/O

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP East – Halawa Substation

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP East – Kamoku Substation

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP East – Kewalo Substation

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP East – Ko‘olau Substation

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP East – Marketplace to Halawa F/O

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP East – Pi‘ikoi Substation

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP East – Pukule Substation

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP East Archer–Pi‘ikoi F/O

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP East Kamoku Upper F/O

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP East Pi‘ikoi to Ward F/O

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Edge – AES Power Plant

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Edge – Archer–HPP F/O

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Edge – Central Pacific Plaza

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Edge – Halawa Control Center

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Edge – Honolulu Club Building

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Edge – Kalaeloa Power Plant

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Edge – King Street Office

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Edge – Pauahi Tower

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Edge – Waterhouse

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP West – AES Substation

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP West – CEIP Substation

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP West – Chevron

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP West – CIP Power Plant

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP West – HRRV

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP West – Kalaeloa Substation

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP West Kahe Switching Station (1–4)

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Central Airport Switch Spl–Airport Substation F/O

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

Waiau–Makalapa Fiber Project

To expand the capacity of and provide an alternate route for the fiber optic communications between the Waiau Power Plant and Makalapa Substation. The objective of this project is to maintain and/or improve the reliability of Hawaiian Electric's Communication Infrastructure that supports Hawaiian Electric's Electrical System.

Utility Scale Variable Renewable Generation

K0–Kahe Utility Scale PV

The Kahe Utility Photovoltaic (KPV) project will be designed to export up to 11.5MW (AC) of as–available photovoltaic generation to support the goal of reducing the use of fossil fuels and deliver auxiliary station power from a renewable resource.

CAPITAL EXPENDITURES BY CATEGORY AND PROJECT

Capital Expenditures: 2015–2019

Table K-1 lists the budgeted, annualized dollar amount for each project; with totals by project group and by category, for the years 2015–2019. Table K-2 lists the budgeted, annualized dollar amount for each project; with totals by project group and by category, for the years 2020–2030 with project totals.

Project	2015	2016	2017	2018	2019
Foundational	**313,409,173**	**334,541,490**	**321,205,103**	**371,986,407**	**361,183,387**
Asset Management	120,178,088	141,000,928	158,458,491	172,268,487	152,939,160
Ala Wai Canal 46kV U Relocation	430,776	499,060	174,044	19,231,980	639,627
Kahe Transfer #1 80MVA P/I	–	–	32,679	416,813	3,143,702
Ko‘olau Transfer #1 80MVA P/I	–	–	–	773,348	1,066,632
Ko‘olau Transfer #3 80MVA P/I	–	–	–	–	–
Pukele 80MVA Transfer #1	3,122,628	–	–	–	–
Pukele 80MVA Transfer #2	40,556	–	–	–	–
Wahiawa Transfer #1 80MVA P/I	–	–	–	–	19,860
Waiau Transfer A 80MVA P/I	116,212	2,722,464	562,973	–	–
Waiau Transfer B 80MVA P/I	–	83,787	1,520,062	1,442,910	608,973
Baseline	116,467,916	137,695,617	156,168,733	150,403,435	147,460,366
Customer Connections	26,416,464	25,557,171	25,578,984	26,078,324	33,382,115
Kalaeloa Substation	–	–	133,227	356,302	9,276,583
Ph1–Waipahu SS T&D	420,645	65,383	–	–	–
Ph1–Waipahu SS Transfer #3	932,513	393,595	–	–	–
Ph2–Pearl City SS T&D	–	3,983	13,886	39,130	–
Ph2–Pearl City SS Transfer #2	–	3,368	7,144	33,072	–
Ph3–Aiea for Stadium TS	–	3,368	7,094	37,993	–
Ph3–Keehi for Airport TS	–	857	1,664	1,641	420
Ph3–Lagoon for Lagoon TS	–	643	1,694	1,636	560
Ph4–Hon for Chinatown TS	–	–	25,272	141,345	55,114
Ph4–Kakaako for Civic TS	–	–	22,334	130,738	68,670
Ph4–Kewlo for Ala Moana TS	–	–	16,457	109,523	95,783
Ph4–Lagoon for Midd St TS	–	1,231	43,310	162,560	14,446
Baseline	25,063,306	25,084,743	25,306,903	25,064,384	23,870,539
Customer Projects	1,907,213	8,338,410	(4,450,772)	2,655,251	1,902,013
Baseline	1,907,213	8,338,410	(4,450,772)	2,655,251	1,902,013

Project	2015	2016	2017	2018	2019
Enterprise IT Framework	29,386,540	32,961,548	12,936,217	14,795,051	12,656,461
ADMS BR1 – OMS Core Functionality Capital	–	–	176,400	–	–
ADMS BR1 – OMS Core Functionality Deferred	–	–	2,381,038	2,562,157	–
Client Computing	2,570,982	2,248,536	2,353,297	2,469,314	2,591,051
ERP/EAM Capital	2,590,000	–	–	–	–
ERP/EAM Deferred	19,300,000	24,710,000	1,140,000	–	–
Future Software Implementations Capital	–	–	–	–	–
Future Software Implementations Deferred	–	–	–	–	–
IT Infrastructure	3,083,983	2,888,867	2,966,061	3,112,288	3,265,724
Baseline	1,841,575	3,114,145	3,919,421	6,651,293	6,799,686
Facilities	8,380,626	6,129,488	6,656,905	7,573,291	10,285,797
Ctrl Baseyard & Warehouse Facility	–	–	–	–	288,776
New SOCC – Construction	–	–	–	–	–
New SOCC – Land	–	–	–	–	–
Waiau ½	–	–	–	–	502,000
Office Building	–	–	–	–	–
Ward Office Renovation	–	–	–	–	–
New Warehouse	–	–	–	–	–
Baseline	8,380,626	6,129,488	6,656,905	7,573,291	9,495,021
Reliability	103,925,059	108,716,252	103,595,899	128,188,790	139,779,311
46kV Mobile Substation	–	2,469,465	–	–	–
DA–Smart Tech Installation	–	735,544	1,099,748	528,744	–
Dist Automation–Ena	–	872,893	1,086,414	332,515	–
Dist Automation–Kapahulu	–	895,170	1,077,050	327,136	–
Dist Automation–Kuhio	–	10,325	40,534	2,197,986	–
Dist Automation–Waikiki	–	858,698	1,107,011	321,100	–
Hal Bkr#176,4436,4492 P/I	–	–	–	–	–
Halawa 138kv Expansion	–	–	–	–	–
Halawa 46 kV Bus OH to UG	–	–	–	–	–
Halawa Bkr#157–159 138kV P/I	–	–	–	–	–
Halawa Bkr#160–162 138kV P/I	–	–	–	–	–
Halawa Comm Equipment P/I	–	–	–	–	–
Halawa Control House P/I	–	–	–	–	–
Halawa Switch Replacements	–	–	–	–	–
Halawa Transfer #1 80MVA P/I	–	–	–	–	–
Halawa Transfer #2 80MVA P/I	–	–	–	–	–
Hal–Iwi 138 kV Line	–	–	–	–	–
Hal–Koo #1 138 kV Pole Repl	–	–	–	–	–

Project	2015	2016	2017	2018	2019
Hal–Koo #2 138 kV Line	–	–	–	–	–
Hal–Koo #3 138 kV Line	–	–	–	–	–
Hal–Mak 138 kV Line	–	–	–	–	–
Hal–Sch 138 kV Line	–	–	–	–	–
New Waiau 46kv Substation	–	–	67,514	4,038,621	16,331,839
North South Rd 46kV/12kV Ln	–	–	–	–	–
North South Rd Comm Links	–	–	–	–	–
North South Rd Substation	–	–	–	–	–
Waiau 138KV SS Sw & Stl Repl	32,409	147,135	2,590,538	2,892,272	1,937,918
Wai–Hal #1 138 kV Line	–	–	–	–	–
Wai–Hal #2 138 kV Line	–	–	–	–	–
Baseline	103,892,650	102,727,023	96,527,089	117,550,417	121,509,554
Safety, Security, and Environmental	23,215,183	11,837,693	18,429,378	20,427,213	10,238,531
Archer Sub 46kV GIS Replace	482,529	724,178	9,606,553	11,688,772	6,080,408
MATS Compliance	14,281,696	1,857,040	–	–	–
Baseline	8,450,958	9,256,475	8,822,825	8,738,441	4,158,122
Transformational	**167,116,018**	**498,596,891**	**249,158,042**	**134,982,423**	**116,057,501**
DG Enabling Investments	18,216,934	20,301,934	3,106,336	2,594,336	2,594,336
DGIP / Distribution Transformers	1,886,934	1,886,934	1,150,311	1,150,311	1,150,311
Baseline	15,840,000	15,840,000	1,444,025	1,444,025	1,444,025
Technology Demonstration	490,000	2,575,000	512,000		
Liquefied Natural Gas (LNG)	19,594,736	87,922,857	72,625,364	–	114,910
LNG	19,594,736	87,922,857	72,625,364	–	–
Pearl Harbor Substation	–	–	–	–	114,910
New and Renewable Energy	13,050,987	16,549,665	19,271,710	38,587,732	36,137,271
Flex Ops	5,649,956	10,843,411	13,285,436	6,966,467	732,341
New System 138kV Line				24,582,365	26,649,580
Baseline	7,401,031	5,706,254	5,986,274	7,038,900	8,755,350
Replace Dispatch Gen Capacity	16,117,138	83,616,273	67,924,068	256,223	–
Schofield Generating Station	16,117,138	83,616,273	67,924,068	256,223	–
Smart Grid and Demand Response	1,924,886	40,865,989	32,962,816	34,217,587	5,578,195
Smart Grid	–	40,865,989	32,962,816	34,217,587	5,578,195
Baseline	1,924,886	–	–	–	–
Security System Investments	52,048,129	249,029,171	53,267,746	59,326,545	71,632,788
EMS – Capital	–	–	–	–	–
EMS – Deferred	–	–	–	–	–
PSIP Storage Contingency	36,860,369	208,875,424	–	–	–
PSIP Storage Load Shift	–	–	–	–	–

Project	2015	2016	2017	2018	2019
TMP – DR Comm Projects	1,034,389	1,151,365	1,131,380	1,102,703	–
TMP – Freq Purch for Coll Pt	601,391	–	–	–	–
TMP Centra WaiauSwStn46/12kv	–	108,204	63,640	234,870	183,643
TMP Central – Airport Sub	–	191,584	112,590	415,746	325,056
TMP Central – Airport Sw Stn	–	221,467	130,096	474,843	375,421
TMP Central – Archer Sub	–	287,559	168,943	624,057	487,729
TMP Central – Halawa Baseyard	–	55,902	32,852	121,235	94,843
TMP Central – Honolulu PP	–	182,578	107,348	396,189	309,828
TMP Central – Makalapa Sub	–	226,357	128,742	490,857	236,015
TMP Central – School St. Sub	–	165,034	96,937	358,104	279,840
TMP Central– KaheSwStn (5–8)	–	106,643	62,615	231,372	180,774
TMP Central–Iwilei Sub 138/25	–	173,255	238,098	659,124	200,314
TMP Cntr ArptSub–Arpt SwF/O	–	389,874	–	–	–
TMP Core – American Savings	246,443	398,065	–	–	–
TMP Core – Grosvenor	57,276	–	–	–	–
TMP Core – Kahe PP	487,682	742,180	–	–	–
TMP Core – Waiau PP	417,890	636,066	–	–	–
TMP Core – Ward Ave	533,608	873,760	–	–	–
TMP Core Aina Koa–Pukele F/O	629,934	693,765	764,394	–	–
TMP Core Archer–Hon Club F/O	211,579	233,018	256,741	–	–
TMP Core ASB–CPP F/O	62,493	68,824	75,831	–	–
TMP Core HonClub – King F/O	179,363	197,539	217,649	–	–
TMP Core HPP–ASB F/O	69,234	76,249	84,012	–	–
TMP Core HPP–Iwiilei138 F/O	313,619	345,398	380,561	–	–
TMP Core Kahe to CEIP F/O	783,981	863,424	951,326	–	–
TMP Core Kamoku–Aina Koa F/O	740,063	815,054	898,032	–	–
TMP Core King – Ward F/O	69,234	76,249	84,012	–	–
TMP Core King to CPP F/O	69,234	76,249	84,012	–	–
TMP East – Halawa Sub	–	–	–	432,169	472,252
TMP East – Kamoku Sub	–	–	–	521,188	569,527
TMP East – Kewalo Sub	–	–	–	223,633	244,374
TMP East – Koolau Sub	–	–	–	290,802	317,773
TMP East – Mklp to Halawa F/O	–	–	–	1,800,997	1,986,620
TMP East – Piikoi Sub	–	–	–	218,192	283,119
TMP East – Pukule Sub	–	–	–	290,802	317,773
TMP East Archer–Piikoi F/O	–	–	–	285,135	310,566
TMP East KmkuUpper F/O	–	–	–	110,058	119,880
TMP East Piikoi to Ward F/O	–	–	–	285,135	310,566

Project	2015	2016	2017	2018	2019
TMP Edge – AES Power Plant	220,149	–	–	–	–
TMP Edge – Archer–HPP F/O	534,759	–	–	–	–
TMP Edge – Central Pac Plza	370,403	–	–	–	–
TMP Edge – Halawa Control Ctr	304,322	–	–	–	–
TMP Edge – HonClub Bldg	370,309	–	–	–	–
TMP Edge – Kalaeloa PP	417,351	–	–	–	–
TMP Edge – King St. Office	446,017	–	–	–	–
TMP Edge – Pauahi Tower	220,149	–	–	–	–
TMP Edge – Waterhouse	212,301	–	–	–	–
TMP West – AES Sub	–	–	–	328,062	358,490
TMP West – CEIP Sub	–	–	–	296,409	323,901
TMP West – Chevron	–	–	–	231,552	253,028
TMP West – CIP Power Plant	–	–	–	195,206	362,076
TMP West – HRRV	–	–	–	231,552	253,028
TMP West – Kalaeloa Sub	–	–	–	220,776	241,251
TMP West Kahe Sw Stn (1–4)	–	–	–	220,776	241,251
TMPCtrl ArptSwSpl–ArptSubF/O	–	651,281	–	–	–
Waiau–Makalapa Fiber Project	–	–	2,615,958	2,887,118	3,180,540
Baseline	5,584,587	30,146,804	44,581,978	45,147,883	58,813,310
Utility Scale Variable Renew Gen	46,163,207	311,001	–	–	–
K0–Kahe Utility Scale PV	46,163,207	311,001	–	–	–
Grand Totals	**480,525,190**	**833,138,381**	**570,363,144**	**506,968,830**	**477,240,888**

Table K-1. Capital Expenditures by Category and Project: 2015–2019

Capital Expenditures: 2020–2030 with Project Totals

Table K-2 lists the budgeted, annualized dollar amount for each project; with totals by project group and by category, for the years 2020–2030 with project totals.

Project	2020	2021–2025	2026–2030	Totals
Foundational	**386,426,502**	**1,351,966,232**	**1,173,728,925**	**4,614,447,219**
Asset Management	**101,614,836**	**183,684,838**	**201,170,403**	**1,231,315,232**
Ala Wai Canal 46kV U Relocation	–	–	–	20,975,487
Kahe Transfer #1 80MVA P/I	605,621	114,504	–	4,313,319
Koʻolau Transfer #1 80MVA P/I	1,332,691	–	–	3,172,671
Koʻolau Transfer #3 80MVA P/I	–	3,916,918	–	3,916,918
Pukele 80MVA Transfer #1	–	–	–	3,122,628
Pukele 80MVA Transfer #2	–	–	–	40,556
Wahiawa Transfer #1 80MVA P/I	89,587	3,849,008	–	3,958,455
Waiau Transfer A 80MVA P/I	–	–	–	3,401,649
Waiau Transfer B 80MVA P/I	–	–	–	3,655,732
Baseline	99,586,937	175,804,408	201,170,403	1,184,757,815
Customer Connections	**25,828,652**	**125,931,448**	**141,463,777**	**430,236,936**
Kalaeloa Substation	1,865,529	–	–	11,631,641
Ph1–Waipahu SS T&D	–	–	–	486,028
Ph1–Waipahu SS Transfer #3	–	–	–	1,326,108
Ph2–Pearl City SS T&D	–	–	–	56,999
Ph2–Pearl City SS Transfer #2	–	–	–	43,584
Ph3–Aiea for Stadium TS	–	–	–	48,455
Ph3–Keehi for Airport TS	–	–	–	4,582
Ph3–Lagoon for Lagoon TS	–	–	–	4,533
Ph4–Hon for Chinatown TS	–	–	–	221,731
Ph4–Kakaʻako for Civic TS	–	–	–	221,742
Ph4–Kewlo for Ala Moana TS	–	–	–	221,763
Ph4–Lagoon for Midd St TS	–	–	–	221,547
Baseline	23,963,123	125,931,448	141,463,777	415,748,223
Customer Projects	**2,404,664**	**916,164**	**1,016,824**	**14,689,767**
Baseline	2,404,664	916,164	1,016,824	14,689,767
Enterprise IT Framework	**10,808,064**	**72,139,227**	**91,171,890**	**276,854,997**
ADMS BR1 – OMS Core Functionality Capital	–	–	–	176,400
ADMS BR1 – OMS Core Functionality Deferred	–	–	–	4,943,195
Client Computing	2,718,790	15,741,639	20,023,884	50,717,493
ERP/EAM Capital	–	–	–	2,590,000

Project	2020	2021–2025	2026–2030	Totals
ERP/EAM Deferred	–	–	–	45,150,000
Future Software Implementations Capital	–	390,600	651,000	1,041,600
Future Software Implementations Deferred	–	10,555,848	17,593,080	28,148,928
IT Infrastructure	3,426,724	19,840,535	25,237,814	63,821,994
Baseline	4,662,550	25,610,606	27,666,113	80,265,388
Facilities	**98,932,724**	**272,819,831**	**50,353,638**	**461,132,301**
Ctrl Baseyard & Warehouse Facility	994,500	112,641,963	–	113,925,238
New SOCC – Construction	–	42,141,729	–	42,141,729
New SOCC – Land	–	8,000,000	–	8,000,000
Waiau ½	41,000	36,105,000	–	36,648,000
Office Building	90,000,000	–	–	90,000,000
Ward Office Renovation	–	10,000,000	–	10,000,000
New Warehouse	–	15,000,000	–	15,000,000
Baseline	7,897,224	48,931,140	50,353,638	145,417,334
Reliability	**142,105,863**	**677,003,859**	**671,405,536**	**2,074,720,569**
46kV Mobile Substation	–	–	–	2,469,465
DA–Smart Tech Installation	–	–	–	2,364,036
Dist Automation–Ena	–	–	–	2,291,821
Dist Automation–Kapahulu	–	–	–	2,299,357
Dist Automation–Kuhio	–	–	–	2,248,845
Dist Automation–Waikiki	–	–	–	2,286,809
Hal Bkr#176,4436,4492 P/I	45,233	23,553	93,176	161,962
Halawa 138kv Expansion	351,218	4,485,872	11,617,888	16,454,978
Halawa 46 kV Bus OH to UG	91,262	2,014,868	–	2,106,131
Halawa Bkr#157–159 138kV P/I	50,720	57,625	619,524	727,869
Halawa Bkr#160–162 138kV P/I	50,338	163,446	2,911,495	3,125,279
Halawa Comm Equipment P/I	187,083	3,177,291	99,769	3,464,143
Halawa Control House P/I	160,365	8,238,472	8,897,309	17,296,146
Halawa Switch Replacements	90,708	41,144	2,006,231	2,138,083
Halawa Transfer #1 80MVA P/I	114,798	51,059	3,010,761	3,176,618
Halawa Transfer #2 80MVA P/I	115,968	51,282	2,870,000	3,037,250
Hal–Iwi 138 kV Line	76,110	523,194	4,880,123	5,479,427
Hal–Koo #1 138 kV Pole Repl	88,862	1,018,629	3,219,330	4,326,821
Hal–Koo #2 138 kV Line	67,541	217,742	3,306,923	3,592,206
Hal–Koo #3 138 kV Line	66,248	40,336	547,411	653,995
Hal–Mak 138 kV Line	81,766	599,730	5,059,764	5,741,260
Hal–Sch 138 kV Line	79,508	452,859	5,066,546	5,598,913
New Waiau 46kv Substation	23,158,240	18,822,860	–	62,419,074

Project	2020	2021–2025	2026–2030	Totals
North South Rd 46kV/12kV Ln	–	4,597,597	150,390	4,747,987
North South Rd Comm Links	–	1,082,590	84,997	1,167,587
North South Rd Substation	–	7,800,314	357,864	8,158,178
Waiau 138KV SS Sw & Stl Repl	–	–	–	7,600,271
Wai–Hal #1 138 kV Line	83,698	85,449	739,143	908,290
Wai–Hal #2 138 kV Line	82,188	343,126	5,424,619	5,849,933
Baseline	117,064,009	623,114,820	610,442,274	1,892,827,836
Safety, Security, and Environmental	**4,731,698**	**19,470,865**	**17,146,856**	**125,497,417**
Archer Sub 46kV GIS Replace	–	–	–	28,582,439
MATS Compliance	–	–	–	16,138,736
Baseline	4,731,698	19,470,865	17,146,856	80,776,241
Transformational	**141,097,180**	**389,993,945**	**129,549,616**	**1,826,551,615**
DG Enabling Investments	**2,594,336**	**68,294,431**	**68,294,431**	**185,997,075**
DGIP / Distribution Transformers	1,150,311	4,050,031	4,050,031	16,475,175
Baseline	1,444,025	64,244,400	64,244,400	165,944,900
Technology Demonstration		–	–	3,577,000
Liquefied Natural Gas (LNG)	**6,527,129**	**10,985**	**–**	**186,795,981**
LNG	–	–	–	180,142,958
Pearl Harbor Substation	6,527,129	10,985	–	6,653,024
New and Renewable Energy	**36,789,498**	**106,218,131**	**43,377,682**	**309,982,676**
Flex Ops	–	–	–	37,477,611
New System 138kV Line	28,890,521	65,273,327	–	145,395,793
Baseline	7,898,977	40,944,804	43,377,682	127,109,272
Replace Dispatch Gen Capacity	**–**	**–**	**–**	**167,913,702**
Schofield Generating Station	–	–	–	167,913,702
Smart Grid and Demand Response	**5,090,373**	**28,752,932**	**10,167,351**	**159,560,130**
Smart Grid	5,090,373	28,752,932	10,167,351	157,635,244
Baseline	–	–	–	1,924,886
Security System Investments	**90,095,844**	**186,717,466**	**7,710,153**	**769,827,843**
EMS – Capital	802,700	1,304,387	802,700	2,909,786
EMS – Deferred	4,000,000	11,200,000	–	15,200,000
PSIP Storage Contingency	–	–	–	245,735,793
PSIP Storage Load Shift	18,964,743	107,466,877	–	126,431,620
TMP – DR Comm Projects	–	–	–	4,419,836
TMP – Freq Purch for Coll Pt	–	–	–	601,391
TMP Central WaiauSwStn46/12kv	–	–	–	590,357
TMP Central – Airport Sub	–	–	–	1,044,977
TMP Central – Airport Sw Stn	–	–	–	1,201,826

Project	2020	2021–2025	2026–2030	Totals
TMP Central – Archer Sub	–	–	–	1,568,288
TMP Central – Halawa Baseyard	–	–	–	304,832
TMP Central – Honolulu PP	–	–	–	995,943
TMP Central – Makalapa Sub	–	–	–	1,081,971
TMP Central – School St. Sub	–	–	–	899,914
TMP Central– KaheSwStn (5–8)	–	–	–	581,405
TMP Central–Iwilei Sub 138/25	–	–	–	1,270,791
TMP Cntr ArptSub–Arpt SwF/O	–	–	–	389,874
TMP Core – American Savings	–	–	–	644,508
TMP Core – Grosvenor	–	–	–	57,276
TMP Core – Kahe PP	–	–	–	1,229,861
TMP Core – Waiau PP	–	–	–	1,053,956
TMP Core – Ward Ave	–	–	–	1,407,368
TMP Core Aina Koa–Pukele F/O	–	–	–	2,088,093
TMP Core Archer–Hon Club F/O	–	–	–	701,338
TMP Core ASB–CPP F/O	–	–	–	207,147
TMP Core HonClub – King F/O	–	–	–	594,551
TMP Core HPP–ASB F/O	–	–	–	229,495
TMP Core HPP–Iwiilei138 F/O	–	–	–	1,039,578
TMP Core Kahe to CEIP F/O	–	–	–	2,598,731
TMP Core Kamoku–Aina Koa F/O	–	–	–	2,453,149
TMP Core King – Ward F/O	–	–	–	229,495
TMP Core King to CPP F/O	–	–	–	229,495
TMP East – Halawa Sub	475,800	–	–	1,380,221
TMP East – Kamoku Sub	573,803	–	–	1,664,518
TMP East – Kewalo Sub	246,209	–	–	714,216
TMP East – Ko‘olau Sub	320,159	–	–	928,734
TMP East – Mklp to Halawa F/O	–	–	–	3,787,618
TMP East – Pi‘ikoi Sub	97,748	–	–	599,059
TMP East – Pukule Sub	320,159	–	–	928,734
TMP East Archer–Piikoi F/O	–	–	–	595,701
TMP East KmkuUpper F/O	–	–	–	229,939
TMP East Pi‘ikoi to Ward F/O	–	–	–	595,701
TMP Edge – AES Power Plant	–	–	–	220,149
TMP Edge – Archer–HPP F/O	–	–	–	534,759
TMP Edge – Central Pac Plza	–	–	–	370,403
TMP Edge – Halawa Control Ctr	–	–	–	304,322
TMP Edge – HonClub Bldg	–	–	–	370,309

Project	2020	2021–2025	2026–2030	Totals
TMP Edge – Kalaeloa PP	–	–	–	417,351
TMP Edge – King St. Office	–	–	–	446,017
TMP Edge – Pauahi Tower	–	–	–	220,149
TMP Edge – Waterhouse	–	–	–	212,301
TMP West – AES Sub	361,183	–	–	1,047,736
TMP West – CEIP Sub	326,333	–	–	946,643
TMP West – Chevron	254,929	–	–	739,508
TMP West – CIP Power Plant	295,836	–	–	853,118
TMP West – HRRV	254,929	–	–	739,508
TMP West – Kalaeloa Sub	243,063	–	–	705,089
TMP West Kahe Sw Stn (1–4)	243,063	–	–	705,089
TMP Ctrl ArptSwSpl–ArptSubF/O	–	–	–	651,281
Waiau–Makalapa Fiber Project	–	–	–	8,683,616
Baseline	62,315,186	66,746,202	6,907,454	320,243,405
Utility Scale Variable Renew Gen	**–**	**–**	**–**	**46,474,208**
K0–Kahe Utility Scale PV	–	–	–	46,474,208
Grand Totals	**527,523,682**	**1,741,960,177**	**1,303,278,541**	**6,440,998,833**

Table K-2. Capital Expenditures: 2020–2030 with Project Totals

L. Preferred Plan Development

The Preferred Plan was developed within a, highly analytical, and innovative process. These elements were critical in developing the Preferred Plan. Collaboration between power system planners, consultants, domain experts, 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. While analytics are the centerpiece of the effort, it was critical to incorporate our strategic vision in the search for innovative ways to implement and leverage energy storage and renewable variable energy sources.

The planning process leveraged the expertise of three modeling teams, using three different models, to address simulation requirements. One purpose of utilizing three teams was to gain confidence in the final recommendation by seeing if different models and approaches provided similar, reinforcing results. This outcome has been realized. The second purpose has turned out to be more critical to planning efforts. Collaboration between the three teams to develop and share theories or options for improvement of the power supply plans, based on incremental results, proved invaluable.

Collectively, the teams worked together to move from concept, through refinement, to definition of the preferred plan.

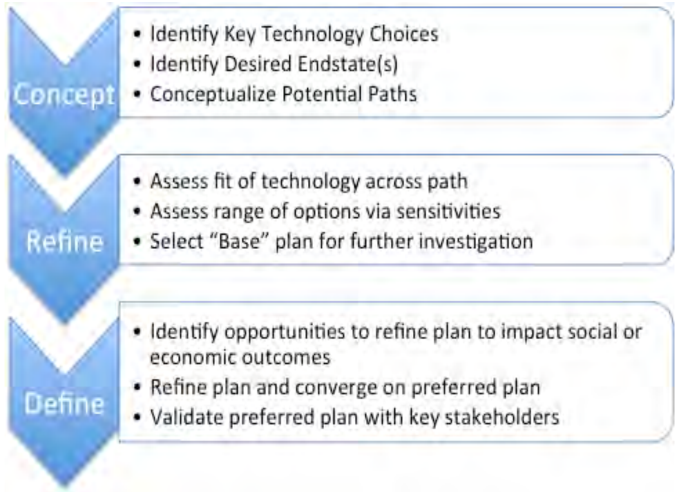


Figure L-1. Process for Developing the Preferred Plan

The analysis focused on transforming today's system into an electrical system that safely and securely integrates various sources of renewable energy by 2030. The analysis was carried out in three major steps:

1. **Develop a Base Plan.** In the first phase, a Base Plan was constructed to meet the primary goal of renewing the system by replacing the existing units with more flexible and responsive units that also met the capacity planning criteria.
2. **Perform Sensitivity Analyses.** Sensitivity analyses were then performed to the Base Plan to test various changes to the plan.
3. **Use Sensitivity Results to Develop the Preferred Plan.** The results of the sensitivity analyses were reviewed and used to develop the Preferred Plan.

Actions taken now and projects developed in next five years will have a strong effect on possibilities in the future. Therefore, great care was taken to develop a Preferred Plan that is flexible enough to accommodate emerging green technology options that become commercially ready in the future. The Preferred Plan positions Hawaiian Electric to address both current and emerging technology options.

METHODOLOGY FOR DEVELOPING THE PREFERRED PLAN

The PSIP planning teams constructed and evaluated a number of strategy canvases to feed a more granular and complex process that vetted technology options. Development of the Preferred Plan was driven by the following concepts:

- Focus on maximizing renewable content – of all types as feasible given specifics of each island while evaluating the economic impacts.

- Develop a grid that can manage large volumes of variable generation; define a technology strategy that allows this capability to evolve over time.
- Utilize conventional, dispatchable thermal assets to provide firm generation and regulation; utilize LNG to improve fuel supply economics and reduce CO2 emissions.
- Maintain safety and reliability by assuring grid stability needs are met and can keep pace with increasing variability of major generation sources – making energy storage a centerpiece of the strategy.

The modeling teams focused on constructing tactical plans to identify specific steps required to transition from current state to future state. This was a complex and iterative process. Plans were broken down into a series of annual capital project/retirement plans; each plan was verified against system security reliability requirements. Operations of the system within each annual plan was carried out by detailed production simulation models that commit and dispatch assets, manage regulation, and utilize energy storage systems (ESS) or other asset to address variability of solar or wind generation potential, and consider demand response options. As discussed further in Appendix C, these models apply detailed hourly and sub-hourly dispatch models to clarify how to best utilize and value generation or regulation options. While the three different production simulation models employ somewhat different algorithms to simulate power system operations, all of the models are based on electric utility planning and operating practices accepted throughout the world.

The planning process leveraged three models and three modeling teams to address simulation requirements. Collectively, the teams worked together to move the plan from concept, through refinement, to definition of the preferred plan. Specific milestones within the planning process included:

- Test and validate potential 2030 scenarios and technology options to validate the long-term vision captured in the central strategy
- Identification of key success factors or critical technology investments underpinning the 2030 strategy (i.e., diversification of renewables, early adoption of advanced battery for contingency and regulation, LNG supply for thermal assets).
- Validation of the supply mix and roles between variable renewables, dispatchable renewables, and thermal assets to address spin/regulation; this mix defines the degree to which variable assets can be leveraged.
- Optimization of the thermal portfolio based on requirements during each of year of the study period; identify blend of fast start/fast response and more efficient combined cycle technologies against demand and retirement schedules and identify intrinsic value of shifting retirement dates.

- Identify and test alternate technology mixes, timing, and other pros & cons via sensitivity analysis.
- Expand sensitivity analysis into areas of key interest. This varied by island. For O'ahu - degree of solar and additional wind to increase RPS; for Maui - cost containment/operational improvements enabled by select energy storage and renewable projects, and for the Big Island - economic viability of further expanding wind and/or geothermal footprints.
- Identify preferred plan based sensitivities; verification of plan outcomes by all three models and modeling teams.

System reliability requirements for regulating and contingency reserves were met through a variety of resources including demand response, energy storage, and thermal generation. As increasing amounts of renewable variable generation were added to the system, the system reliability requirements changed annually to reflect the new generation mix.

Sub-hourly models were deployed during the course of the analysis to verify understanding of ESS, demand response, and thermal asset use within short (5-min) increments. Results were compared to hourly models to identify whether substantial changes to operations would be expected; sub-hourly models demonstrated need for and value of balancing variable resources with sufficient ESS and regulating reserve from thermal units.

In constructing and validating the Preferred Plan, the last step in the process involved broader participation of domain experts to fully vet the plan and identify any remaining issues to be addressed. This allowed collective model teams to better assure that models were consistent with operational realities and that plan objectives were met.

Base Plan

The Base Plan seeks to maximize the amount of variable renewable generation that can be accepted on the existing system and creates the flexibility to accommodate additional renewable energy in the future.

In the near term, various system changes are incorporated to improve the flexibility of the existing generation. This operational flexibility is achieved through modifications to existing utility and Independent Power Producer (IPP) generation, specifically by lowering unit minimums and enabling a change in operational modes from base load to cycling. The base plan also included assumptions regarding which units would be converted to LNG fuel. These changes were incorporated into the simulation models.

Utility Generation

- Kahe Units 1-5 and Waiau Units 7 & 8 are enabled to operate at lower unit minimums in 2016
- Kahe Units 1 - 4 will be allowed to cycle but will incur an O&M cost for each start by 2016
- All existing utility generation will fuel switch to LNG in 2017 (except CIP CT-1)

Kalaeloa Energy Partners (KPLP)

- KPLP will fuel switch to LNG in 2017
- KPLP will change operation from dual train combined cycle to a single train combined cycle and run one CT in simple cycle mode

AES

- AES will continue beyond the end of its current contract in 2022 but at a reduced capacity of 90 MW

Future Utility/IPP Generation

- Schofield is in service in 2018
- Na Pua Makani is in service in 2016
- Mililani South Solar Park is in service in 2017
- Waiver projects in service in 2017

To transition from our current state to the 2030 vision, the Base Plan deactivates and retires existing generation based on a retirement schedule starting in 2022. This year was chosen based on the timeframe to acquire new firm generation through the a competitive procurement process which is estimated as approximately 6–7 years for new generation to be installed. New flexible combustion turbines are added to the system to satisfy the capacity planning criteria based on the deactivation schedule. Units are retired (decommissioned) two years after deactivation. Note, the deactivation schedule was tested through modeling of different scenarios so the schedule in the Preferred Plan was not assumed, but validated as part of the overall plan.

New flexible combustion turbines are installed that can cycle off daily and ramp quickly. These units provide the ramping capabilities and regulating reserves required to support increasing PV and wind resources on the system in addition to the ancillary services provided by demand response, energy storage, and variable generation.

Utility deactivation of existing generation:

- Waiau 3 & 4 in 2017
- Waiau 5 & 6 in 2028
- Waiau 7 & 8 in 2030

- Kahe 1 & 2 in 2023
- Kahe 3 & 4 in 2024
- Kahe 5 & 6 in 2022

New generation:

- 285 MW in 2022
- 190 MW in 2023
- 95 MW in 2024
- 95 MW in 2030

Sensitivity Analyses

Sensitivity analyses will be performed on the Base Plan to demonstrate the effect of various changes to the system. The sensitivity analyses evaluated the following on Oʻahu:

AES

- AES at 180 MW using coal
- AES at 180 MW using coal with 100 MW load shifting battery energy storage
- AES at 90 MW using biomass
- AES at 180 MW using 50% biomass and 50% coal

CIP CT-1

- Convert to LNG
- Continue to use biodiesel with contract minimum
- Continue to use biodiesel with economic dispatch and no fuel contract minimum

Waiau 9 & 10 Fuel Use

Additional Renewable Energy Resources

- Include additional 50 MW of wind on Oʻahu
- Include additional 250 MW of utility-scale PV on Oʻahu
- Include additional 150 MW of utility-scale PV on Oʻahu
- Include additional 50 MW wind and 150 MW of utility-scale PV on Oʻahu

Pumped Storage Hydro

- Without increasing PV levels above the Base Plan
- With increasing PV levels above the Base Plan

Future Firm Generation Mix

Sensitivity analyses were performed to test how a particular condition would affect the Base Plan and whether it should be considered for incorporation into the Preferred Plan. The analyses were conducted by the three independent modeling teams (Hawaiian Electric, Black & Veatch, and PA Consulting) and the results are described in this appendix.

Existing Generating Units

The Base Plan included some assumptions that warranted sensitivity analyses to test their robustness. The sensitivity analyses to test the future of existing generating units include:

- AES PPA
- CIP CT-1
- Waiau 9 & 10

AES

The existing PPA with AES expires in 2022. In the Base Plan, we assumed a new power purchase agreement (PPA) would become effective after 2022, but the output from AES would be reduced to a maximum of 90 MW in order to minimize baseload generation in an effort to accommodate more variable renewable generation. Sensitivity analyses performed on this AES assumption varied the capacity and fuel source for this generating unit.

AES at 180 MW using coal

This sensitivity analysis looked at the effect of continuing AES at their current 180 MW rating beyond the contract expiration in 2022. Energy and capacity payments to AES continued to use the current contract formula. The analysis showed that AES continuing at 180 MW using coal decreased the overall system cost compared to the Base Plan. However, AES did not contribute to RPS under this assumption so this was not included in the Preferred Plan.

AES at 180 MW using coal with 100 MW load shifting battery energy storage

This sensitivity analysis assumed that the increased curtailment that occurs when AES continues at 180 MW (instead of 90 MW) is mitigated by a load shifting battery energy storage. The energy storage accepts curtailed renewable energy from the day and discharges during the evening peak. In addition to reducing daytime curtailment, the load shifting battery provides firm capacity during the evening peak and replaces the need for a future 100 MW combustion turbine. The analysis showed that continuing AES at 180 MW using coal and including a 100 MW load shifting energy storage resulted in some cost savings compared to the Base Plan. However, this did not increase the RPS so this AES configuration was not favorable compared to other options and was not included in the Preferred Plan.

AES at 90 MW using biomass

This sensitivity analysis assumed that AES continues at 90 MW using biomass to evaluate the benefit of using a renewable fuel on a baseloaded unit. The analysis showed that continuing AES at 90 MW on biomass increased the RPS. However, the overall system costs compared to the Base Plan increased significantly so this assumption was not included in the Preferred Plan.

AES at 180 MW using 50% biomass and 50% coal

Considering the results of the sensitivity analyses with AES at 180 MW and the benefit of using a renewable fuel source, this sensitivity analysis combined the biomass with coal to create a lower cost, moderately renewable fuel. The analysis showed that continuing AES at 180 MW using a 50% biomass and 50% coal fuel blend increased the overall system costs compared to the Base Plan but increased the RPS significantly so this assumption was included in the Preferred Plan.

CIP CT-1

In the Base Plan, we assumed that CIP CT-1 would use ULSD from 2018 after the current biodiesel fuel contract ends. Sensitivities around the CIP CT-1 assumption varied the fuel source and contract minimum for this generating unit.

Convert to LNG

This sensitivity analysis assumed that CIP CT-1 converts to LNG. The analysis showed that converting CIP CT-1 to LNG increased the overall system costs compared to the Base Plan and did not increase the RPS. This assumption was not included in the Preferred Plan.

Continue to use biodiesel with contract minimum

This sensitivity analysis assumed that CIP CT-1 continues on biodiesel with a contract minimum to burn 3 million gallons per year. The analysis showed that continuing CIP CT-1 on biodiesel with a fuel minimum increased the overall system costs compared to the Base Plan and did not increase the RPS significantly so this assumption was not included in the Preferred Plan.

Continue to use biodiesel with economic dispatch and no fuel contract minimum

This sensitivity analysis assumed that CIP CT-1 continues on biodiesel but is allowed to economically dispatch to meet system load. The analysis showed that economically dispatching CIP CT-1 on biodiesel increased the overall system costs compared to the

Base Plan and did not increase the RPS significantly so this assumption was not included in the Preferred Plan.

Waiau 9 & 10

In the Base Plan, we assumed that Waiau 9 & 10 would be converted to use LNG. This sensitivity analysis looked at not converting to LNG and instead, using ULSD in the units. The analysis showed that using ULSD in Waiau 9 & 10 decreased the overall system costs compared to the Base Plan and was included in the Preferred Plan.

Additional renewable energy resources

The Base Plan includes known renewable energy projects already in the pipeline such as the Schofield Generating Station, Kahe solar, waiver PV projects, Mililani South Solar Park, and Na Pua Makani wind. Sensitivity analyses looked at the effect of adding additional renewable energy resources such as:

- Wind
- Utility-scale PV
- Wind and Utility-scale PV

Wind

This sensitivity analysis added 50 MW of wind on O'ahu. An additional 50 MW of wind increased the overall system costs compared to the Base Plan and increased the RPS. This assumption was further evaluated in other sensitivities for inclusion in the Preferred Plan.

Utility-Scale PV

With the transformation to reduce baseload generation in the Base Plan, sensitivity analyses were performed to test the effect of additional utility-scale PV on a more flexible system.

Additional 250 MW

This sensitivity analysis added 250 MW of utility-scale PV on O'ahu. An additional 250 MW of utility-scale PV increased the overall system costs compared to the Base Plan and increased the RPS. This assumption was further evaluated in other sensitivities for inclusion in the Preferred Plan.

Additional 150 MW

This sensitivity analysis added 150 MW of utility-scale PV on O'ahu. An additional 150 MW of utility-scale PV increased the overall system costs compared to the Base Plan and increased the RPS. This assumption was further evaluated in other sensitivities for inclusion in the Preferred Plan.

Wind and Utility-Scale PV

The sensitivity analyses showed that incremental additions of wind and utility-scale PV could be integrated into the system. This analysis combined the addition of 50 MW of wind and 150 MW of utility-scale PV for more resource diversity. The analysis showed that adding 50 MW of wind and 150 MW of utility-scale PV increased overall system costs compared to the Base Plan but increased the RPS. As a result this analysis, a mix of additional renewable resources was included in the Preferred Plan.

Pumped Storage Hydro

The pumped storage hydro has operating characteristics similar to a load shifting battery energy storage. This resource was assumed to provide firm capacity that can defer future generation and reduce curtailment by accepting curtailed renewable energy during the day to be discharged at the evening peak. Sensitivity analyses were conducted to examine the effect of adding a pumped storage hydro resource on the system.

- 100 MW Pumped Storage Hydro
- 100 MW Pumped Storage Hydro and 100 MW Utility-scale PV

100 MW Pumped Storage Hydro

This sensitivity analysis added a 100 MW pumped storage hydro. The pumped storage hydro deferred the installation of a combustion turbine in the year it was placed in service. The 100 MW pumped storage hydro increased the overall system costs compared to the Base Plan and did not increase the RPS so this assumption was not included in the Preferred Plan.

100 MW Pumped Storage Hydro and 100 MW Utility-scale PV

This sensitivity analysis coupled a 100 MW utility-scale PV with a 100 MW pumped storage hydro. The energy provided by the 100 MW utility-scale PV was used to charge the pumped storage hydro during the day and was discharged at night during the evening peak. The pumped storage hydro again deferred the need for one combustion turbine. The 100 MW pumped storage hydro and 100 MW utility-scale PV increased the overall system costs compared to the Base Plan and increased RPS. This assumption was not included in the Preferred Plan.

Future Firm Generation Mix

The Base Plan assumed that future capacity needed to meet the capacity planning criteria would be provided by 100 MW combustion turbines. This sensitivity analysis assumed a mix of combustion turbines, combined cycle combustion turbines, and internal combustion engines that provided a more diverse set of operating characteristics for the future generation fleet. This future firm generation mix decreased the overall system costs compared to the Base Plan and was included in the Preferred Plan.

PREFERRED PLAN

The results of the sensitivity analyses that show positive impacts to the Base Plan were considered for incorporation into revising the Base Plan. Revisions to the Base Plan include a combination of results from the sensitivity analyses to produce the Preferred Plan which must be tested to assure system security reliability.

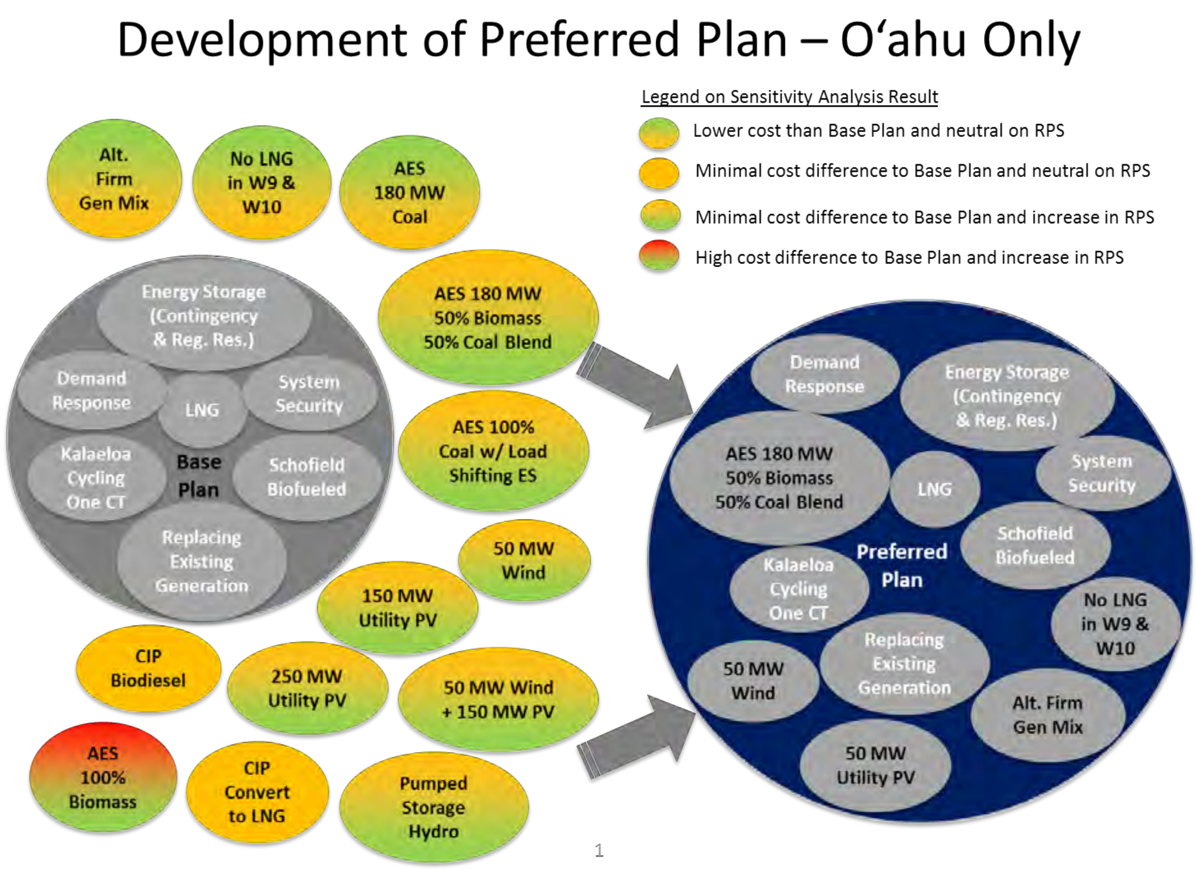


Figure L-2. Illustration of the Process for Developing the Hawaiian Electric Preferred Plan

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M: Planning Standards

This appendix contains the details of the planning standards TPL-001 and BAL-052.

TPL-001-0: TRANSMISSION PLANNING PERFORMANCE REQUIREMENTS

The starting document for HI-TPL-001-0 was NERC standard TPL-001-2 dated August 4, 2011. The standard includes the merging of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single comprehensive, coordinated standard and retirement of TPL-005-0 and TPL-006-0.

The only added complexity was that the differently sized power systems in Hawaiʻi would need different levels of system reliability. The Hawaiʻi standard has three groups to address the different sizes of the various Balancing Areas.

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Working Group Glossary of Terms, Version 1 – 20120304 are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Balancing Authority (BA): The responsible entity that integrates resource plans ahead of time, maintains load-generation balance within a Balancing Authority Area, and governs the real time operation and control of the Balancing Area. (Source: Modified from Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Balancing Authority Area: The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012)

Base Year: The 2011 BA's transmission and generation system shall be used as the base year to establish performance standards utilized with this standard. (Source: Proposed RSWG proposed definition.)

Cascading: The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Corrective Action Plan: A list of actions and an associated timetable for implementation to remedy a specific problem. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Equipment Rating: The maximum and minimum voltage, current, frequency, real and reactive power flows on individual equipment under steady state, short-circuit and transient conditions, as permitted or assigned by the equipment owner. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Facility: A set of electrical equipment that operates as a single Bulk Electric System Element (for example, a line, a generator, a shunt compensator, transformer, etc.). (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Near-Term Transmission Planning Horizon: The transmission planning period that covers Year One through five. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive load, or (3) load that is disconnected from the system by end-user equipment. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Off-Peak: Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of lower electrical demand. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Operating Procedure: A document that identifies specific steps or tasks that should be taken by one or more specific operating positions to achieve specific operating goal(s). The steps in an Operating Procedure should be followed in the order in which they are presented, and should be performed by the position(s) identified. A document that lists the specific steps for a system operator to take in removing a specific transmission line from service is an example of an Operating Procedure. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Planning Assessment: Documented evaluation of future Transmission system performance and Corrective Action Plans to remedy identified deficiencies. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Protection System: Protection system are:

- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

(Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Protection Reserves: The resources under the control of the Under Frequency Load Shedding System designed to protect the system against single or multiple contingency events. (Source: RSWG proposed definition.)

Special Protection System (SPS) or Remedial Action Scheme: An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and MVAr), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Stability: The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

System: A combination of generation, transmission, and distribution components. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Transmission: An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers. (Source: Modified Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Year One: Year One is the first year of planning studies for future planning and evaluation requirements. (Source: Modified Glossary of Terms Used in NERC Reliability Standards February 8, 2012, Reliability First Regional Definitions.)

Introduction

Purpose: Establish Transmission system planning performance requirements within the planning horizon to develop a system that will operate reliably over a broad spectrum of conditions and following a wide range of probable Contingencies.

Applicability: Balancing Authorities (BA)

Facilities: The Facilities are divided into three groups A, B, and C. All groups are divided based on the annual system peak demand.

- Group A: Annual system peak is greater than or equal to 500 MW.
- Group B: Annual system peak is greater than or equal to 50 MW and less than 500 MW.
- Group C: Annual system peak is less than 50 MW.

Effective Date: To be determined

B. Requirements

R1. The BA must maintain system models for performing the studies needed to complete its Planning Assessment. The models must use data consistent with that provided in accordance with the HI-MOD-010 Development and Reporting of Steady State System Models and Simulations and HI-MOD-012 Development and Reporting of Dynamic System Models and Simulations standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and must represent projected system conditions. This establishes Category P0 as the normal system condition in Table 1.

R1.1. System models must represent:

R1.1.1. Actual steady-state characteristics of system resources and loads as defined in HI-MOD-010 Development and Reporting of Steady State System Models and Simulations.

R1.1.2. Actual dynamic characteristics of system resources and loads as defined in HI-MOD-012 Development and Reporting of Dynamic System Models and Simulations.

R1.1.3. Planned Facilities and changes to existing Facilities

R1.2. The Generation resources must maintain or better the following characteristics unless the change can be verified by study that the results will provide acceptable reliability. The characteristics of the system that meet the acceptable reliability criteria will be used as the new benchmark for future planning until the reliability criteria is changed.

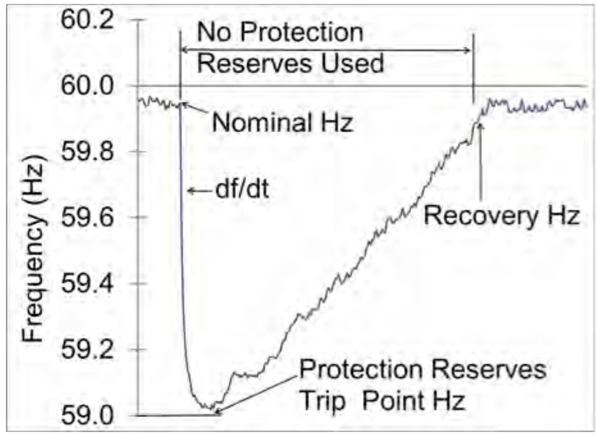
R1.2.1. Each Balance Authority system will be planned to meet the requirements Disturbance Recovery performance in HI-BAL-002 Disturbance Control Performance.

R1.2.2. The loss of the largest single contingency may result in a loss of load within the acceptable reliability criteria defined in BAL-002 Disturbance Control Performance.

R1.2.3. Each resource will have frequency ride-through designed such that all generation, reserves, regulation and voltage control resources will withstand single and excess contingency events defined in HI-BAL-002 Disturbance Control Performance. The ride-through capability will meet the criteria designed to be protected under HI-PRC-006 Underfrequency Load Shedding, without the loss of, or damage to any resource.

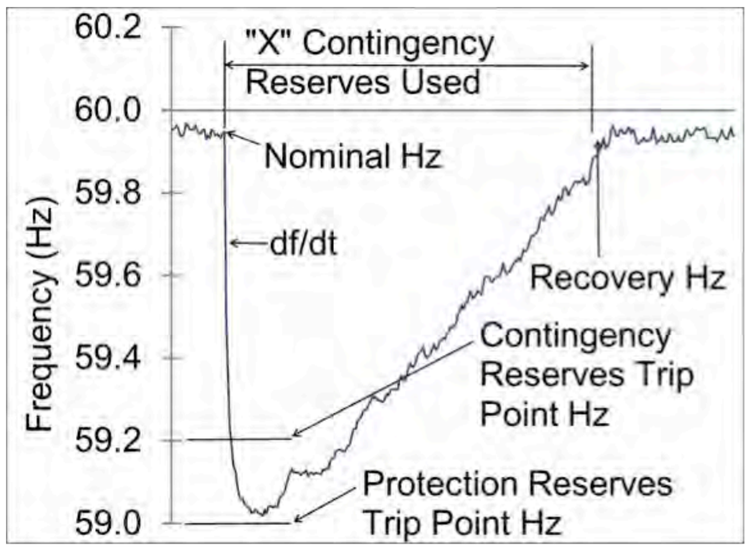
R1.2.4. The system will be planned such that the resultant impacts of inertia, unit response or reserve response will meet the system frequency response characteristics following the loss of the largest single contingency as defined below.

Frequency Response: For all BA systems the loss of the largest unit(s) or any single contingency should not result in activation of the protection reserves. In addition, the rate of change of frequency df/dt is not to increase over historical levels, without prior review of impacts on system protection operation and critical resources. A sample system performance characteristic is shown in the graph below:



System Using No Protection Reserves

An example characteristic graph of a system that utilizing the protection reserves is indicated below:



System Using Protection Reserves

R.1.2.5. The system will be planned such that all generation, reserves, regulation and voltage control resources will withstand the most severe voltage ride-thru requirement for a single contingency event, including both transmission and distribution events and distribution and transmission fault reclose cycles, through the duration of their reclosing cycle, without the loss of or damage to any resource.

R1.2.6. The system will be designed such that all generation, reserves, regulation and voltage control resources will withstand excess contingency events defined in HI-BAL-002 Disturbance Control Performance for voltage ride-thru requirement for an excess contingency event and designed to be protected under HI-PRC-006

Underfrequency Load Shedding, without the loss of or damage to any resource.

R1.2.7. The system will be planned to be transiently and dynamically stable following any single contingency event or any excess contingency event designed to be protected under HI-PRC-006 Underfrequency Load Shedding. Stability will be defined that the system will survive the first swing stability and the second swing and each subsequent swing will be lesser in magnitude than its predecessor (damped response). All swings will be effectively eliminated within 20 seconds of the initiating event.

R1.2.8. The system shall be designed to supply the required ancillary services necessary to provide voltage and frequency response to meet the reliability requirements of each BA's service tariff and R1.2.2.

R2. The BA must prepare an annual Planning Assessment of its system. This Planning Assessment must use current or qualified past studies (as indicated in R2.6), document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and Stability analyses.

R2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis must be assessed annually and be supported by current annual studies or qualified past studies as indicated in R2.6. Qualifying studies need to include the following conditions:

R2.1.1. System peak load for either year one or year two, and for year five.

R2.1.2. System minimum with maximum and minimum variable renewables (night-time load) load for one of the five years.

R2.1.3. System minimum day load, maximum variable renewable for one of the five years.

R2.1.4. System day-peak load with maximum variable renewable and minimum variable renewable for one of the five years.

R2.1.5. System peak load, no variable renewable for one of the five years.

R2.1.6. For each of the studies described in R2.1.1 through R2.1.5, sensitivity case(s) must be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the system within a range of credible conditions that demonstrate a measurable change in system response:

- Real and reactive forecasted load.
- Expected transfers.
- Expected in-service dates of new or modified Transmission Facilities.
- Planned or unplanned outages of critical resources for ancillary services
- Typical generation scenarios including outage of the typically operated generation sources
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable loads and Demand Side Management.

R2.1.7. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on system performance must be studied. The studies must be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the system is expected to experience during the possible unavailability of the long lead time equipment.

R2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis must be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in R2.6:

R2.2.1. A current study assessing expected system peak load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

R2.3. The short circuit analysis portion of the Planning Assessment must be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in R2.6. The analysis must be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the system short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

R2.4. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis must be assessed annually and be supported by current or past studies as qualified in R2.6. The following studies are required:

R2.4.1. System peak load for one of the five years. System peak load levels must include a load model which represents the expected dynamic behavior of loads that could impact the study area, considering the behavior of induction motor loads or other load characteristics, including the model of distributed generation, Demand Response and other programs that impact system load characteristics. An aggregate system load model which represents the overall dynamic behavior of the load is acceptable.

R2.4.2. System minimum load for one of the five years.

R2.4.3. System minimum with maximum and minimum variable renewables (night-time load) load for one of the five years.

R2.4.4. System minimum day load, maximum variable renewable for one of the five years.

R2.4.5. System day-peak load, maximum and minimum variable renewable for one of the five years.

R2.4.6. System peak load, no variable renewable for one of the five years.

R2.4.7. For each of the studies described in R2.4.1 through R2.4.6, sensitivity case(s) must be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the system within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, load forecast, or dynamic load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability
- Maintenance periods of generation resources and alternative resources providing ancillary services.
- Generation additions, retirements, or other dispatch scenarios.

R2.5. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis must be assessed to address the impact of proposed material generation additions or changes in that time frame and be supported by current or past studies as qualified in R2.6 and must include documentation to support the technical rationale for determining material changes.

R2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

R2.6.1. For steady state, short circuit, or Stability analysis: the study must be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

R2.6.2. For steady state, short circuit, or Stability analysis: no material changes have occurred to the system represented in the study. Documentation to support the technical rationale for determining material changes must be included.

R2.7. For planning events shown in Table 1, when the analysis indicates an inability of the system to meet the performance requirements in Table 1, the Planning Assessment must include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned system must continue to meet the performance requirements in Table 1. The Corrective Action Plan(s) must:

R2.7.1. List system deficiencies and the associated actions needed to achieve required system performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment
- Installation, modification, or removal of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations
- Installation or modification of manual and automatic generation runback or tripping as a response to a single or multiple Contingency to mitigate steady state performance violations

- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan
- Use of rate applications, DSM, alternative resources and technologies, or other initiatives

R2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

R2.7.3. If situations arise that are beyond the control of the BA that prevent the implementation of a Corrective Action Plan in the required time frame, then the BA is permitted to utilize Non-Consequential Load Loss to correct the situation that would normally not be permitted in Table 1, provided that the BA documents that they are taking actions to resolve the situation. The BA must document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load.

R2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified system Facilities and Operating Procedures.

R2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in R2.3 exceeds their Equipment Rating, the Planning Assessment must include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan must:

R2.8.1. List system deficiencies and the associated actions needed to achieve required system performance.

R2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

R3. For the steady state portion of the Planning Assessment, the BA must perform studies for the Near-Term and Long-Term Transmission Planning Horizons in R2.1, and R2.2. The studies must be based on computer simulation models using data provided in R1.

R3.1. Studies must be performed for planning events to determine whether the system meets the performance requirements in Table 1 based on the Contingency list created in R3.4.

R3.2. Studies must be performed to assess the impact of the extreme events which are identified by the list created in R3.5.

R3.3. Contingency analyses for R3.1 & R3.2 must:

R3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses must include the impact of subsequent:

- Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.
- Tripping of Transmission elements where relay loadability limits are exceeded.
- Tripping of generation and other resources (including distributed resources) where ride-thru capabilities are exceeded

R3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

R3.4. Those planning events in Table 1, that are expected to produce more severe system impacts must be identified and a list of those Contingencies to be evaluated for system performance in R3.1 created. The rationale for those Contingencies selected for evaluation must be available as supporting information.

R3.5. Those extreme events in Table 1 that are expected to produce more severe system impacts must be identified and a list created of those events to be evaluated in R3.2. The rationale for those Contingencies selected for evaluation must be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) must be conducted.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, the BA must perform the Contingency analyses listed in

Table 1. The studies must be based on computer simulation models using data provided in Requirement R1.

R4.1. Studies must be performed for planning events to determine whether the system meets the performance requirements in Table 1 based on the Contingency list created in R4.4.

R4.1.1. For planning event P1: No generating unit must pull out of synchronism. A generator being disconnected from the system by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.

R4.1.2. For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings must not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

R4.1.3. For planning events P1 through P7: Power oscillations must exhibit acceptable damping as established by the BA.

R4.2. Studies must be performed to assess the impact of the extreme events which are identified by the list created in R4.5.

R4.3. Contingency analyses for R4.1 and R4.2 must:

R4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses must include the impact of subsequent:

- Successful high speed (less than one second) reclosing and unsuccessful high-speed reclosing into a Fault where high speed reclosing is utilized.
- Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.
- Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.
- Tripping of all generation sources whose ride-thru capabilities are exceeded.

R4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static VAR compensators and power flow controllers.

R4.4. Those planning events in Table 1 that are expected to produce more severe system impacts on its portion of the system, must be identified, and a list created of those Contingencies to be evaluated in R4.1. The rationale for those Contingencies selected for evaluation must be available as supporting information.

R4.5. Those extreme events in Table 1 that are expected to produce more severe system impacts must be identified and a list created of those events to be evaluated in R4.2. The rationale for those Contingencies selected for evaluation must be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) must be conducted.

R5. The BA must have criteria for acceptable system steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its system. For transient voltage response, the criteria must at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level.

R6. The BA must define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify system instability for conditions such as Cascading, voltage instability, or uncontrolled islanding.

R7. The BA must distribute its Planning Assessment results to the Hawaiʻi PUC (or designee) within 30 calendar days upon a written request for the information.

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

1. The system must remain stable. Cascading and uncontrolled islanding must not occur.
2. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.
3. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.
4. Simulate Normal Clearing unless otherwise specified.
5. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings
6. Phase angle separation for line contingency must not preclude automatic reclosing for BA groups B and C, unless system Adjustments can be performed within fifteen minutes.

Steady State Only:

7. Applicable Facility Ratings must not be exceeded.
8. System steady state voltages and post-Contingency voltage deviations must be within acceptable limits as established by the BA.
9. Planning event P0 is applicable to steady state only.
10. The response of voltage sensitive load that is disconnected from the system by end-user equipment associated with an event must not be used to meet steady state performance requirements.

Stability Only:

11. Transient voltage response must be within acceptable limits established by the BA.

Category	Initial Condition	Event[1]	Fault Type[2]	Non-Consequential Load Loss Allowed	Range of Customers Loss Allowed	Applicable BA Groups[3]
P0 No Contingency	Normal system	None	N/A	No	None	A, B, and C
P1 Single Contingency	Normal system	Loss of one of the following: 1. Generator 2. Transmission Circuits 3. Transformer[4] 4. Shunt Device-Ancillary Service Device[5] 5. Generator – no fault	3Ø and SLG for Events 1 through 4, N/A for Event	Yes	Up to 12% generation only	A
				Yes	Up to 15% generation only	B
				Yes	Up to 15% generation only	C

Table 1 – Steady State & Stability Performance Planning Events—Continued						
Category	**Initial Condition**	**Event[1]**	**Fault Type[2]**	**Non-Consequential Load Loss Allowed**	**Range of Customers Loss Allowed**	**Applicable BA Groups[3]**
P2 Single Contingency	Normal system	1. Opening a line section w/o fault[6]	N/A	No	None	A, B, and C
		2. Bus Section fault	SLG	Yes	none	A
				Yes	none	B
				Yes	none	C
		3. Internal Breaker Fault[7] (Transmission line breaker)	SLG	Yes	none	A
				Yes	none	B
				Yes	none	C
P3 Single Contingency	Loss of generator unit followed by System adjustments[8]	Loss of one of the following: 1. Generator 2. Transmission Circuits 3. Transformer[4] 4. Shunt Device/ Ancillary Service Device[5]	3Ø and SLG	No	up to 12%	A
				Yes	up to 40%	B
				Yes	up to 40%	C

Table 1 – Steady State & Stability Performance Planning Events—Continued

Category	Initial Condition	Event[1]	Fault Type[2]	Non-Consequential Load Loss Allowed	Range of Customers Loss Allowed	Applicable BA Groups[3]
P4 Multiple Contingency (Fault plus stuck breaker[10])	Normal system	Loss of multiple elements caused by a stuck breaker[10] (non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuits 3. Transformer[4] 4. Shunt Device[5] 5. Bus Section	SLG	Yes	Up to 65%	A
				Yes	Up to 65%	B[13]
				Yes	Up to 65%	C[13]
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie breaker) attempting to clear a Fault on the associated bus	SLG	Yes	Up to 65%	A[13]
				Yes	Up to 65%	B[13]
				Yes	Up to 65%	C[13]

Table 1 – Steady State & Stability Performance Planning Events—Continued						
Category	**Initial Condition**	**Event[1]**	**Fault Type[2]**	**Non-Consequential Load Loss Allowed**	**Range of Customers Loss Allowed**	**Applicable BA Groups[3]**
P5 Multiple Contingency (Fault plus relay failure to operate)	Normal system	Delayed Fault Clearing due to the failure of a non-redundant relay[12] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuits 3. Transformer[4] 4. Shunt Device[5] 5. Bus Section	SLG	No	None	A
				Yes	Up to 15%	B
				Yes	Up to 15%	C
P6 Multiple Contingency (Two overlapping singles)	Loss of one of the followed by system adjustments[8] 1. Transmission Circuits 2. Transformer[4] 3. Shunt Device[5]	Loss of one of the following: 1. Transmission Circuits 2. Transformer[4] 3. Shunt Device[5]	3Ø	No	Up to 40%	A
				Yes	Up to 65%	B[13]
				Yes	Up to 65%	C[13]
P7 Multiple Contingency (Common Structure)	Normal system	The loss of any two adjacent (vertically or horizontally) circuits on common wood structure[10]	SLG	No	Up to 40%	A
				Yes	Up to 65%	B
				Yes	Up to 65%	C

<table>
<tr><th colspan="2">Table 1 – Steady State & Stability Performance Extreme Events</th></tr>
<tr><td colspan="2">Steady State & Stability

For all extreme events evaluated:

1. Simulate the removal of all elements that Protection systems and automatic controls are expected to disconnect for each Contingency.
2. Simulate Normal Clearing unless otherwise specified.</td></tr>
<tr><td>Steady State

1. Loss of a single generator, Transmission Circuit, shunt device, or transformer force out of service followed by another single generator, Transmission Circuit, shunt device, or transformer forced out of service prior to system adjustments.
2. Local area events affecting the transmission system such as:
a. Loss of a tower line with three or more circuits[10].
b. Loss of all Transmission lines on a common Right-of-Way[10].
c. Loss of a switching station or substation (loss of one voltage level plus transformers).
d. Loss of all generating units at a generating station.
e. Loss of a large load or major load center.
3. Wide area events affecting the Transmission System based on system topology such as:
a. Loss of two generating stations resulting from conditions such as:
i. Loss of a large fuel line into an area.
ii. Loss of the use of a large body of water as the cooling source for generation.
iii. Wildfires
iv. Severe weather, for example, hurricanes
v. A successful cyber attack
vi. Large earthquake, tsunami or volcanic eruption
b. Other events based upon operating experience that may result in wide area disturbances.</td>
<td>Stability

1. Loss of a single generator, Transmission circuit, shunt device, or transformer force out of service apply a 3Ø fault on another single generator, Transmission circuit, shunt device, or transformer prior to system adjustments.
2. Local area events affecting the transmission system such as:
a. 3Ø fault on generator with stuck breaker[9] or a relay failure[12] resulting in Delayed Fault Clearing.
b. 3Ø fault on Transmission circuit with stuck breaker[9] or a relay failure[12] resulting in Delayed Fault Clearing.
c. 3Ø fault on transformer with stuck breaker[9] or a relay failure[12] resulting in Delayed Fault Clearing.
d. 3Ø fault on bus section with stuck breaker[9] or a relay failure[12] resulting in Delayed Fault Clearing.
e. 3Ø internal breaker fault.
f. Other events based upon operating experience, such as consideration of initiating events that experience, such as consideration of initiating events that experience suggests may result in wide area disturbances.</td></tr>
</table>

Table 1 – Steady State & Stability Performance Footnotes (Planning Event and Extreme Events)
Footnotes 1. If the event analyzed involves system elements at multiple system voltage levels, the lowest system voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Non-Consequential Load Loss. 2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria. 3. The Applicable BA Groups (A, B or C) is defined under Facilities and is determined by the annual system peak demand. 4. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the system connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers. 5. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground. 6. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving load radial from a single source point. 7. An internal breaker fault means a breaker failing internally, thus creating a system fault which must be cleared by protection on both sides of the breaker. 8. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Transmission following Contingency events. System adjustment (as identified in the column entitled 'Initial Condition') when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered. 9. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing. 10. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less. 11. An objective of the planning process should be to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency events. However, in limited circumstances Non-Consequential Load Loss may be needed to address System performance requirements. When Non-Consequential Load Loss is utilized within the planning process to address system performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss is documented, including alternatives evaluated. 12. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32 & 67), and tripping (#86 & 94). 13. Indicates that the system level for the Category is an extreme event for the Group.

C. Measures

M1. The BA must provide evidence, in electronic or hard copy format, that it is maintaining system models within their respective area, using data consistent with HI-MOD-010 Development and Reporting of Steady State System Models and Simulations and HI-MOD-012 Development and Reporting of Dynamic System Models and Simulations, including items represented in the Corrective Action Plan, representing projected system conditions, and that the models represent the required information in accordance with R1.

M2. The BA must provide dated evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the system in accordance with Requirement R2.

M3. The BA must provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.

M4. The BA must provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.

M5. The BA must provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable system steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its system in accordance with Requirement R5.

M6. The BA must provide dated evidence, such as electronic or hard copies of documentation specifying the criteria or methodology used in the analysis to identify system instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

M7. The BA must provide evidence, such as email notices, postal receipts showing recipient and date that it has distributed its Planning Assessment results to the Hawaiʻi PUC (or designee) within 30 calendar days upon a written request for the information in accordance with Requirement R7.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

Hawai'i PUC (or designee).

1.2. Data Retention:

The BA must each retain data or evidence to show compliance as identified unless directed by its Hawai'i PUC (or designee) to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current in-force Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.
- The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.
- The documentation specifying the criteria for acceptable system steady state voltage limits, post-contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5.
- The documentation specifying the criteria or methodology utilized in the analysis to identify system instability for conditions such as cascading, voltage instability, or uncontrolled islanding in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.
- Three calendar years of the notifications employed in accordance with Requirement R7 and Measure M7.

If the BA is found non-compliant, it must keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.

1.3. Compliance Monitoring and Enforcement Processes:

- Compliance Audits: The Hawai'i PUC (or designee) will give notice to the BA within 30 days of years' end for a compliance audit and will complete such audit within 90 days of such information being supplied by the BA.
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

2. Levels of Non-Compliance for Requirement R1, Measure M1:

2.1. Level 1: The BA's system model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.5. for Requirement R1 and Measurement M1.

2.2. Level 2: The BA failed to meet all the requirements of Level 1 for Requirement R1 and Measurement M1.

3. Levels of Non-Compliance for Requirement R2, Measure M2:

3.1. Level 1: The BA failed to comply with Requirement R2, Part 2.6. for Requirement R2 and Measurement M2

3.2. Level 2: The BA failed to meet all the requirements of Level 1 for Requirement R2 and Measurement M2.

4. Levels of Non-Compliance for Requirement R3, Measure M3:

4.1. Level 1: The BA did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement R3, Part 3.5. for Requirement R3 and Measurement M3.

4.2. Level 2: The BA failed to meet all the requirements of Level 1 for Requirement R3 and Measurement M3.

5. Levels of Non-Compliance for Requirement R4, Measure M4:

5.1. Level 1: The BA did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5 for Requirement R4 and Measurement M4.

5.2. Level 2: The BA failed to meet all the requirements of Level 1 for Requirement R4 and Measurement M4.

6. Levels of Non-Compliance for Requirement R5, Measure M5:

   6.1. Level 1: N/A

   6.2. Level 2: The BA does not have criteria for acceptable system steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its system for Requirement R5 and Measurement M5.

7. Levels of Non-Compliance for Requirement R6, Measure M6:

   7.1. Level 1: N/A

   7.2. Level 2: The BA failed to define and document the criteria or methodology for system instability used within its analysis as described in Requirement R6 for Requirement R6 and Measurement M6.

8. Levels of Non-Compliance for Requirement R7, Measure M7:

   8.1. The BA distributed its Planning Assessment results to Hawaiʻi PUC (or designee) but it was more than 30 days but less than or equal to 40 days following the request as described in Requirement R7 for Requirement R7 and Measurement M7.

   8.2. The BA failed to meet all the requirements of Level 1 for Requirement R7 and Measurement M7.

BAL-502-0: RESOURCE ADEQUACY ANALYSIS, ASSESSMENT, AND DOCUMENTATION

A. Introduction

Purpose: To establish common criteria for each Balancing Authority (BA) based on "one day in *x* year" (determined by study) loss of load expectation principles or as an alternative a planning methodology based on the single largest unit contingency and an appropriate reserve margin or reserve criteria. The analysis, assessment and documentation of Resource Adequacy, will include Planning Reserve Margins for meeting system load for the BA's system. The analysis will also include resource adequacy analysis for frequency response, spinning reserve, off-line reserves and other resource characteristics required to meet the reliability criteria.

Applicability: Balancing Authorities (BA) are divided into two groups based on the annual system Peak Demand.

- Group A: Annual system peak is greater than 50 MW.
- Group B: Annual system peak is less than or equal to 50 MW.

Effective Date: To be determined

B. Requirements

R1. The Group A utilities will establish at their discretion whether to use Resource Adequacy analysis using requirements defined in either R1.1 or R1.2 for each planning year. Group B will use the planning methodology defined in R1.2 for each planning year.

R1.1. Group A: "one day in *x* year criteria". The utility will establish the methodology and procedures used to establish the "one day in *x* year" criteria to meet the system peak load to be served by the BA. The methodology should evaluate the reliability of the generating resources, the capacity and system requirements of the BA and the alternatives to resource commitment available to meet the desired reliability criteria for each of the BA's utility loss of load expectations methodologies. In addition the methodology should include the consideration of, renewable capacity from as-available renewable resources using the reliability based methods described in R1.2 for L_{QC}. Consideration will also be given to ensure that the enough generating resources are installed on system that have the capability to provide the operating ancillary services such as frequency response, spinning reserve, voltage regulation, frequency regulation and other services during the same time periods included in HI-TPL-001 Transmission Planning Performance Requirements as follows:

R1.1.1. Minimum day load with no as-available renewable generation

R1.1.2. Minimum day load with as-available maximum renewable generation

R1.1.3. Maximum load with no as-available renewable generation

R1.1.4. Maximum load with maximum as-available renewable generation.

R1.2. Group A and Group B: "reserve margin of *xx*% criteria". The utility will maintain a minimum *xx*% Reserve Margin (F_{RM}) over the annual system peak.

$$\frac{\sum_{i=1}^{N} N_i + L_{DR} + L_{QC} - L_{Peak}}{L_{Peak} - L_{DR}} \geq F_{RM}$$

Where:

- F_{RM} is the Reserve Margin.
- N_i is the Normal Net Capability of all firm units.

- L_{DR} is the amount of Interruptible Demand and Direct Control Load Management (DCLM) exclusively available and measureable for the BA's interruption for the entire period of the expected capacity shortfall. Such Interruptible Demand and DCLM will not infringe on the protective reserve for system security required by HI-BAL-006 Underfrequency Load Shedding.
- L_{QC} is the estimated capacity value of grid-side as-available renewable and stored energy generation on the system. The estimated capacity value of grid-side as-available generation and stored energy will be determined by the utility using reliability or statistical based calculation methods depending upon the available data. Reliability based methods that may be used include the effective load carrying capability (ELCC), equivalent conventional power (ECP), or equivalent firm capacity (EFC) methods. Statistical based methods may consist of the relevant time period of the system peak and renewable energy over a time series of data. For example, the estimated capacity L_{QC} is the level where over that system peak period in which 90% of the data points are available to serve the system peak. For existing installations, the capacity value will be calculated using three years of actual data for each group of similar as-available renewables such as wind, hydro, PV, etc. For future installations the estimated capacity value will be based on estimated capacity value calculations for similarly located resources installed in Hawaiʻi. For future as-available resources where no Hawaiʻi historical data is available, the best available data shall be used for calculations. For the first year of data, the estimated capacity value shall be adjusted by 0.7 followed by 0.8 after gathering the second year of data. Following the third year of data, the actual data shall be used to determine the capacity value.
- L_{Peak} is the forecasted annual system peak load.

The Reserve Margin analysis will also consider as a secondary planning criteria that the BA's total Normal Net Capability of all firm units of the system less the capacity of the unit(s) scheduled for maintenance less the capacity that would be lost by the Forced Outage of the largest single contingency plus the total amount of interruptible loads plus the estimated capacity value of grid-side as-available renewable and stored energy generation on the system, if appropriate, and dedicated for serving the entire period of the peak ,must be equal to or greater than the forecasted system peak load.

$$\sum_{i=1}^{N} N_i - \sum_{m=1}^{N} N_m - N_{FO} + L_{DR} + L_{QC} \geq L_{Peak}$$

Where:

- N_m is the Normal Net Capability of units on scheduled maintenance.
- N_{FO} is the Normal Net Capability of the largest single contingency lost by Forced Outage.

R1.3. The BA for each Group A system will stipulate the use of either R1.1. or R1.2. for planning. The Resource Adequacy analysis must calculate a Planning Reserve Margin for the applicable group that will either result from the sum of the probabilities for Loss of Load for the system Peak Demand for all days of each planning year analyzed (per R1.1) being equal to *xx*. (This is comparable to a “one day in *x* year” criterion) or document that the applicable Balance Authority has developed a resource plan that encompasses a *xx*% Reserve Margin for Group A (per R1.2). Group B will use the Reserve Margin criteria (per R.1.2). The reserve margin target will be utilized until such a time that a new study determines a change in the reserve margin is warranted.

R1.4. The BA will develop criteria to ensure the generation characteristics address the following system requirements:

R1.4.1. Starting and loading time if resources are to be used as Contingency Reserves as required in HI-BAL-002 Disturbance Control Standard.

R1.4.2. The Frequency and Inertia response characteristics as required in HI-BAL-001 Transmission System Planning Performance Requirements.

R1.4.3. The Voltage and Frequency ride-through characteristics as required in HI-BAL-001 Transmission System Planning Performance Requirements.

R1.4.4. Short circuit current requirements.

R1.4.5. Dispatch characteristics (starting time, ramp rate, minimum values, regulation, etc.) as required to meet the requirements of the planning period.

R1.4.6. Any other ancillary resources required to meet system security requirements which have been identified as necessary through analysis of the planning period.

R1.5. Be performed or verified separately for each of the following planning years:

R1.5.1. Perform an analysis for Year One.

R1.5.2. Perform an analysis or verification when changes in measured non-dispatchable generation or net load changes more than *x* MW/year or *x* MW (amount established by each BA) from Year One or there are planned or unplanned changes in resource development other than nondispatchable generation or DG.

R1.6. Include the following subject matter and documentation of its use:

R1.6.1. Criteria for including planned resource additions in the analysis.

R1.6.2. Load forecast characteristics:

- Median forecast peak load.
- Load forecast uncertainty (reflects variability in the load forecast due to weather and regional economic forecasts).
- Load diversity.
- Seasonal load variations.
- Daily demand modeling assumptions (firm, interruptible).
- Contractual arrangements concerning curtailable or Interruptible Demand.
- Historic resource performance and any projected changes.

Seasonal resource ratings.

- Historic resource performance and any projected changes.

Seasonal resource ratings.

- Resource planned outage schedules, deratings, and retirements.
- Intermittent and energy limited resources such as wind, PV, and cogeneration may be considered holistically using time synchronized data with load. The relevant time period of the system peak must be defined using a minimum of three years of data.

R1.6.3. Transmission limitations that prevent the delivery of generation reserves.

R1.6.3.1. Criteria for including planned Transmission Facility additions in the analysis.

R1.6.3.2. Criteria for remedial action systems employed in lieu of Transmission improvements.

R1.7. Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included:

- Common mode outages that affect resource availability.
- Environmental or regulatory restrictions of resource availability.
- Any other demand (load) response programs not included in R1.3.1.
- Sensitivity to resource outage rates.
- Impacts of extreme weather or drought conditions that affect unit availability.

R1.8. Document that capacity resources are appropriately accounted for in its Resource Adequacy analysis.

R2. The BA must annually document the projected load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis.

R2.1. This documentation must cover each of the years in Year One through ten.

R2.2. This documentation must include the Planning Reserve Margin calculated per requirement R1.1 for each of the three years in the analysis.

R2.3. The documentation as specified per requirement R2.1 and R2.2 must be publicly posted no later than 30 days after the close of the year.

C. Measures

M1. The BA must possess the documentation that a valid Resource Adequacy analysis was performed or verified in accordance with R1.

M2. The BA must possess the documentation of its projected load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis on an annual basis in accordance with R2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

1.1.1. Hawai'i PUC (or designee)

1.2. Compliance Monitoring Period and Reset Timeframe

1.2.1. One calendar year

1.3. Data Retention

1.3.1. The BA must retain information from the most current and prior two years. The Hawai'i PUC (or designee) will retain any audit data for five years.

2. Levels of Non-Compliance for Requirement R1, Measure M1:

2.1. Level 1: The BA met one of the following conditions for Requirement R1 and Measurement M1.

2.1.1. The BA Resource Adequacy analysis failed to consider 1 or 2 of the Resource availability characteristics subcomponents under R1.4 and documentation of how and why they were included in the analysis or why they were not included.

2.1.2. The BA Resource Adequacy analysis failed to consider Transmission maintenance outage schedules and document how and why they were included in the analysis or why they were not included per R1.6.

2.2. Level 2: The BA failed to meet all the requirements of Level 1 for Requirement R1 and Measurement M1.

3. Levels of Non-Compliance for Requirement R2, Measure M2:

3.1. Level 1: The BA failed to publicly post the documents as specified per requirement R2.1 and R2.2 later than 30 calendar days prior to the beginning of Year One per R2.3 for Requirement R2 and Measurement M2.

3.2. Level 2: The BA failed to meet all the requirements of Level 1 for Requirement R2 and Measurement M2. The PUC or its designee will give notice to the BA within 30 days of years' end for a compliance audit and will complete such audit within 90 days of such information being supplied by the BA.

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N. System Operation and Transparency of Operations

PRUDENT DISPATCH AND OPERATIONAL PRACTICES

The Companies' unit commitment and economic dispatch policies are based on safe and reliable operation of the system, minimizing operating costs, and complying with contractual and regulatory obligations. The daily generation dispatch process is illustrated in Figure N-1.

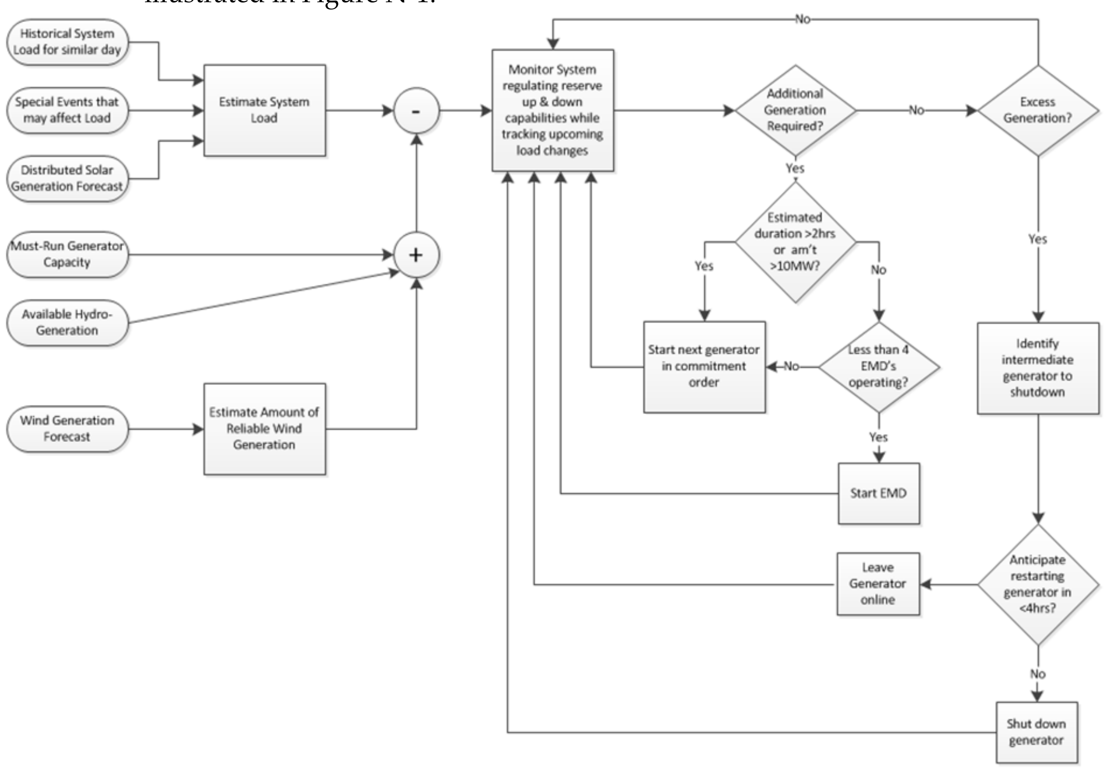

Figure N-1. Daily Generation Dispatch Process

In the future, the goal is for the System Operator to be able to incorporate a more automated approach to unit commitment and dispatch with increased amounts of variable renewable generation (wind and solar), quick-starting engines, energy storage, and demand response resources on the grid. The Energy Manage Systems (EMS) would likely be interfaced/integrated with corresponding Demand Response Management Systems (DRMS) and Energy Storage Management Systems (ESMS). This would also include integrating the demand forecast, with wind and solar forecasts to achieve a net demand to be used for unit commitment.

Minimization of Ancillary Services Costs

The process to identify system security constraints, and the combinations of resources which can be used to meet them, is summarized as follows:

- Determine system constraints.
- Identify the resource mix that meets each of them.
- Select the lowest cost combination of resources to operate.

For all three operating companies, additional security constraints are imposed with increased concentrations of variable renewable resources. Therefore, the projected increase in distributed PV may have an impact on ancillary service costs. The Companies will continually evaluate the economics of using existing resources to meet ancillary service and system security requirements versus meeting those needs with alternative resources including energy storage and demand response.

Maximizing the Use of Available Renewable Energy

The commitment and dispatch of renewable energy resources depends upon the contract terms for those resources and whether or not the system operator has visibility and control over the generation. If the resource can be economically dispatched, it is put under automatic generation control (AGC), and its output is determined by its marginal cost relative to the marginal cost of other resources. Examples of this type of renewable resource includes geothermal, generating units using renewable biofuels, waste-to-energy projects, and other "firm" renewable projects.

To date, variable renewable energy projects are contractually treated as "must-take," variable energy. These resources are accepted regardless of cost, but their output is reduced as needed when all intermediate units are off line and there remains excess energy production. In this case the system operator limits, or "curtails" the output of variable energy providers to the degree necessary to keep the system in balance and provide response reserves. Most curtailments are partial—the output is limited but the resource is not restricted to zero output. When curtailment is necessary due to excess energy, it is performed in a manner consistent with the purchased power agreements associated with the affected resources and in accordance with a priority order established by the system operator.

In addition to excess energy situations, curtailments can also be required for system constraints such as line loading, phase angle separation, line maintenance, and frequency impact from power fluctuations. Curtailments for system constraints are applied to the resources as needed to address these constraints and are not subject to the priority order used for excess energy curtailments. Curtailments are also performed at the request of wind plants for wind conditions, and equipment issues. The number of curtailment events, the reason, and their duration are reported monthly through various reports to the Commission such as the monthly report filed by the Hawaiian Electric Companies in Docket No. 2011-0206 (RSWG).

The vast majority of distributed solar PV is not visible or controllable by the system operator. These resources serve demand ahead of all other resources. Additional growth in distributed solar PV these resources is forecast to cause increased curtailments of utility-scale variable renewable resources, unless distributed solar PV is required to provide the visibility and control to the system operator.

Energy Management Systems (EMS)

The operation of the system is facilitated by use of a centralized Energy Management System (EMS). The EMS provides the system operator with constantly updated, real-time information about the operational state of the system. There are three key program applications within the EMS:

- Supervisory Control and Data Acquisition (SCADA)
- Real-time Automatic Generation Control (AGC)
- Real-time State Estimator

The Companies routinely update the EMS hardware and software platforms for each system in order to ensure reliable operation, to incorporate new industry developments such as protocols and system security measures, and to maintain support from EMS vendors[1]. The most recent migration to a new platform was completed in late 2013.

[1] The Companies operate EMS systems from two different vendors, *Alstom* at Hawai'i Electric Light and Maui Electric, and *Siemens* at Hawaiian Electric.

System Dispatch and Unit Commitment

Unit commitment and dispatch decisions are based upon:

Safety. The Companies' dispatch of generating resources is always subject to ensuring the safety of Company personnel and the general public.

Reliability. Dispatch and unit commitment must adhere to system security and generation adequacy requirements.

Contractual Requirements. Dispatch and unit commitment must adhere to contractual constraints.

Cost. After meeting all the forgoing requirements, the Company commits units and dispatches units based on their marginal cost, with lower cost units being committed and operated before higher cost units.

When determining the unit commitment and dispatch of generating units, the Company does not differentiate between dispatchable IPPs and utility-owned assets. The daily unit commitment modeling tool input date does not differentiate units by ownership. Certain generators do receive a form of priority in terms of energy being accepted onto the system on the basis of the location of the generator, its characteristics, or the contractual obligations unique to the resource. The acceptance of energy is in the following order of preference:

- **Distributed generation:** Distributed generation resources receive preferential treatment as "must take" resources regardless of their economic merit for system dispatch. This includes Standard Interconnection Agreement (SIA) distributed generation and Net Energy Metering (NEM) distributed generation. At the present time, the Companies have no control over, or ability to curtail, distributed generation.
- **Scheduled contractually obligated generation:** These resources are preferentially treated from a dispatch perspective by contract. They are used to serve customer load regardless of their economic merit for system dispatch. Scheduled energy from these resources is taken after distributed generation, but ahead of all other resources including variable energy providers.
- **Contractually must-run, dispatchable generation:** The resources cannot be cycled offline and therefore the minimum dispatch level of these resources are preferentially treated in the system dispatch determination and the energy is accepted from these resources regardless of cost, except during periods of maintenance.
- **Generation to meet system security constraints:** These resources provide energy at least at their minimum dispatch limit, ahead of other resources, similar to contractual must-run and scheduled generation, plus an amount of reserve capability to provide down regulation. However, once dispatched, the continued operating status of these

resources is subject to continual evaluation of their costs relative to other alternative resources that may become available at a lower cost, except where it is required by contract.

- **Variable energy:** As available energy is accepted on the system, regardless of cost, after distributed generation, scheduled energy purchases, and continuously operated generation. This energy is accepted regardless of cost and thus presents a constraint on optimized (lowest) cost. If the energy cannot be accommodated due to low demand, curtailment of the resource is ordered according to an established and approved priority order.
- **Dispatchable resources:** Energy from dispatchable resources is taken on the basis of relative cost (economic dispatch). Resources with the lowest variable energy (fuel and O&M) cost will be committed ahead of resources with higher variable costs. Online resources with lower incremental costs will be dispatched at higher outputs ahead of resources with higher incremental costs. The units operated routinely to meet demand, but cycled offline during minimum demand periods, are described as intermediate units. Short-term (daily) unit commitment decisions do not consider fixed costs associated with these resources because the fixed costs will be incurred regardless of whether or not the unit is operated.

Utilization of Energy Storage and Demand Response

Energy storage and demand response programs 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 assets will be equipped with essentially the same telemetry and controls necessary to operate generating units. Demand response used for providing regulation reserves and contingency reserves will also be equipped with appropriate telemetry and controls. The specific interface requirements depend upon whether the storage device or demand response resource is responding automatically, or is under the control of the system operator. DRMS and/or ESMS may be interfaced with or directly incorporated in an EMS. For storage or demand response that is integrated into the EMS, telemetry requirements include:

- For storage, real-time telemetry indicating charging state, amount of energy being produced, device status.
- Control interface to the EMS to enable the increase and decrease of energy output from the storage asset, and for energy input to the storage device for charging.
- For demand response, real-time telemetry indicating breaker status, switch status, and load.

- Control interface to the EMS to enable the triggering of load shed in response to automatic signals (for example, underfrequency) or a command from the system operator.

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. In order for the value of the demand response to be realized in providing a particular grid service, once called, the load cannot return to the system until after a specified time, which is dependent on the type of grid service being provided by the demand response resource. Accordingly, the system operator similarly requires information regarding the status of demand response, particularly as it relates to the state of the response after an event has been triggered.

Visibility and Transparency in System Dispatch

A high level review of the Renewable Watch websites of various ISOs including PJM, MISO, Cal ISO, and ERCOT shows the following operational information commonly being displayed, along with ISO energy market-specific information such as locational marginal pricing:

- Real time daily demand curve showing actual and forecasted demand, updated at least hourly
- Hourly wind power MW or MWh being produced and forecasted
- Other renewable energy production in MW (California)
- Available generation resources

The Company's Renewable Watch site currently displays the following information, with data updated approximately every 30 minutes:

Net Energy System Load. The system load served by generators on the "utility-side" of the meter including those owned by the utility and by independent power producers (IPP).

Gross System Load. The net system load plus estimated load served by "customer-side" of the meter by DG-PV.

Solar Irradiance Data. This data is measured in different regions of the island, which are used as input to calculating the estimated load served by customer-side PV.

Wind Power Production. Total megawatts of wind power being produced by the various IPP-owned wind farms selling electricity to Hawaiian Electric.

To provide further information to customers about the dispatch of various energy generation resources under the utility's control, the Company is currently partnering with the Blue Planet Foundation to develop and publicly present real time breakouts of the percentage of net energy system load being served by various fuel types, including coal, oil, wind, waste-to-energy, solar, and biofuel. Hawaiian Electric and Blue Planet believe this information will be useful in raising customer awareness of the use of renewable energy versus fossil fuels. A prototype kiosk was displayed at the Hawai'i Clean Energy Day event on July 22, 2014 with positive public reaction.

In light of this information already being developed for public display, Hawaiian Electric is agreeable to the following enhancements to its website:

- The information on the Renewable Energy watch website will be supplemented with additional information showing for the previous hour the percentage of the energy supplied by the different resources (IPPs, Renewables, Company generating units).
- A historical archive of the percentage of the energy produced by each of the resource groups for the previous 24 hour period will be maintained so that the customer can view the changes over time.

These enhancements will address the Commission's objectives of showing the significant use of non-utility generation and renewable resources, most of which, with the exception of Hawaiian Electric's biofueled combustion turbine generation CT-1, are IPP owned.

In addition to the above, Hawaiian Electric will also make public a description of its economic dispatch policies and procedures, via posting on its company website. Combined, the enhancements to the Hawaiian Electric website and the sharing of its dispatch policies and procedures will increase visibility and transparency of how generating resources are being dispatched on the Hawaiian Electric system.

As previously mentioned the Companies generating unit commitment and dispatch of the generating units is based on the objective of incurring the least cost to the customers while continuing to maintain system reliability. With the introduction of increasing amounts of renewable resources on the systems, it has become more important to minimize the use of fossil fuels and contending with the dynamic system changes that occur from the new resources so that reliability can be maintained. A screenshot from the Renewable Watch–O'ahu website is shown below in Figure N-2 to provide an example of the variability of the renewable energy resources.

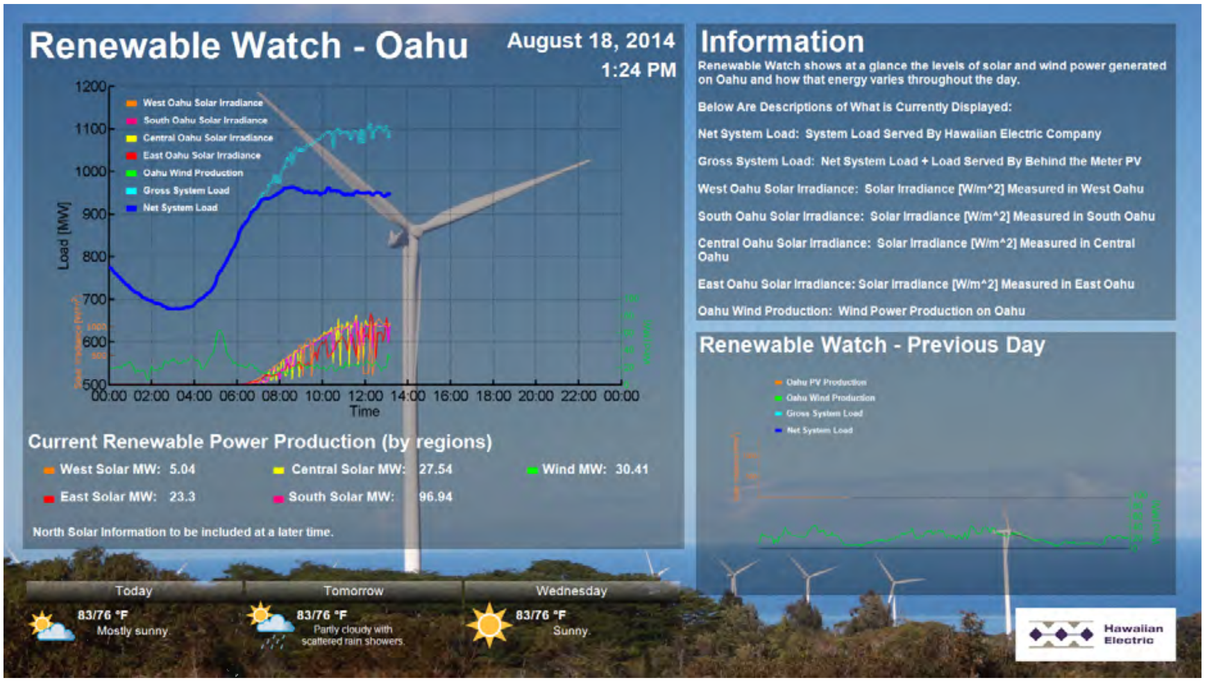

Figure N-2. Renewable Watch–O'ahu Website Screenshot of Information Displayed for August 18, 2014.

Keep in mind that the changes that have been occurring on the Companies' respective systems have been occurring for a few years but at different rates of change. The neighbor island systems (Maui and Hawai'i Island) have been changing at a far more rapid pace due to the high availability of renewable resources that could be used on each island.

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. Because wind and solar are variable resources, determining its capacity value becomes a considerable challenge in order to achieve the confidence required to include variable generation resources to replace firm generation.

Capacity Value of Wind Generation

Hawaiian Electric

The contribution of existing and future wind resources to capacity planning is reflected in the Loss of Load Probability (LOLP) analysis. In the modeling determination of when additional firm capacity may be needed based on the application of Hawaiian Electric's generating system reliability guideline (4.5 years per day), the wind resources' contribution to serving load will be reflected in the LOLP calculations. As such, wind resources' contribution to capacity planning is dependent upon the composition and assumptions in each plan.

Hawaiʻi Electric Light

The aggregate value of the two existing wind farms (20.5 MW Tawhiri wind generating facility and 10.56 MW Hawi Renewable Development wind farm) contribution to capacity planning is 3.1 MW.

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

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.

The capacity value of future wind farms in the PSIP is 3% 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.

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, and Customer Firm Generation Programs are included in PISP capacity planning.

CONCLUSIONS

The Companies understand the importance of visibility and transparency of the economic commitment and economic dispatch to show the customers that a real effort is being made to reduce the use of fossil fuels and to encourage the use of renewable resources. Creating a website with the same information that RTOs or ISOs use to show price of energy for the market may be misleading if the customer is unaware of the system conditions that is dictating how the generating units are being run. The information that is graphically displayed on the existing Renewable Watch websites is a good starting point for creating visibility and transparency. And the Companies recommend that additional information that is being developed by Blue Planet that displays the system load and the percent of power that each resource group is providing to serve that load also be shown to the customers so that they are able to see over time that less fossil fuel generation is being substituted with less costly generation.