Hawaii
Renewable Portfolio Standards Study

Submitted to the

U.S. Department of Energy
Office of Electricity Delivery and Energy Reliability

Under Cooperative Agreement No. DE-EE0003507
Hawai‘i Energy Sustainability Program

Task 2: Energy Modeling and Scenario Analysis

Prepared by

GE Energy Consulting

Submitted by

Hawai‘i Natural Energy Institute
School of Ocean and Earth Science and Technology
University of Hawai‘i

June 2015

Acknowledgement: This material is based upon work supported by the United States Department of Energy under Cooperative Agreement Number DE-EE0003507. Additional support was provided by the Hawaii Natural Energy Institute via the State of Hawaii, Energy Systems Development Special Fund.

Technical Report

Hawaii

Renewable Portfolio Standards Study

Prepared for: Hawaii Natural Energy Institute
Prepared by: GE Energy Consulting
Date: May, 2015

Foreword

This report was prepared by General Electric International, Inc. ("GEII"); acting through its Energy Consulting group ("GE Energy Consulting") based in Schenectady, NY, and submitted to the Hawaii Natural Energy Institute. Questions and any correspondence concerning this document should be referred to:

Technical Questions

Harjeet Johal
Principal
GE Energy Consulting

General Electric International, Inc.
20547 Warburton Bay Square
Sterling, VA 20165
Phone: (703) 962-7935
E-Mail: harjeet.johal@ge.com

Derek Stenclik
Senior Consultant
GE Energy Consulting

General Electric International, Inc.
2500 Austin Drive
Charlottesville, VA 22911
Phone: (434) 978-5052
E-Mail: derek.stenclik@ge.com

Commercial Questions

Denise Benoit
Contract Risk Manager
GE Energy Consulting

General Electric International, Inc.
One River Road
Building 53-311A
Schenectady, New York 12345
Phone: (518) 385-0901
Fax: (518) 385-5703
E-Mail: denise.benoit@ge.com

Project Team

Hawaii Natural Energy Institute

Richard Rocheleau

John Cole

General Electric

Harjeet Johal

Derek Stenclik

Gene Hinkle

Richard Piwko

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

1 KEY FINDINGS AND RECOMMENDATIONS

It must be stated that several factors related to this study are different today than at the time this project began over eighteen months ago:

Hawaii's RPS Law

- Currently the RPS requires 25% of utility electricity sales be represented by renewable energy by 2020, and 40% by 2030.
- The 2015 Hawaii Legislature passed House Bill 623 (awaiting Governor signature), which would increase the RPS to 30% by 2020, 40% by 2030, 70% by 2040, and 100% by 2045.
- The eighteen scenarios analyzed in this study were developed to evaluate representative combinations of renewable energy additions that would achieve and surpass the 25% by 2020 RPS target and provide
  - The amounts of wind, utility scale solar, and distributed solar energy chosen for the scenarios were selected to evaluate possible resource mixes necessary to meet RPS targets. They are not meant to represent system limits nor are they meant to imply a limitation of the resource on an individual island. This will be addressed in follow-on work.
  - While the study included existing or near-term committed firm renewable generation, the scenarios focused on the growth of solar and wind. This was done to make it easier to compare the impacts of the various scenarios. It was assumed that the addition of new firm renewable generation resources, e.g. biofuels or biomass, would not substantially impact system operation and reliability issues, and could therefore be a direct replacement for additional fossil fuel. If additional firm renewable resources become available, it is a straightforward calculation to determine the increased contribution to delivered renewable energy and the RPS.

Cost Assumptions

- In contrast to previous studies, this work attempted to assess not only the production cost saving but also the costs associated with the integration of additional renewables. Details of these calculations are in the report. All cost numbers are presented in 2013 dollars. For calculation of the cost production, fuel price assumptions used in the study were in HECO's integrated resource plan filed with the Hawaii Public Utilities Commission in June of 2013.
- Since the time of that filing, oil prices have fallen substantially from approximately $100/barrel in Q2 2013 to $60/barrel today. This means that production cost information, including savings from using renewable energy resources and switching from using petroleum to LNG for thermal generation, are overstated in terms of the oil prices at the time of publication of this report. However, it must be kept in mind that the study is looking out at the year 2020, and at that time, the fuel price forecast could be more or less accurate than what it seems today.

Fuel price sensitivities and/or hedging cost calculations can be added to current and future modeling efforts to determine the effects of possible different fuel prices.

Key Findings and Recommendations

The Hawaiian islands of Oahu and Maui can achieve greater than 40% renewable energy penetration and can surpass the 2030 RPS goals. Certain modifications will be required to effectively accommodate these new renewable energy resources while lowering the cost of electricity and improving the reliability of the grid. In addition, the operational stability of the grid may also be challenged at these renewable energy penetration limits. To evaluate this impact, detailed stability analysis is currently underway on the high renewable energy scenarios assessed in this study. The findings from this analysis will suggest recommendations to improve the stability of the island grids and will be reported separately.

The following recommendations suggest different pathways that the island grids can take to improve the operational economics while being able to accommodate very high levels of renewable energy:

- Balanced growth of renewable resources: Diversity in generation resource mix will enable the island grids to continue increasing levels of renewable energy, at a lower cost of electricity while maintaining reliability. A balanced growth of available renewable resources will help to reduce the aggregate variability and intermittency, and the associated requirement for ancillary services on the grid.

- Improving grid flexibility: The island power grids, in general, require increasing flexibility to accommodate the intermittency and variability of wind and solar resources. New operational protocols and infrastructural upgrades will be required to ensure that the grid can respond effectively to meet the net load requirement and variability. This can be achieved through appropriate changes in the commitment and dispatch procedures, new infrastructure that will enable the existing generation to cycle up and down or on and off daily, new controls that can enable the thermal generators to be turned down lower, and additional ancillary services.

- Natural Gas as the primary fuel for the islands: Delivering liquid natural gas can be a highly successful measure for lowering the cost of electricity as the islands transition to increased levels of renewable energy. The beneficial rate impact, however, depends critically on the contract price to bring LNG to the Hawaiian Islands. The delivered LNG price is dependent on the quantity in the contract and results of this analysis indicate that the consumption of natural gas can decrease by up to 33% as the renewable energy penetration reaches 50%. Under the current LNG price forecast (based on HECO's 2013 Integrated Resource Plan), the cost of electricity on the islands can be reduced by up to 28% under high renewable energy scenarios.

- Infrastructure for improving grid reliability: With the planned retirements of units in the coming years, the Oahu grid reliability will be degraded from existing levels. New wind and solar generation will provide limited benefits in improving reliability and generation adequacy. The system planners must therefore evaluate other alternatives for meeting the reliability needs, including new thermal generation, energy efficiency, demand response, and possibly island interconnection. Meeting the 2020 energy efficiency targets or achieving the full demand response potential will enable the Oahu grid to increase reliability levels well above the minimum requirement even after the proposed thermal generator retirements. However, if demand response is utilized heavily for reliability goals, it must be ensured to be available when needed and for the full duration of time required.

- Island interconnection facilitates increased renewable penetration and resource sharing: Interconnecting the islands will assist in sharing the resources more effectively: when Oahu is short on generation, Maui may assist in shipping the needed MWs across the cable and vice versa. This will help to improve the reliability and generation adequacy of both Oahu and Maui. In addition, the combined electrical grids will be able to accommodate higher levels of wind and solar energy by allowing the energy to flow through the cable. Diversity in generation resource mix and load profiles may further help in lowering the cost of operations. However, the interconnections require significant levels of capital expenditures and are therefore highly sensitive to financing costs, fuel price assumptions, and other economic variables.

2 INTRODUCTION

2.1 Study Objectives

Hawaii is at the forefront of renewable energy integration and has one of the fastest growing renewable energy sectors in the electric power industry. Furthermore, Hawaii is integrating high levels of wind and solar energy on a system that is comprised of multiple isolated island grids, which poses unique challenges for grid operations and reliability of energy supply. Given the state's reliance on imported fossil fuels and a history of environmental stewardship, Hawaii has strong incentives to continue increasing renewable integration across the state. As a result, Hawaii's Renewable Portfolio Standards (RPS) outlines ambitious future renewable energy goals. By 2020 over 25% of the State's electricity must be generated by renewable sources, a target that increases to 40% by 2030.

While the goals and targets are clear, the methods of achieving these targets are uncertain. Various proposals from many stakeholders have been analyzed. In 2013 the state's electric utility, Hawaiian Electric Company, released an Integrated Resource Plan outlining the utility's future plans and proposed investments. A year later, the utility also released the Power Supply Improvement Plant (PSIP) report outlining specific actions the utility was planning to take to accommodate increased renewable penetration and distributed energy resources. While progress has been made to achieve high levels of renewable penetration (the 2015 RPS target of 15% renewable penetration was achieved before the target deadline), accommodating additional renewable energy will be increasingly challenging relative to past experience. This is especially true for variable sources such as wind and solar PV. Hawaii's energy future is currently at a pivotal crossroads. Decisions and investments made in the near future will have long-lasting effects to Hawaii's energy future.

The purpose of this study was to identify and evaluate cost-effective pathways that support the growth of renewables on Oahu and Maui with a goal of achieving the RPS targets. Unlike previous renewable integration studies conducted in Hawaii, this study was designed to be holistic in scope, encompassing a broad spectrum of power system operations, economics, and reliability impacts associated with high levels of renewable penetration. The study evaluated many different resource mixes including varying amounts of utility scale wind and solar, as well as increasing amounts of distributed rooftop solar PV. These resource mixes were evaluated with and without transmission and grid configurations that interconnect Oahu and Maui, as well as other off-island resources.

This study also evaluated the impact of recent and proposed changes to the power system, including conventional thermal plant additions and retirements, changing to the primary fuel to liquefied natural gas, and other changes being implemented by the utility. Wherever possible, this study quantified the impacts of these changes on the electric power system, with specific emphasis on renewable energy penetration, wind and solar curtailment, system economics, and grid reliability.

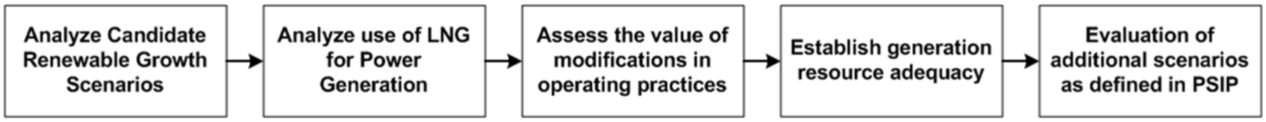


Figure 1: Project Tasks and Analysis Flow Chart

The major project tasks are summarized in Figure 1. While the core analysis of this study was highly technical in nature, this report is intended to summarize the key findings and recommendations in a concise and simplified manner. The main body of this report is divided into major several sections outlined below, with additional supporting data and results provided in the appendices:

- Economics of High Renewables
- LNG as the Primary Fuel for Oahu and Maui
- Modifications to Operating Practices
- Investment in Grid Reliability

2.2 Study Approach

The results presented throughout this report were developed using high fidelity models of Hawaii's electric power system. The GE Multi-Area Production Simulation (GE-MAPS) and GE Multi-Area Reliability Simulation (GE-MARS) models were used to accurately simulate key changes on the electric power system. These models are industry-proven analytical tools and the Hawaiian databases used throughout this analysis were developed, vetted and utilized for several technical engineering and planning studies performed for Hawaiian Electric Company, Hawaiian Natural Energy Institute and the Hawaiian state regulator.[1]

The GE-MAPS production cost model simulates the power system operation on an hourly, chronological basis over the course of the year. The model simulates the system operator's (utility) commitment and dispatch decisions necessary to supply the electricity load in a least cost manner, while appropriately reflecting transmission flows across the grid and simultaneously preparing the system for unexpected contingency events and variability. The chronological modeling is crucial to understanding renewable integration because it simulates hourly changes to electrical load and the underlying variability and forecast uncertainty associated with wind and solar resources.

The GE-MARS reliability model also simulates the power system on a chronological basis, but focuses on generation resource adequacy of the system. Based on a full sequential Monte-Carlo simulation, the model evaluates probability of a loss-of-load event (grid blackout) given the generating capacity resources and emergency procedures available to the system operator. In addition, the model was used calculate the capacity value (the ability of a resource to support grid reliability) of variable wind and solar resources. Additional information on GE-MAPS and GE-MARS can be found in the appendix.

[1] Hawaii Solar Integration Study: http://www.nrel.gov/docs/fy13osti/57215.pdf Oahu Wind Integration Study: http://www.hnei.hawaii.edu/sites/dev.hnei.hawaii.edu/files/Oahu_Wind_Integration_Study__Dec%202010.pdf

The study also used a variety of statistical tools that were developed in previous wind and solar integration studies in Hawaii. These tools characterize and quantify the underlying variability in the wind and solar resources to develop operating reserve strategies that ensure enough fast acting conventional thermal and other resources (demand response, energy storage, and ancillary services from wind /solar plants) are available to counteract rapid changes in wind and solar output.

Inputs and assumptions for the models were developed using databases from previous studies conducted by GE, along with inputs and assumptions developed in the recent utility IRP and PSIP filings. Throughout the study, a single study year of 2020 was analyzed, reflecting likely changes to the system within the next several years. Assessing a single study year was determined to be the best way to simulate the power system because it allows direct economic and performance comparisons between scenarios with different renewable energy resources and transmission configurations. Furthermore, it is possible to determine mitigation measures that offer the best economic and performance benefits to the system.

The study simulated 18 scenarios with different renewable resources and over 500 sensitivity cases to asses a range of mitigation measures. In general the focus of these simulations was comparing delivered renewable energy, curtailment, fuel consumption, unit operations, production cost (including fuel, variable operations and maintenance, and start costs), and operating costs (including PPA costs and capital expenditures). The results were also evaluated over several timeframes ranging from a single hour to the entire year, combining both engineering and economic analyses that are critical for power system planning.

2.3 Scenarios & Assumptions

The study was comprised of 18 renewable energy scenarios that evaluated a wide range of wind, utility scale solar PV and distributed rooftop PV additions to both the Maui and Oahu grids. The scenarios were selected to be similar in nature to recently proposed projects and offer a wide spectrum of different resource mixes and levels of available renewable energy. The scenarios were also selected to evaluate whether or not the future RPS targets are achievable utilizing wind and solar resources across Oahu and Maui. It is important to note that the scenarios outlined in this report do not represent technical limits on the amount of renewable integration possible, but were selected to represent appropriate levels of wind and solar capacity required to achieve renewable targets. Table 1 provides the installed renewable generating capacity by island for each scenario.

Half of the 18 scenarios evaluated the Oahu and Maui grids remaining separate, isolated island systems. The other nine scenarios evaluated different interconnections between the islands, either using a “gen-tie” interconnection or a “grid-tie” interconnection of subsea HVDC cables. The gen-tie interconnection included renewable resource off of Oahu connected to the Oahu grid only, with no other resources able to utilize the subsea cable. All power is one-directional originating from the off-island generator and delivered to Oahu. The grid-tie interconnection scenarios were characterized by a subsea cable interconnecting Oahu and Maui and allowing the two island grids to operate as a single power system, with bi-directional power transfer depending on needs and economics. Both of these cable configurations have been proposed for projects on Oahu, Maui and neighboring islands, but this study did not attempt to analyze a particular project or site. Figure 2 provides schematics of the subsea HVDC cable interconnections for each scenario.

Scenario 1 represents the Oahu and Maui grids as they were at the end of 2013, representing the installed thermal capacity and operating practices. This scenario reflects the existing grids as if no additional changes were made. To allow direct comparison to other scenarios, small additions of solar capacity were included to represent near-term utility-scale projects under development and the rapidly growing distributed solar PV segment. Scenario 1 also includes load and fuel projections for 2020 to allow for direct comparison with later scenarios; however the fuel mix in Scenario 1 uses low sulfur fuel oil (LSFO) on the baseload units and does not include the planned fuel switch to diesel. Overall this scenario was selected to allow a reference point simulating what the Oahu and Maui grids would look like if no proposed changes occurred in the near future.

Scenario 2 represents the “grid of the near future.” It builds on Scenario 1 by including system changes that are expected to occur in the near future, (or have already occurred while the study was underway), and therefore were included in the base assumptions for the rest of the analysis. These changes include generator installations and retirements, improvements to baseload unit turndown capability (lower P-min), provision of ancillary services from central wind and solar plants, a fuel switch from LSFO to diesel to comply with environmental standards, and the cycling of Maalaea CC. A more detailed discussion of these changes is found in the appendix. All other scenarios (Scenario 3-18) include these near-term changes. As a result, Scenario 2 serves as the reference scenario in this study analysis when comparing renewable penetration and system economics.

A detailed overview of scenario input data and assumptions, including the system load, fuel price projections, and generator characteristics, are available in the appendix.

Table 1: Scenario Matrix

	Scenario	Oahu RE (MWs)				Maui RE (MWs)				Gen-tie (MWs)	Grid-tie (MWs)
		Wind	Dist. PV	Central PV	Firm	Wind	Dist. PV	Central PV	Firm	Wind	Cable
Isolated Islands	1	100	220	11	74	72	40	-	16	0	0
Isolated Islands	2	100	220	11	74	72	40	-	-	0	0
Isolated Islands	3	100	260	200	74	72	40	--	--	0	0
Isolated Islands	4	200	260	200	74	72	40	--	--	0	0
Isolated Islands	5	300	260	200	74	72	40	--	--	0	0
Isolated Islands	6	100	360	300	74	72	40	--	--	0	0
Isolated Islands	7	200	360	300	74	72	40	--	--	0	0
Isolated Islands	8	200	460	400	74	72	40	--	--	0	0
Isolated Islands	9	200	560	300	74	72	40	--	--	0	0
Interconnected	10	100	260	200	74	72	78	0	--	200	0
Interconnected	11	100	260	200	74	272	78	0	--	0	200
Interconnected	12	100	260	200	74	272	78	100	--	200	200
Interconnected	13	100	360	300	74	72	78	0	--	200	0
Interconnected	14	100	360	300	74	272	78	0	--	0	200
Interconnected	15	100	360	300	74	272	78	100	--	200	200
Interconnected	16	200	460	400	74	72	78	0	--	200	0
Interconnected	17	200	460	400	74	272	78	0	--	0	200
Interconnected	18	200	460	400	74	272	78	100	--	200	200

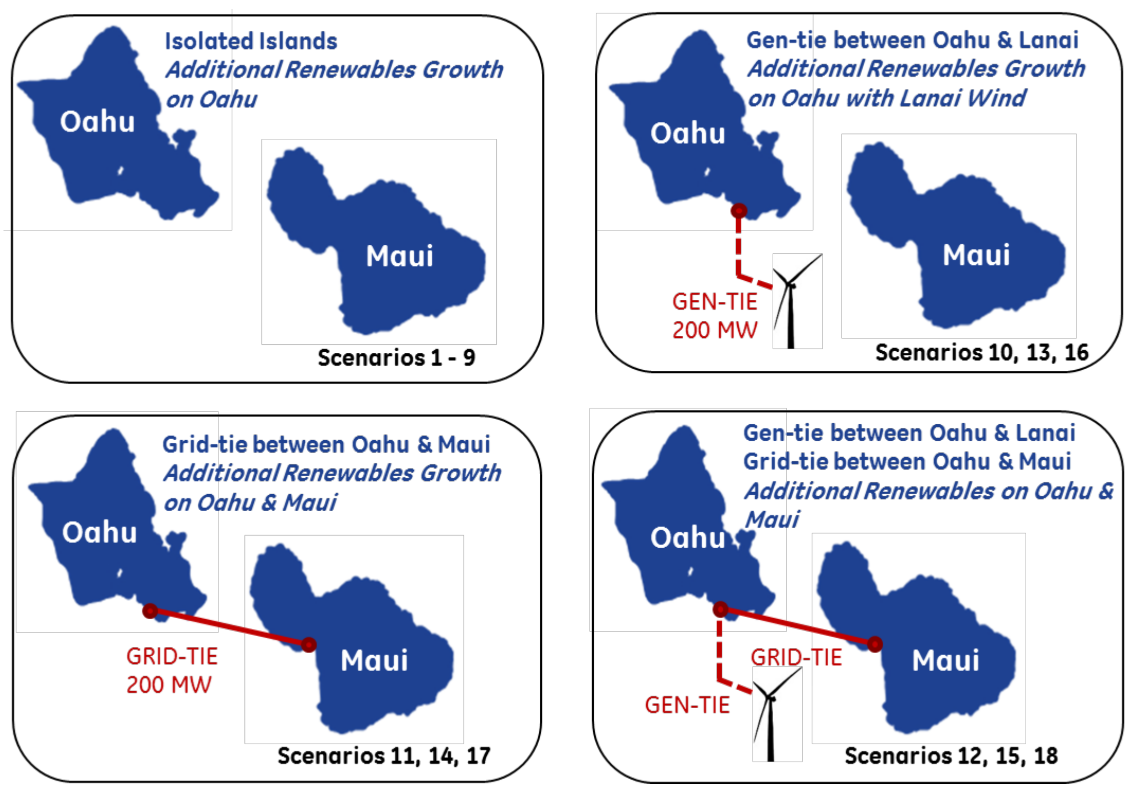


Figure 2: Cable Configurations by Scenario

2.4 Study Scope & Limitations

This study, while extensive and highly technical, does not pretend to be exhaustive, covering all issues related to Hawaii's renewable energy future. In particular the following points highlight the scope and potential limitations of the study:

- This study does not replace existing analysis conducted by the utility, state regulator or other stakeholders in Hawaii. Instead it is intended to supplement those studies with additional technical analysis and findings.
- This study was not designed as an Integrated Resource Plan (IRP) and does not evaluate the optimal resource additions and retirements over several years of study. Instead it selected several scenarios and sensitivities to simulate proposals that have been discussed over time in Hawaii.
- This study only evaluated renewable growth on Oahu and Maui. It does not evaluate renewable growth on the other Hawaiian Islands, which will likely occur and will help support Hawaii's RPS targets. Significant attention was given to Oahu because it is the primary electricity load center for the state, accounting for over 70% of total electricity demand.
- Renewable capacity additions evaluated in this study only consisted of three main technologies; utility-scale wind, utility scale solar and distributed rooftop solar. A wider variety of renewable energy sources are available to Hawaii, but wind and solar are the technologies of choice for the vast majority of proposed projects. Analyzing other potential resources was left to future study work, if and when those assets become more economically feasible.
- This study did not rigorously estimate costs associated with new infrastructure, either for wind and solar plants, subsea cables, or mitigation strategies. Instead it quantified benefits accrued due to implementing these changes and leveraged findings from previous study work to estimate the infrastructure costs. Where costs of implementing new technology or mitigation strategies were not available, this study calculated break-even costs associated with the system changes.
- Although the scenarios outlined in this study are meant to be representative of proposed projects in Hawaii, they are not intended to evaluate any specific projects. Individual project sites were not simulated. Instead, the study used general assumptions and data for candidate technologies.
- This study included a technical evaluation of the economics, operations, and reliability of increased renewable penetration, but it did not include an evaluation of system stability associated with those changes. Instead the reader is directed to previous study work that encompasses that analysis.
- This study analyzed system operation at the bulk-transmission grid level. It did not analyze individual distribution feeders or the circuit loading issues that may result from high levels of distribution-connected rooftop PV systems.

3 ECONOMICS OF HIGH RENEWABLES

3.1 Unprecedented Growth in Renewable Energy

Hawaii is already leading the nation with regards to renewable energy integration. Over the past several years the islands have installed distributed rooftop solar PV at the fastest rate in the United States. As of December 2014, about 12 percent of customers on Oahu and 10 percent of customers in Maui County have installed distributed rooftop PV systems.[2] This unprecedented growth in distributed PV, coupled with large installations of utility-scale wind and solar has already introduced challenges associated with renewable energy integration. In the scenarios evaluated in this study the amounts of wind and solar capacity added to the system was increased dramatically from 443 MW in Scenarios 1 and 2, to 1,610 MW in Scenario 18 (see Figure 3). Firm renewable capacity, including existing waste energy and biomass plants, remained constant at 74 MW in Scenarios 2 through 18. Using the resource availability and load assumptions of the study, the total available energy assumed for each resource, not taking into account potential curtailment, increased from just under 20% of annual energy in Scenarios 1 and 2 to above 50% in Scenario 18. The renewable energy penetration numbers are based on the energy supplied to meet the load requirement:

Equation 1: $$Renewable\ energy\ penetration\ (\%) = \frac{Annual\ renewable\ energy\ production}{Annual\ load\ energy\ consumption}$$

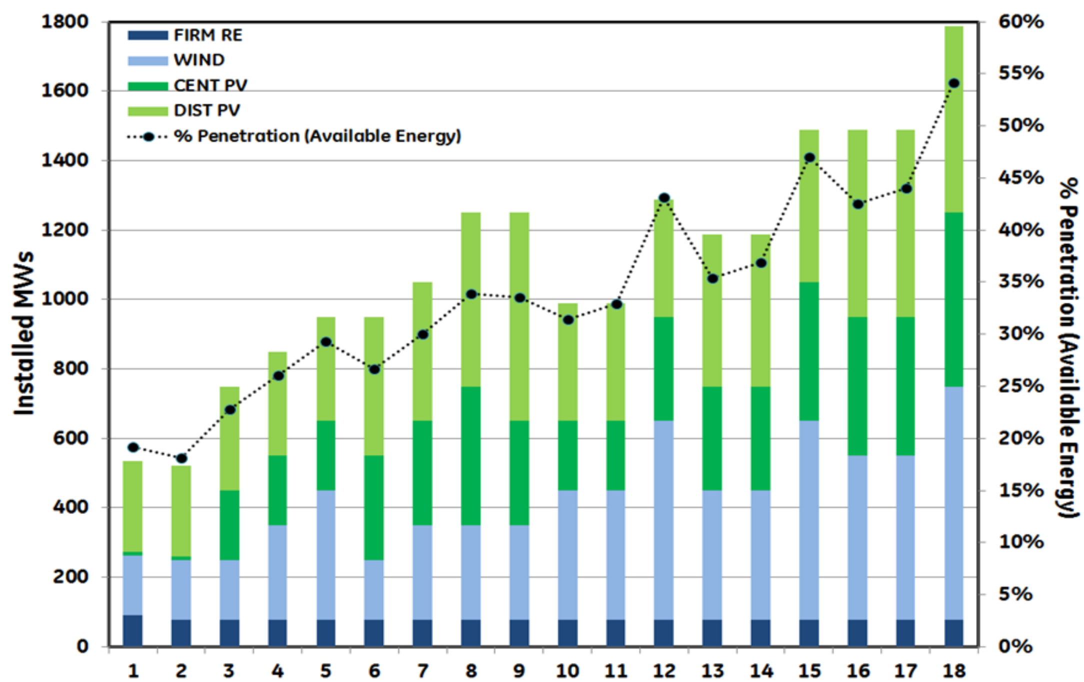


Figure 3: Renewable Capacity and Available Energy by Scenario

2 http://www.hawaiianelectric.com/heco/_hidden_Hidden/CorpComm/Hawaiian-Electric-Companies-propose-plan-to-sustainably-increase-rooftop-solar

This study evaluated many different combinations of wind, central PV and distributed PV resources located on Oahu and Maui. Some scenarios also considered a 200 MW off-island wind resource. Scenarios 1-9 evaluated isolated islands and demonstrated that renewable energy penetration could exceed 33% of annual load energy requirements of the Oahu and Maui grids (see Figure 3). Scenarios 10-18, which assumed combinations of “grid-tie” or “gen-tie” HVDC interconnections, demonstrated that renewable energy penetration could exceed 50% of annual load energy.

It should be noted that the scenarios evaluated in this study do not represent limits to renewable growth or annual energy penetration for either Oahu or Maui, but were selected to demonstrate options available to the Oahu and Maui grids in order to achieve RPS targets. When selecting the study scenarios, it was recognized that the extent of wind and solar development on Oahu will be subject to the quality of the potential wind/solar resources (capacity factor) and the availability of land. Therefore, some of the study scenarios include wind and solar resources off of the island of Oahu. However, these off-island resources were not required to achieve 2030 RPS objectives. Rather, they were simply considered as possible alternatives to scenarios with all on-island resources.

This dramatic increase in renewable energy capacity will require significant changes to how the existing power grid is operated. The data in Figure 3 represent available energy only. However, integrating variable resources will sometimes lead to curtailment of some wind and solar energy. Curtailment occurs when the system is unable to accept the power produced by a wind or solar plant due to transmission or operational constraints on the system. When this occurs, the wind and solar plants are required to reduce output and the excess energy is “spilled.” There is a significant incentive to minimize curtailment. The energy source for wind and solar is essentially free and clean. When it is curtailed, the unused (spilled) energy must be replaced by energy from thermal plants, resulting in increased operating costs and increased emissions.

On Oahu and Maui, curtailment generally occurs due to operational constraints rather than transmission constraints. In general, these operational constraints are a result of minimum stable operating levels (P-min) of the thermal units online. Even when reduced from the existing P-min levels, the committed baseload units can cause curtailment if they cannot be cycled off. Reasons for this include fixed operating schedules, required commitment to provide up-reserves or down-reserves, or unexpected fluctuations and forecast error of wind and solar energy. Figure 4 provides scatter plots of delivered renewable energy penetration (% of annual load) and wind and solar curtailment (% of available) for each of the scenarios evaluated in the study. On the left-hand chart, the line represents what the renewable energy penetration would be in the absence of curtailment. While on the right hand side chart, the line represents the increase in curtailment as more and more renewable energy is added to the island.

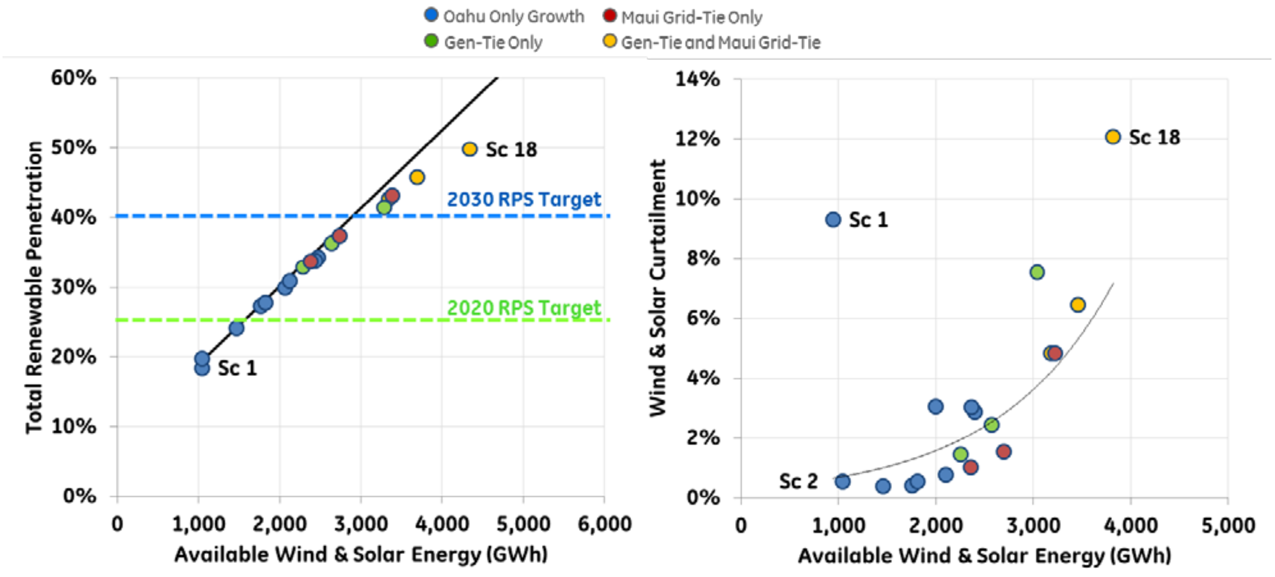


Figure 4: Total Renewable Penetration and Curtailment by Scenario

Although curtailment is sometimes unavoidable to maintain a stable and reliable electricity system, it can be dramatically reduced and minimized, resulting in significant variable cost savings to the grid. If mitigation measures and changes are put in place to current operating strategies, much of the available energy can be accommodated by the Oahu and Maui grids. The curtailment in Scenario 1, approximately 10% of available wind and solar energy, quantifies the expected curtailment if such mitigation measures are not adopted by the system operator.

The decrease in wind and solar curtailment between Scenario 1 and Scenario 2 represent changes to the grid that are expected to occur in the near future to help increase delivered renewable energy (as outlined above). However, the results continue to indicate decreasing marginal returns for each GWh of available wind and solar. As new resources are added to the system, curtailment increases and the added value from the wind and solar resource begins to decline. Although total system curtailment is within reasonable levels, even in the latest scenarios, the additional mitigation measures and changes to operating practices outlined throughout this report outline some of the ways that curtailment can be reduced further. However, it is not always necessary to alleviate all curtailment, but should be attempted when it is economic to do so.

The modifications highlighted above were assumed to continue in all remaining scenarios and include reduced minimum stable levels on existing baseload units, the retirement of underutilized thermal units and replacement with quick-start capability generators, and the partial provision of down-reserves from wind and central PV plants. Although these changes successfully decreased wind and solar curtailment in early scenarios, even with these mitigations in place, curtailment begins to increase as renewable capacity increases to higher levels. Additional mitigations to reduce curtailment and system costs were also evaluated in this study. The results of that analysis are provided in Section 5.

3.2 System Operation with High Renewable Penetration

Given the rapid growth of wind and solar penetration, grid operators in Hawaii are required to address integration challenges sooner than other US grids. In fact, Oahu and Maui system operations have already been dramatically altered in the past few years to support renewable energy. Unlike other US grids that have large geographic footprints and transmission interconnections to neighboring grids, the integration challenges for Hawaii are compounded by the fact that the power grids are small isolated islands. As a result, Hawaii is becoming a test bed for renewable energy integration. The lessons learned here will be transferred to other North American grids as they begin reaching similar levels of renewable penetration.

For example, the islands are already experiencing dramatic shifts to the system's net-load curve (defined throughout the report as total load minus wind and solar generation). Sometimes referred to as the "duck-curve," this change occurs when the daily load pattern begins to dip during midday hours. These hours of the day, historically referred to as "on-peak" hours, used to be characterized as high load hours requiring additional thermal cycling and peaking generators online. However, with the growth of solar PV, the net load during midday hours is often lower than during early-morning or late-evening hours. This leads to fundamental changes to the commitment and dispatch of the conventional thermal generators on the system. Thermal generators are needed for less overall energy, but more part-load, quick-start and ramping capability. As the renewable penetration increases, the net load curve will become even more pronounced, with net load being lower during midday hours than during nighttime hours.

Figure 5 shows the net load curve for Oahu with 200 MW of wind capacity and 231 MW of solar PV (mostly distributed PV) capacity for an average day in March. Just below, Figure 6 highlights the same average day in March, but with an additional 100 MW of wind capacity and an additional 629 MW of solar capacity. Under these conditions, the early morning ramp up to follow the daily load pattern is immediately followed by an even larger ramp down as solar generation across the system increases. As the solar generation begins to decline throughout the afternoon, the late afternoon and early evening hours of the day experience a dramatic ramp up of the net load energy requirement. This three-hour ramp up is over double the magnitude compared to early morning ramp ups historically experienced by the system operator.

Although the ramping capability on the system is adequate to cover these ramps, it will require accurate wind and solar forecasting and appropriate preparation by the system operator. These new trends in daily net load will significantly change operation patterns of the baseload thermal generators. In an instance in Figure 7, the net load curve becomes negative. This implies that without curtailment, there is excess generation on the system. If this particular scenario was heavily distributed solar PV dominated, curtailment would not be an option and most of the thermal units would need to be de-committed and then brought online quickly to follow the net load pattern. This creates challenges on the operations (commitment and dispatch procedures) as well as maintaining grid stability.

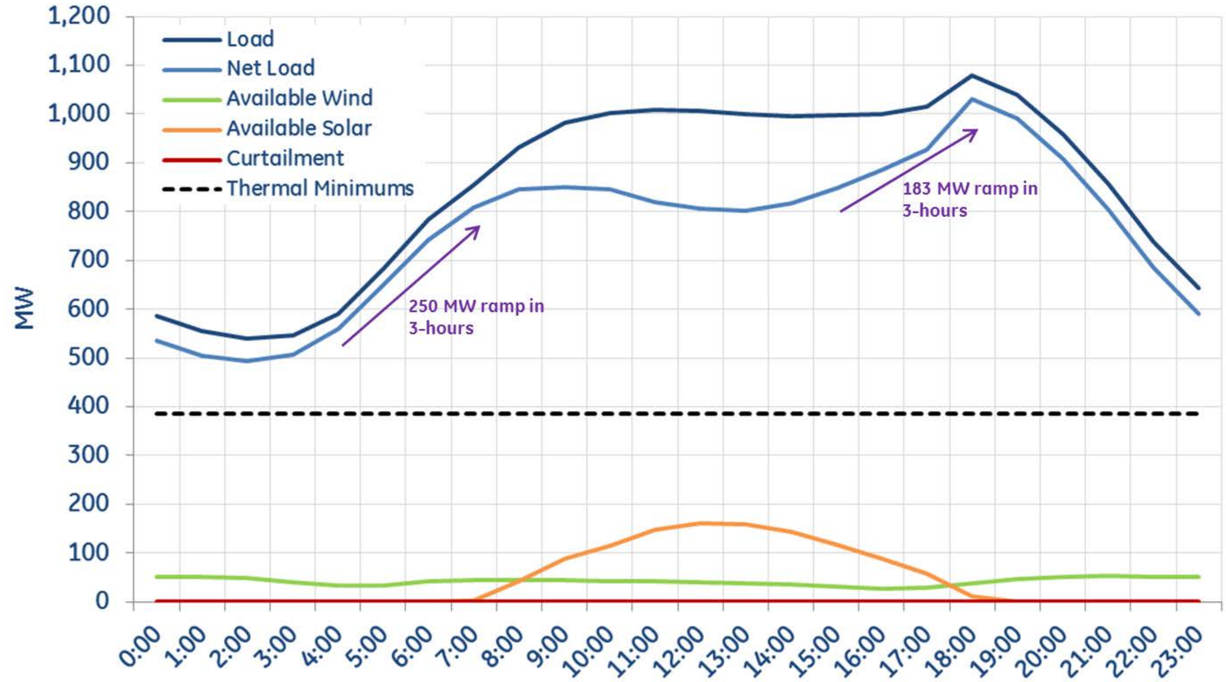


Figure 5: Oahu Net Load Curve, Scenario 2, "Low Renewables"

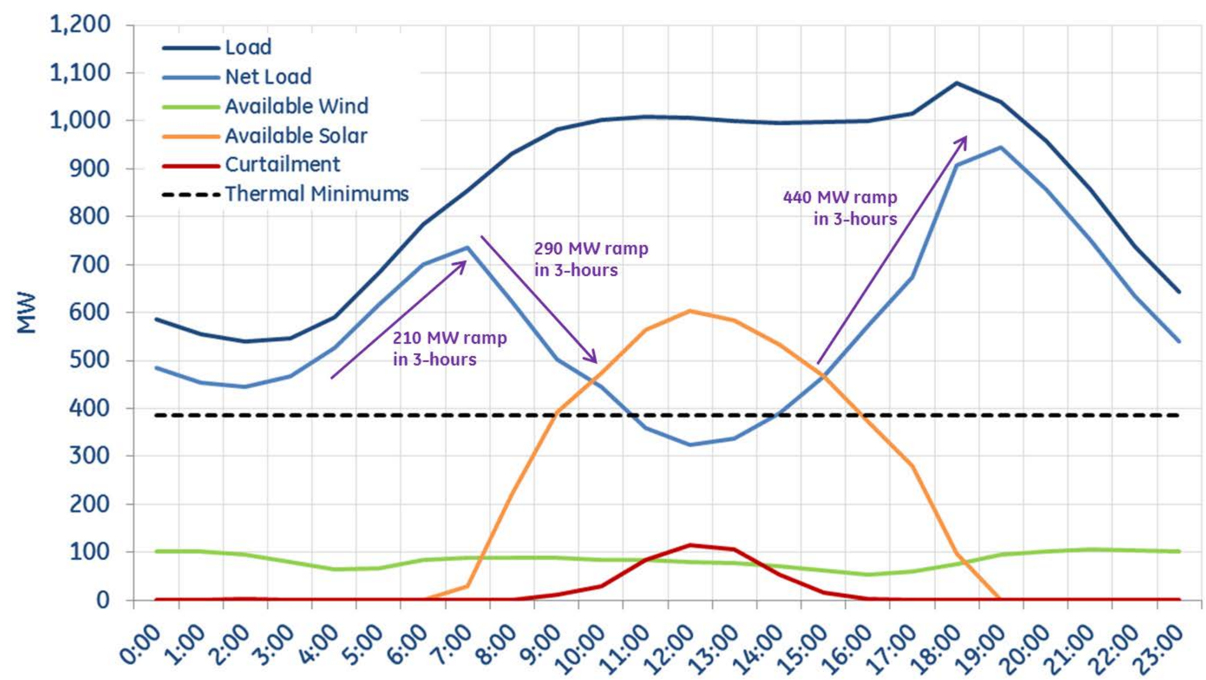


Figure 6: Oahu Net Load Curve, Scenario 8, "High Renewables"

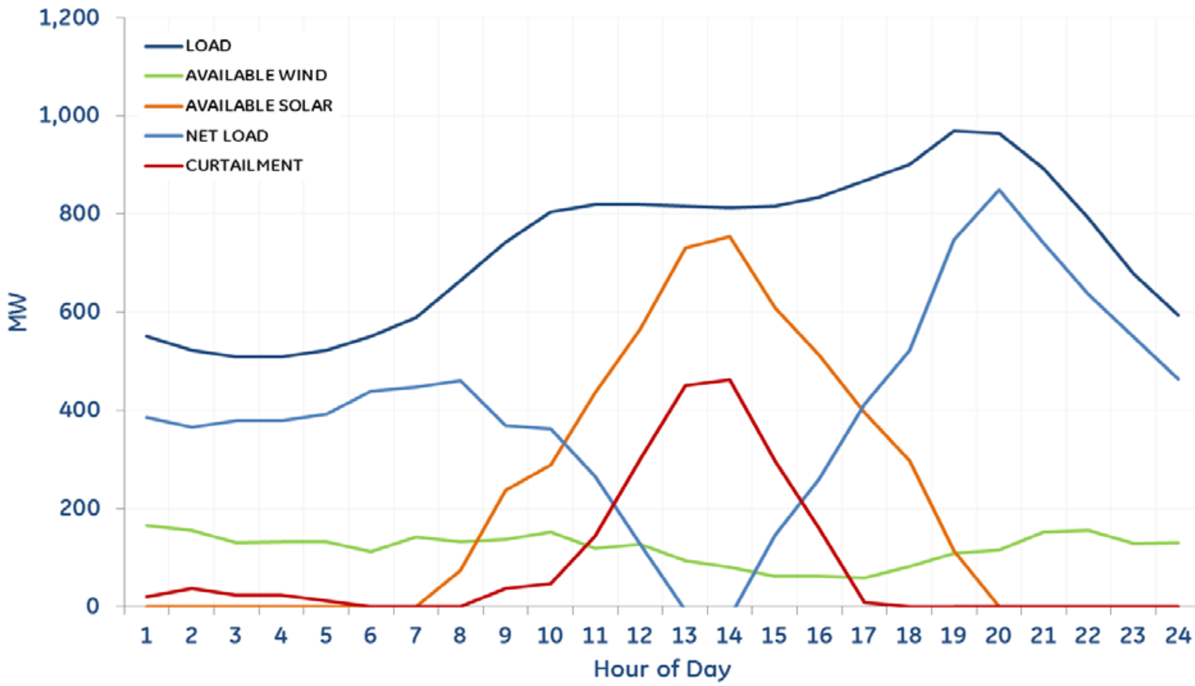


Figure 7: Oahu Net Load Curve, Scenario 8, "Negative Net Load"

Another way to visualize the change to system operation with increasing levels of wind and solar generation is showing a weekly chronological dispatch chart, segmenting the generation from each type of resource on the system. Figure 8 shows the chronological weekly dispatch for Oahu for a typical week in June in Scenario 2, which includes 100 MW of wind capacity and 231 MW of solar capacity on Oahu. As the chart indicates, the majority of the wind and solar penetration occurs during mid-day hours reducing the maximum load from about 1,200 MW to a net load[3] in the range of 1,000 MW. The thermal units follow a fairly predictable pattern;

- AES, the most economic unit on the system, runs at full load for the entire week.
- Kalaeloa CC operates in 1x1 CC configuration overnight with one gas turbine online providing waste heat to power the steam turbine. The unit then switches to 2x1 CC operations during daily on-peak hours.
- Other baseload units, including Kahe 1-6 and Waiau 7&8, ramp up to full load during the day and turn down to lower loading overnight. There is no need to cycle units off because they are needed again for the next day's load.
- Cycling units are utilized during the day, and turned off during overnight hours.

[3] Net Load = total load minus wind and solar generation. In the plots, the net load is served by the firm RE units (gray), baseload units (blue), cycling units (purple) and peaking units (red). The maximum value of the net load is about 1000 MW on all days of the week.

- Peaking units are used sparingly during on-peak hours and are displaced most by the wind and solar. They continue to be important assets during evening hours when load remains high, but the solar resource is no longer available.
- All available wind and solar energy is used to serve load and there is no curtailment during any hour of the week.

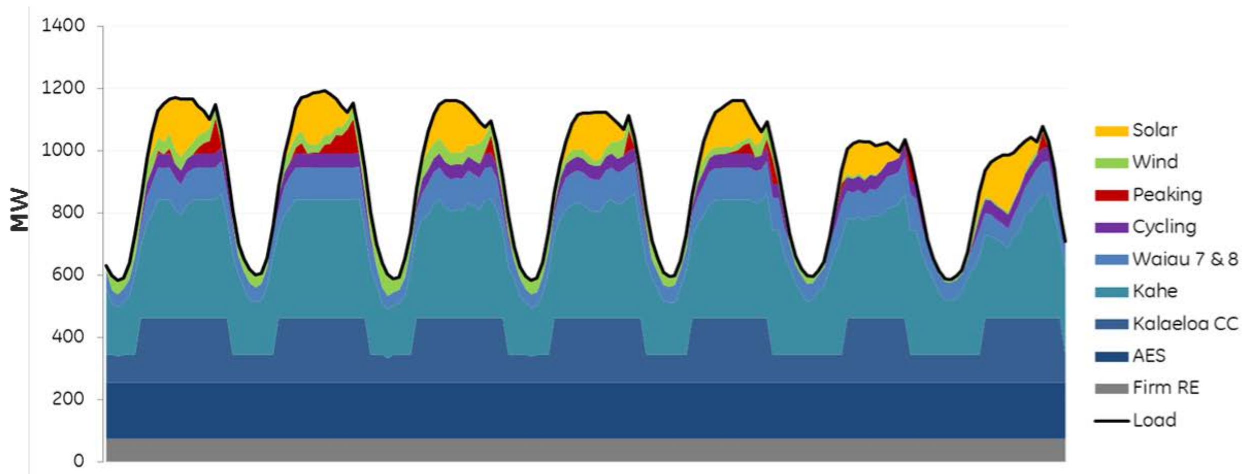


Figure 8: Oahu Chronological Weekly Dispatch, Scenario 2

Figure 9 shows the same week of system operation for Scenario 16, with 300 MW additional wind capacity and 667 MW additional solar added to the system. Under the higher renewable penetration levels, the chronological weekly commitment and dispatch patterns are significantly from historical operations. With increased levels of wind and solar penetration it is expected that:

- The baseload units, including AES, Kahe, Waiau 7&8, and Kalaeloa CC no longer follow a typical daily profile of turning down to minimum at low-load overnight hours and ramping up to full load during on peak hours. Instead the units are ramping up and down several times a day to follow the system net load.
- Cycling and peaking units, which are the most expensive to operate, decrease commitment and dispatch, even during times where the ramp requirement is highest. The majority of this cycling duty is shifted to the historically baseload units.
- Cycling and peaking units are still required for short periods during evening peak load hours when the solar resource is no longer available and system load is highest.
- Midday hours often have greater than 50% wind and solar penetration. However, this can vary from day to day and even from hour to hour.
- The majority of curtailment takes place during midday hours when the solar output is highest, but some wind curtailment also occurs during overnight hours due to low load and fixed operating schedules of the thermal units.

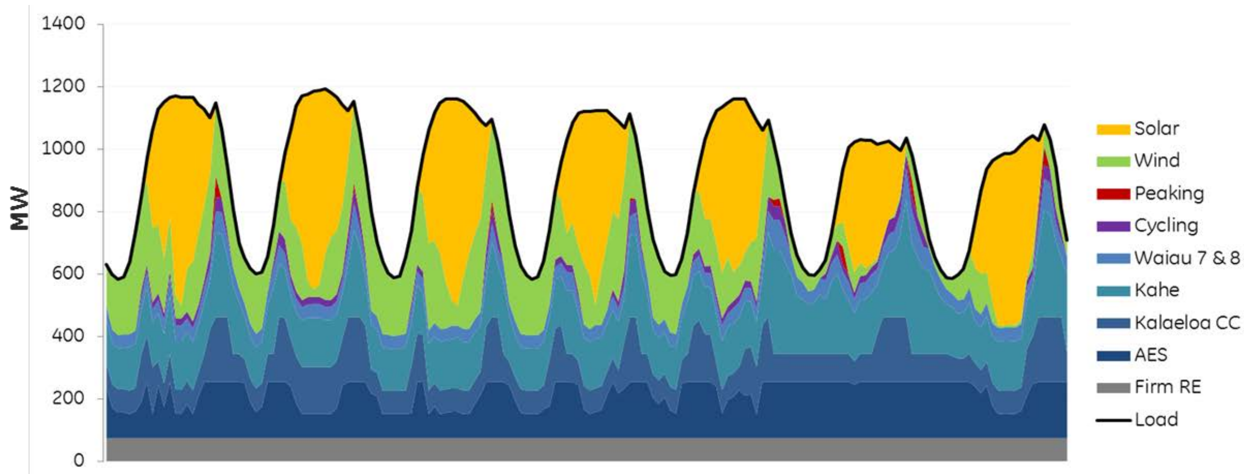


Figure 9: Oahu Chronological Weekly Dispatch, Scenario 16

3.3 Interconnecting the Islands

Interconnecting the Oahu and Maui grids with a HVDC cable (grid-tie) or interconnecting Oahu to an off-island wind plant (gen-tie) offers several potential benefits. The ties enable access to additional sites that have higher quality wind resources (higher capacity factors) than on Oahu. Suitable land for new wind plants on Oahu is already scarce. Furthermore, interconnecting the Oahu and Maui grids would increase operational flexibility, reduce reserve requirements, and improve grid reliability.

For the purposes of this study, the cable size was assumed to be 200 MW, but sensitivities were conducted so that the modeling could estimate potential maximum power flows across the cable to help evaluate options for different size cables. For the gen-tie configuration, the cable flows are dependent on the size of the remotely located plant, in this case a 200 MW wind plant. As a result, cable flows will never exceed 200 MW. From a modeling perspective therefore, the gen-tie configuration is no different than siting the wind plant on Oahu once losses are taken into account.

For the grid-tie configuration, the cable flow is dependent on excess renewable power on Maui as well as any additional thermal power that may be more economic than the committed thermal units on Oahu. With a 200 MW cable size for the grid-tie interconnection the cable was at maximum utilization about 10% of hours in the scenarios evaluated. When the cable was fully utilized, excess renewable energy was curtailed on Maui. Although the cable flow was generally in the Maui to Oahu direction, during some hours the flow reversed direction. The reverse flow was limited to 30 MW to avoid a large contingency event on Maui due to the loss of generation being imported via the HVDC cable. The 30 MW limit is consistent with existing loss-of-generation contingency levels on the Maui system. The reverse flow predominately occurred during midday hours when solar output on Oahu was highest and the thermal units were backed down to minimum loads. As solar penetration increases on Oahu, power flow from Maui to Oahu declines, resulting in more hours of reverse flow to Maui. This is an important consideration when evaluating proposals for cable size, as it likely that Oahu will experience significant solar additions over the life of the HVDC cable. Figure 10 shows the annual duration curves of the cable flow in each of the interconnected scenarios Table 2 provides the summary statistics.

Table 2: Maui-Oahu Interconnection Summary Statistics

	SCEN 11	SCEN 12	SCEN 14	SCEN 15	SCEN 17	SCEN 18
Total Flow (GWh)	900	858	855	776	735	636
Maui to Oahu Flow (GWh)	886	834	835	743	694	576
Oahu to Maui Flow (GWh)	14	24	20	33	41	61
Utilization (%)	51%	49%	49%	44%	42%	36%
Maui to Oahu Flow (% of Hrs)	90%	86%	86%	81%	78%	69%
Oahu to Maui Flow (% of Hrs)	10%	14%	14%	19%	22%	31%
Hours Limited (to Oahu)	821	1,110	576	750	299	469
Hours Limited (to Maui)	156	428	265	594	742	1,104

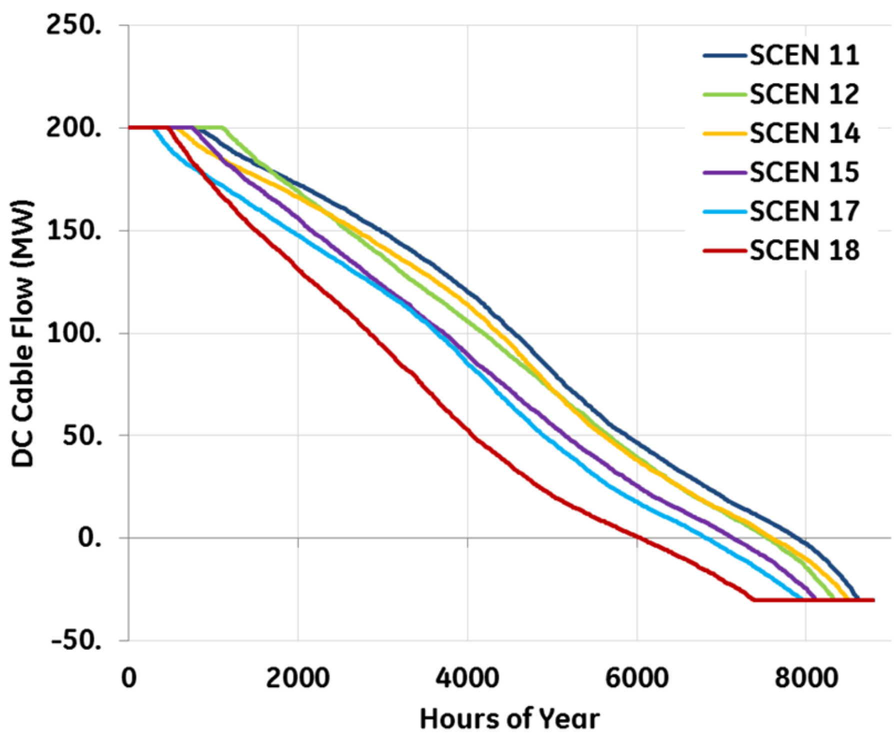


Figure 10: Duration Curves of Maui to Oahu HVDC Cable Flows

The grid-tie configuration has additional benefits other than increased renewable penetration. Although not the primary focus of this study, there are benefits associated with operating the two island systems as a unified grid. Operational benefits include the sharing of operating reserve required for wind and solar variability and some potential for economic recommitment and dispatch of thermal units. These benefits would occur regardless of whether or not additional renewables were added to the system, but the benefits increase as the total amounts of renewables increase. For more information on the operational benefits, refer to the findings of the Oahu-Maui interconnection study. A second operational benefit of a unified grid is increased reliability (resource adequacy) and lower risk of not meeting the load. The reliability benefits of the interconnection were evaluated in this study and the findings are presented in Section 6.

3.4 Economics of High Renewable Penetration

The wind and solar additions evaluated in this study require large capital investments, both to add new infrastructure and to make modifications to existing grid infrastructure and operating practices. To evaluate the economics of each scenario, the modeling used throughout this study included production cost analysis coupled with additional financial modeling techniques. The production cost analysis, which simulates the chronological hourly generation dispatch in the GE MAPS model, includes all of the variable operating cost factors of a power system. These include fuel costs, variable operations and maintenance cost (VO&M), and unit startup/shutdown costs (Equation 2). The system production cost is the critical economic metric when evaluating the impact of increased renewable penetration on power system operations, including changes to commitment and dispatch decisions, increased cycling, and increased part-load heat rates.

Equation 2: $$Production\ Cost = Fuel\ Cost + VO\&M\ Cost + Startup/Shutdown\ \ Cost$$

Other costs that are not included in traditional production cost analysis must also be considered when evaluating future renewable energy scenarios. Costs associated with power-purchase agreements (PPAs) for existing renewable resources and the capital costs associated with new infrastructure (renewable plants or DC cables) and equipment and modifications required for grid upgrades must also be included in the evaluation. The annual savings associated with reduced production costs are partially offset by the additional PPA costs and capital investments required to increase renewable penetration on the system. This relationship is illustrated in Figure 11. In order to include these costs in the evaluation, the study measured total annual operating costs for each scenario and sensitivity case as defined in Equation 3.

Equation 3: $$Annual\ Operating\ Cost = Production\ Cost + PPA\ Cost + New\ Capex\ Cost$$

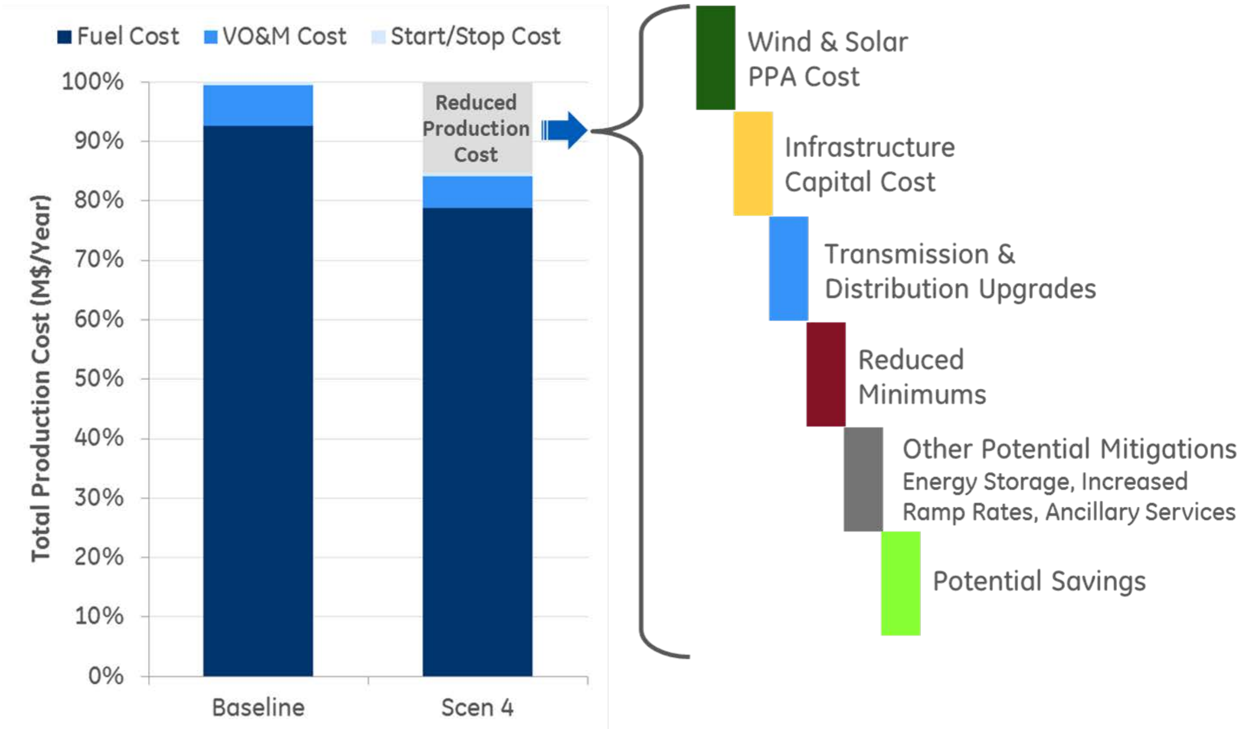


Figure 11: Components of Total Operating Cost

Figure 12 shows the annual production costs for the study scenaios. The declining trend for right to left shows that production costs decrease significantly as renewable energy is added to the system. This is because the wind and solar are assumed to be zero variable cost resources. In other words, the fuel for wind and solar plants is free and therefore the plants do not require incremental costs to produce a MW of power. As a result, the additional wind and solar generation added to each scenario displaces more expensive thermal plants, which leads to reduction in annual production cost. As discussed in Section 3.2, the increased renewable penetration can increase the cycling (startup/shutdown) costs and lead to thermal units operating at part-load levels, which is more expensive per MW of production when operating at a less efficient power point. These cost increases however are smaller than the significant fuel savings associated with the displaced energy. As a result total annual production cost is reduced by 95 M$ (-7.2%) to 496 M$ (-37.4%) depending on the scenario evaluated, relative to Scenario 2 (the reference scenario).

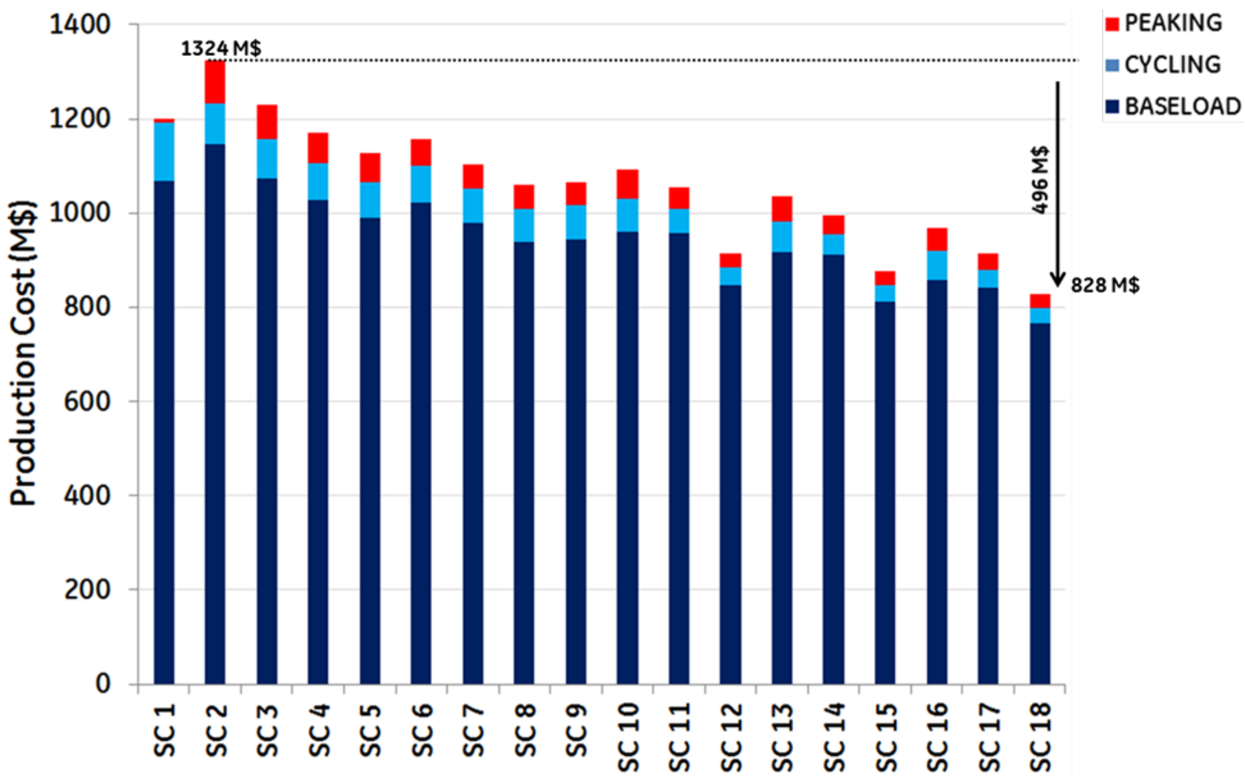


Figure 12: Annual Production Cost (M$) by Scenario

The PPA costs associated with existing renewable energy resources (wind, solar, waste, and biomass) are readily available from recent PUC filings. For this study, the delivered renewable energy from each plant is multiplied by the PPA price. For some plants, the PPA price varies by the amount of energy delivered over the year via a tiered structure and others vary by time of day. Because the existing wind and solar plants are not curtailed significantly in each scenario (the curtailment occurs mostly on the new resources) the PPA costs in each scenario are essentially constant at 200 M$ per year.

The capital expenditures required for new infrastructure and grid upgrades have the most uncertainty. This portion of the analysis includes the capital costs for new wind and central solar plants, HVDC cables for island interconnections, lower turndown levels and fuel switching on the existing thermal units, and new installations of proposed internal combustion engines on Oahu and Maui. Whenever possible the study used recent estimates for new infrastructure and capital expenditures that have been outlined in PUC filings, approved HECO budgets, or recent reports. In some cases capital cost estimates were not readily available for proposed Hawaii projects. In those cases, literature reviews were conducted to develop cost estimates based on recent industry experience. The capital cost estimates for new infrastructure and grid upgrades are provided in Table 3 below. Note that the capital costs associated with distributed rooftop PV are not included in the analysis because the decision is made by the individual ratepayer and is not an expenditure of the system operator.

Table 3: Capital Cost Assumptions for New Infrastructure and Grid Upgrades

Infrastructure / Grid Improvement	Cost	Units
Central Wind Plant	2,500	$/kw
Central Solar Plant	3,000	$/kw
Schoffield Barracks 50 MW Combustion Engines	180	M$
Maui 34 MW Combustion Engines	122	M$
HVDC Interconnection (Grid-Tie) 200 MW	606	M$
HVDC Interconnection (Gen-Tie) 200 MW	520	M$
Lower Turndown Capability on Baseload Units	70	M$
Fuel Switch to Diesel	51	M$

The simulations were conducted for a single study year and as a result it was necessary to convert the capital costs into an annualized expenditure. To do this a fixed charge rate (FCR), also known as a capital recovery factor, was used. A FCR is based on assumptions regarding the weighted average cost of capital (WACC) and the economic life of the project (Equation 4). However, rather than estimating a weighted average cost of capital or economic life for each project, a range of potential FCR values from 10% to 14% was used to represent a reasonable range of estimates for this type of analysis. It was also assumed that the annualized value includes any fixed operations and maintenance (FO&M) associated with the new resources and grid upgrades. This approach was used due to the inherent uncertainty and generic level of detail required for any system planning study where specific infrastructure details are unknown. As individual projects are proposed in detail, a more rigorous methodology can be utilized.

Equation 4: $$Fixed\ Charge\ Rate = \frac{i*(1+i)^t}{(1+i)^t-1}$$

where:

$$i = weighted\ average\ cost\ of\ capital\ (WACC) or\ discount\ rate$$
$$t = economic\ life\ of\ the\ plant$$

The total annualized capital costs are reported in Figure 13 assuming a 10% fixed charge rate. The costs fall into three categories; grid upgrades, new renewable plants, and HVDC cables. The total cost for the grid upgrades is 43 M$. This cost includes upgrades to accommodate additional renewable energy (P-min reductions), new installations of internal combustion engines added for reliability and flexibility, and the EPA mandated fuel switch to diesel on the existing thermal units. The cost of grid upgrades is held constant across the scenarios and does not include any associated costs required to upgrade distribution feeders to accommodate additional rooftop solar. The majority of the additional capital expenditures are for additional wind and solar plants added to the system across the scenarios. For the isolated island scenarios (without HVDC cables), total annual capital expenditures ranges between 46 M$ in Scenario 2, to 187 M$ in Scenario 8. The last component of the annual capital expenditures is for the HVDC interconnection cables evaluated in Scenarios 10-18. The range of capital expenditures is dependent on the type of interconnection (grid-tie or gen-tie) and the number of cables (single or both gen and grid-ties). The interconnections bring the total annual capital expenditures between 204 M$ in Scenario 10 to 430 M$ in Scenario 18.

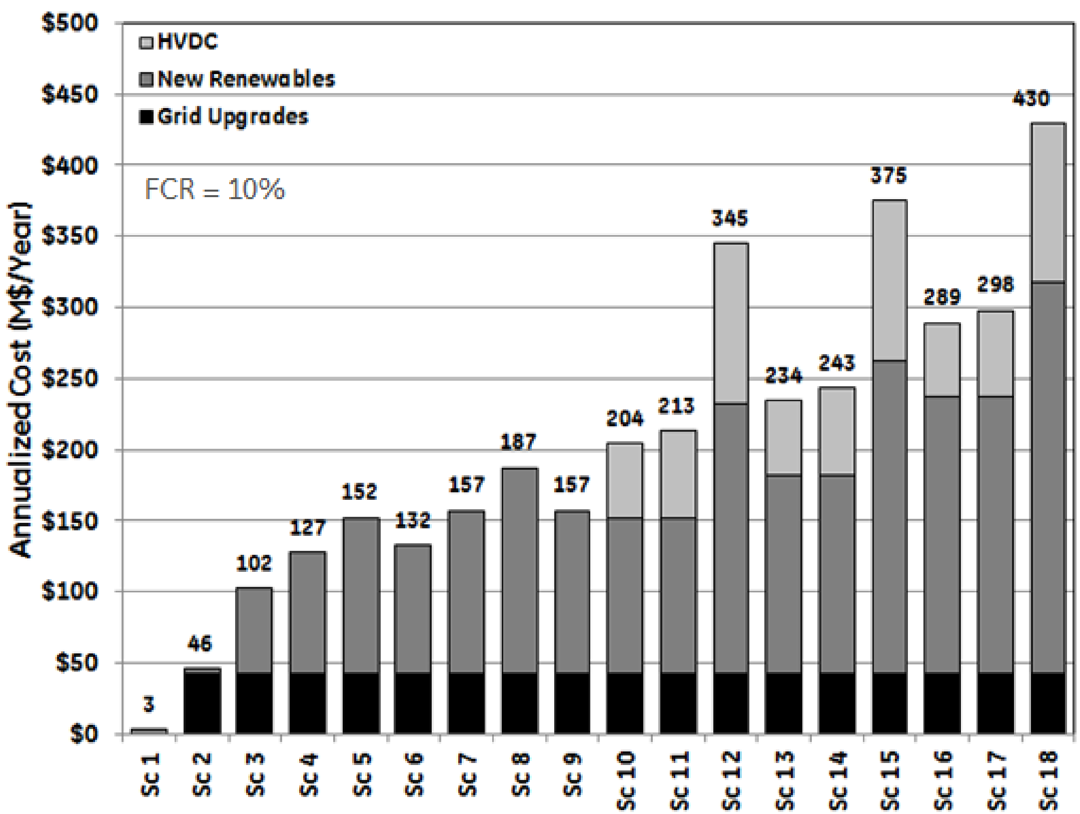


Figure 13: Annual Capital Expenditures (M$) by Scenario

When the production cost, PPA cost and annualized capex cost are added together, the resulting total operating cost provides a holistic representation of the system economics (see Figure 14). The values in this chart still do not include the complete costs of operating the system because it does not include fixed costs, FO&M, or payments necessary to serve debt on previous investments. However, because these items are fixed and the same for all scenarios, they do not change based on system operation or future investments and therefore can be excluded from the analysis. With all three components added together it can be concluded that under the scenarios analyzed and using the study's assumptions, increased renewable penetration can reduce the system's total operating costs while achieving the state's Renewable Portfolio Standards goals. This is true even when accounting for capital expenditures associated with new infrastructure and grid upgrades.

With these changes to the system, system's reliance on fossil fuel imports and electricity price volatility associated with the underlying volatility of the global oil markets will reduce. The total annual operating cost shifts from a variable cost structure (where the majority of costs depend on fuel consumption) to a cost structure more heavily weighted to fixed annual payments associated with the capital expenditures of wind and solar plants.

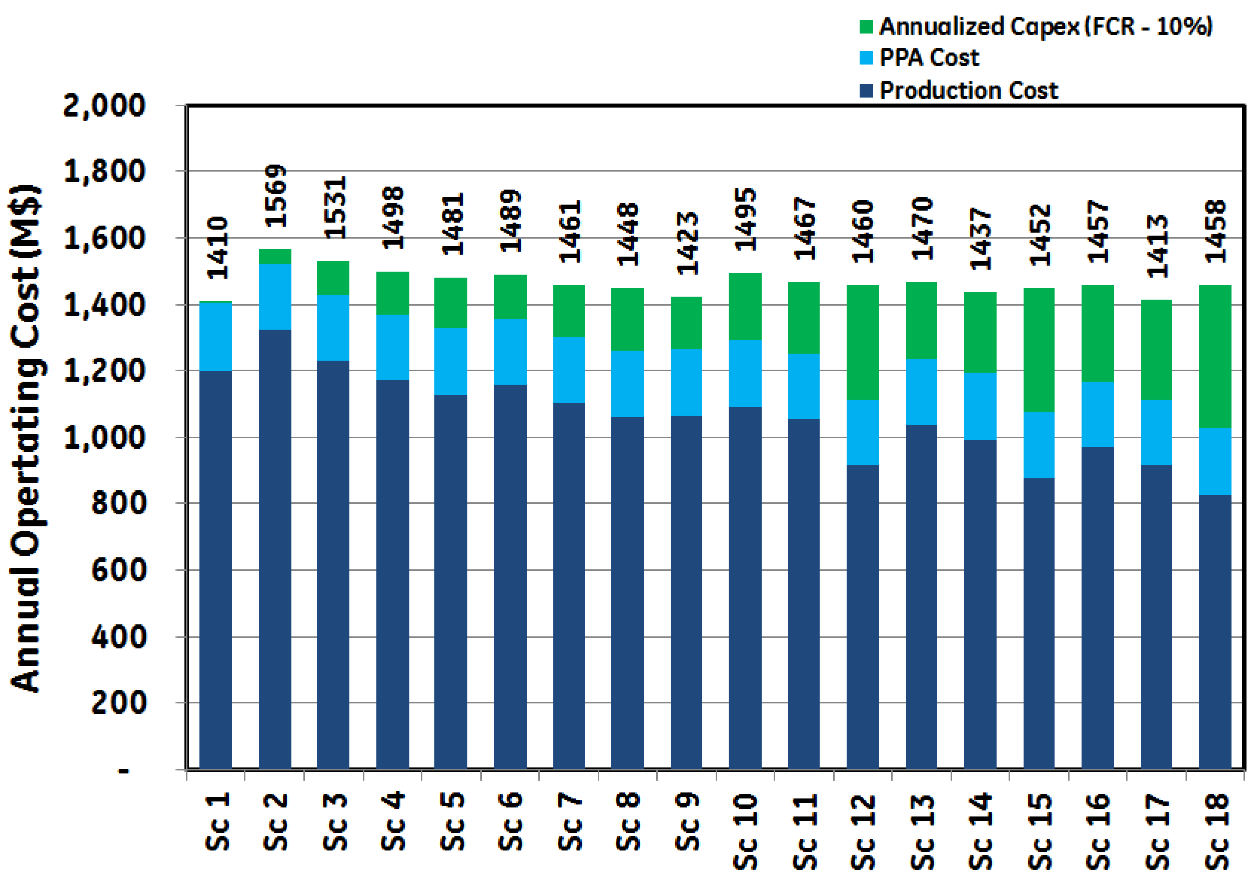


Figure 14: Total Annual Operating Cost (M$) by Scenario

For the isolated islands scenarios, total annual operating costs were reduced by 38 M$ to 146 M$ depending on the scenario evaluated. For the interconnected scenarios, annual savings ranged between 74 M$ and156 M$. It is important to note that scenarios with both the gen-tie and grid-tie interconnections resulted in higher total annual operating costs (compared to scenarios with a single cable) due to the additional capital expenditure for the additional cable. However, renewable penetration was higher in those scenarios and the total annual operating costs were still lower than the reference scenario (Scenario 2).

Given the large amount of capital investments required for the new infrastructure and grid upgrades, the total annual operating costs are highly dependent on the cost of capital and the FCR assumption. A higher cost of capital will increase the total annual operating cost and reduce the economic benefits associated with renewable energy. Using a 14% FCR assumption total operating cost by 18 M$ (1.1%) in Scenario 2 to 172 M$ (11.8%) in Scenario 18 (see Figure 15). The higher cost of capital assumption narrowed the margin of system savings and caused the total annual operating cost to exceed the reference scenario in two scenarios (Scenarios 12 and 18, with two HVDC cables). The annual savings were most impacted in scenarios where the second HVDC cable was added to the system.

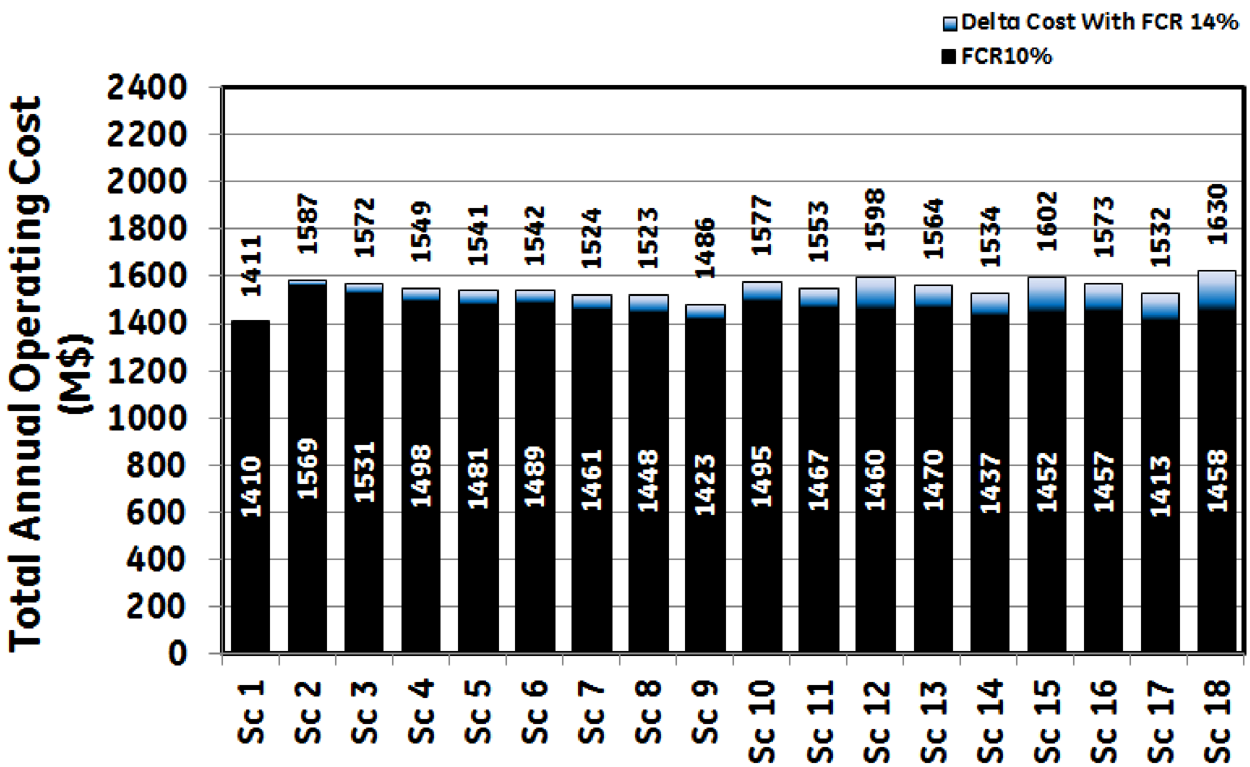


Figure 15: Total Annual Operating Cost (M$) with Range of FCR by Scenario

Another way to evaluate the economic performance of the system is by measuring the total cost to serve the utility load. Because much of the new renewable resources are distributed rooftop solar, their generation appears to the system as a reduction in system load and a corresponding reduction in revenue for the system operator. Utility load is defined as the total system load minus the distributed PV output. This is the load that needs to be served by the thermal generation fleet and centralized utility-scale renewable plants. When the total annual operating costs are divided by the utility load, the resulting $/MWh metric is a proxy for the wholesale price of electricity on the system. The range of total cost to serve utility load is shown in Figure 16 with assumptions of 10% and 14% FCR. In the reference scenario (Scenario 2) the cost to serve utility load is $184/MWh and is reduced by up to $10/MWh (-5%) when assuming a 10% FCR. Under the 14% FCR assumption, total cost to serve utility electricity load increases in eight of the highest capital cost scenarios. Note that savings from increasing renewables on the islands is highly dependent on the cost of capital as well as cost of the underlying baseload fuel mix.

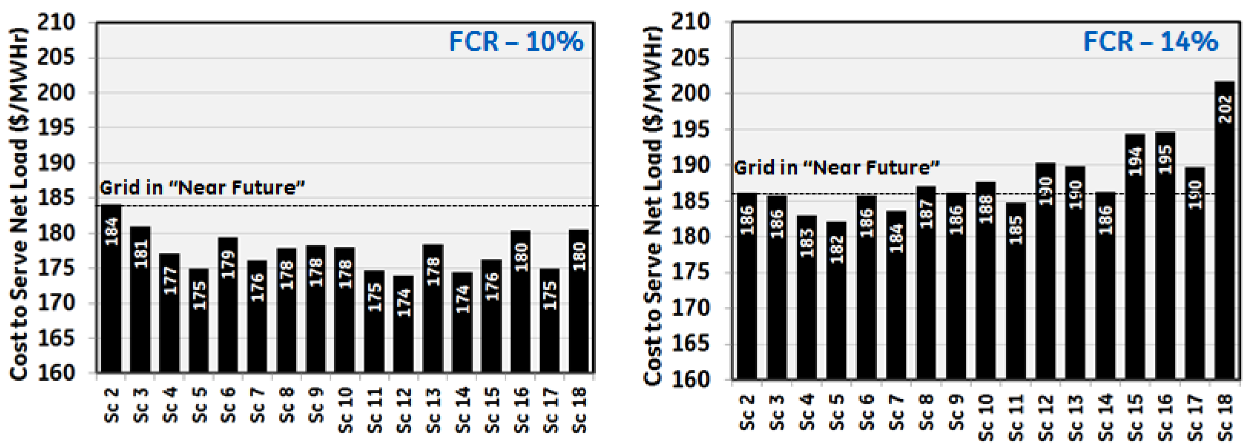


Figure 16: Total Cost to Serve Utility Load ($/MWh) by Scenario

3.5 Resource Diversity is Important

Distributed solar PV is growing at fast pace in Hawaii. It is projected to increase to almost 500 MW on Oahu by 2020-21 time frame, as per HECO's PSIP. This roughly translates to 0.5 kW of distributed solar PV for every kW of electrical load. This fast growth in distributed solar PV will improve the contribution of green energy on Oahu, however distributed solar PV by itself will not be enough to meet the RPS goals. Figure 17 shows the contribution of an installed capacity of 500 MW of distributed PV, central PV, and wind towards the RPS goals. Distributed solar PV has the lowest capacity factor, and therefore its contribution is limited in supporting the RPS goals. On the other hand, each MW of wind is twice effective in contributing towards increasing renewable energy penetration. In addition, a number of grid stability and reliability factors become important as the penetration of distributed PV increases, requiring the PV inverters to provide similar grid friendly services that are available from utility scale renewable energy plants, such as:

- Curtailment during periods of excess energy on the grid
- Fast frequency responsive service under contingency conditions
- Voltage and reactive power support capabilities
- Voltage and frequency ride through capabilities

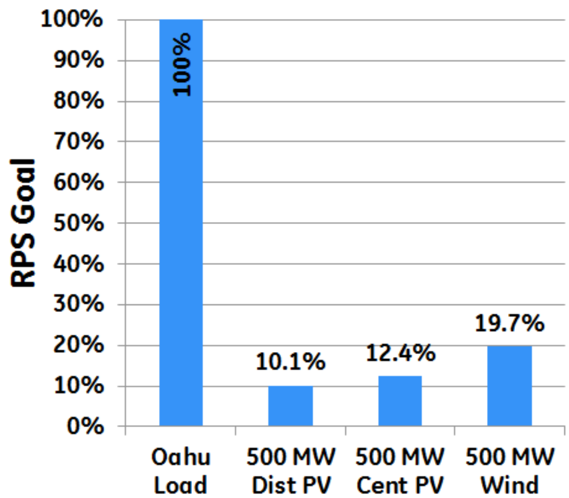


Figure 17: Contribution by different resources towards the RPS goals

A balanced resource mix is needed to reach the RPS goals in a favorable manner. Figure 18 shows two scenarios: a balanced resource mix scenario (scenario 5) and a high solar growth scenario (scenario 6). The performance metrics shown in Figure 19 favor the balanced resource mix scenario over the high solar growth scenario in every respect:

- Higher renewable energy delivered to the system
- Lower operational and production cost
- Reduced need for ancillary services, such as operating reserves, due to resource diversity
- Higher percentage of curtailable renewables provide flexibility to system operation

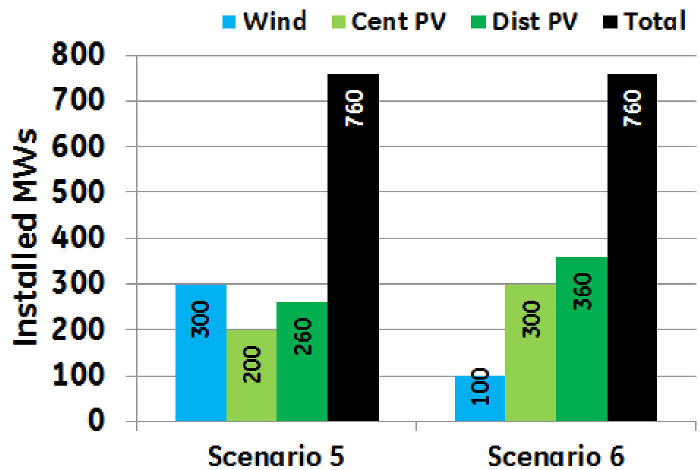


Figure 18: Balanced Resource Mix (Scen 5) vs High Solar Growth (Scen 6)

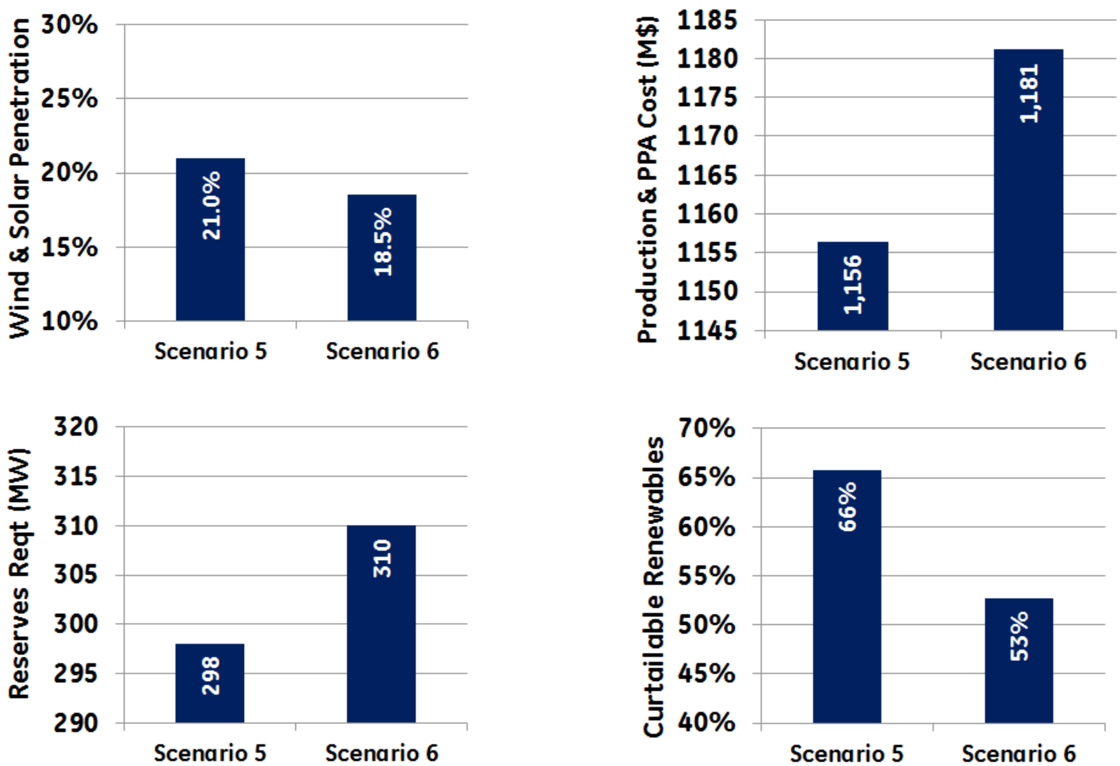


Figure 19: Performance of Balanced Resource Mix (Scen 5) vs High Solar Growth (Scen 6)

4 LNG AS THE PRIMARY FUEL FOR OAHU AND MAUI

Natural gas can be an attractive approach for lowering the cost of electricity as the islands transition to increased levels of renewable energy. The economic benefits, however, depend primarily on the contract price to deliver liquefied natural gas (LNG) to the Hawaiian Islands. This depends not only on the raw fuel price and the supporting supply chain but also on the quantity required, which will likely decrease in the more distant future as the islands increase their utilization of renewable energy. This section presents key findings on the economics of LNG as the primary fuel for baseload thermal power plants on Oahu and Maui.

4.1 Delivered LNG Price Must be Competitive

In order for LNG to be considered as the preferred fuel for thermal power plants, the delivered price of LNG must not only be lower than the cost of fuel oil and diesel, but should also be competitive enough to recover the investments for building new pipelines, upgrades to units, shipping costs from Oahu to Maui, and other related infrastructure. In other words, the savings associated with reduced production cost must be larger than the required capital investments before it can translate to lower cost of electricity (Figure 20).

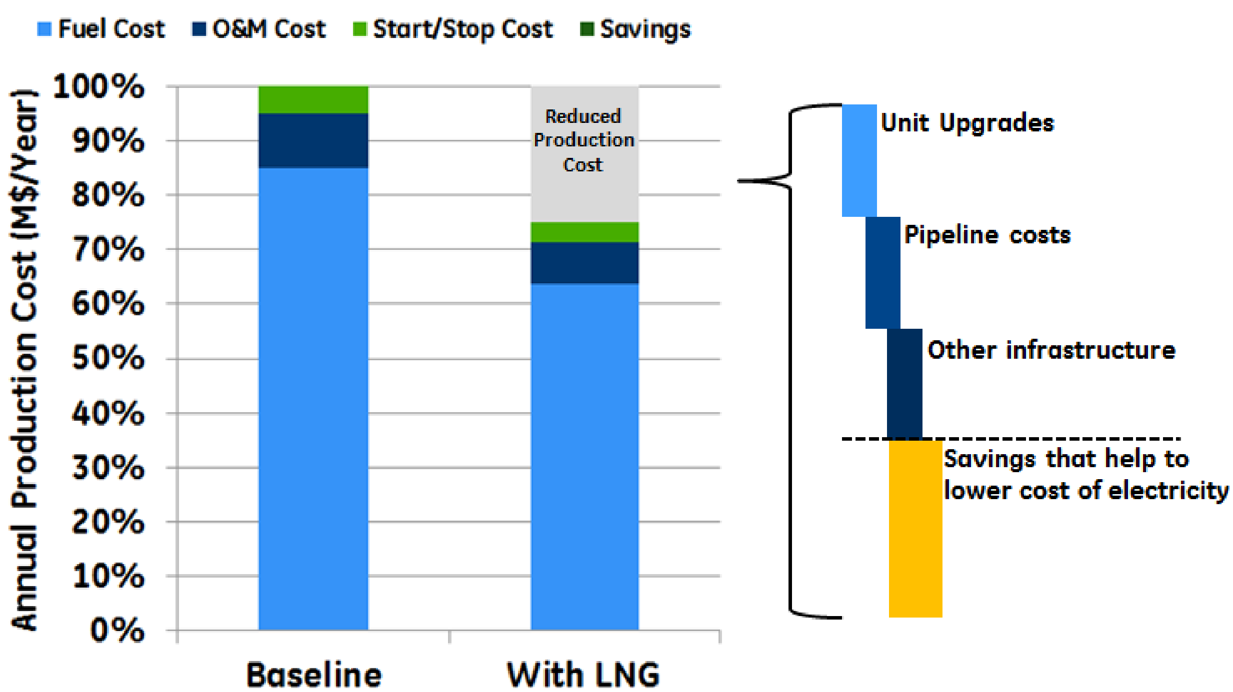


Figure 20: Production Cost Savings from LNG Must Recover Capital Expenditures

Given that Oahu is the major load center in Hawaii, the bulk of production cost savings can be captured with LNG fuel switch on Oahu alone. Additional savings, though incremental, can be achieved by also using LNG on Maui. Based on recent utility filings to PUC and studies conducted by other consultants, the price range of LNG delivered to Hawaii can be economical to replace the existing baseload generator fuels. In Figure 21, the ""LNG Base Price" is lower than LSFO, diesel and bio-diesel. The "High LNG Price" is higher than the cost of LSFO on Oahu, making it an unviable option for Hawaii. For the remainder of this section, the analysis is based on the "LNG Base Price" assumption only.

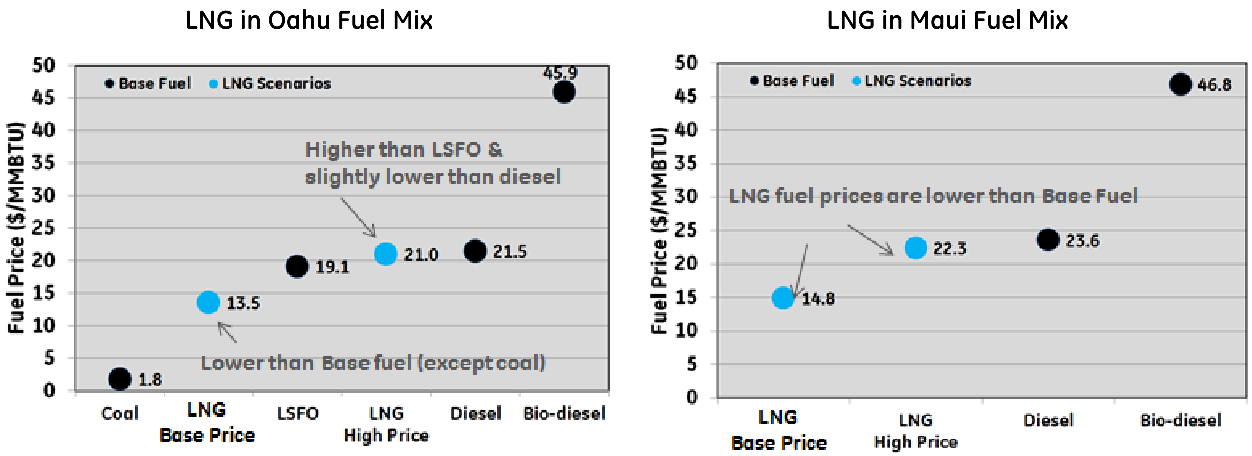


Figure 21: Estimated Prices of LNG Relative to Other Fuels on Hawaii (2013 $)

4.2 What's the Appetite for Natural Gas in the Power Sector?

The consumption of natural gas depends on the number of generators that will switch to natural gas as well as on the energy generated from these units. Per initial utility filings, approximately 1.1 GW of generation capacity on Oahu and 106 MW of capacity on Maui are prospective candidates for being switched to burn natural gas as the primary fuel. Figure 22 shows how output of the Oahu thermal generators decreases with increasing levels of wind and solar energy, from 16% (in Scenario 2) to 50% (in Scenario 18). This trend directly impacts the potential future consumption of natural gas on the islands, which decreases by over 35%(includes, start-up fuel costs and heat rate efficiency impacts) in Scenario 18. This would likely impact the terms and pricing structure for contracts to deliver natural gas to Hawaii.

Oahu Units	Capacity MWs	Generation (% of Load) Sc. 2	Generation (% of Load) Sc. 18
Kalaeloa	208	17%	12%
Kahe 1	82	4%	2%
Kahe 2	82	5%	3%
Kahe 3	86	4%	2%
Kahe 4	85	6%	3%
Kahe 5	134	7%	3%
Kahe 6	134	8%	6%
Waiau 5	55	1%	1%
Waiau 6	54	1%	0%
Waiau 7	83	4%	3%
Waiau 8	86	3%	2%
	1,090	62%	37%

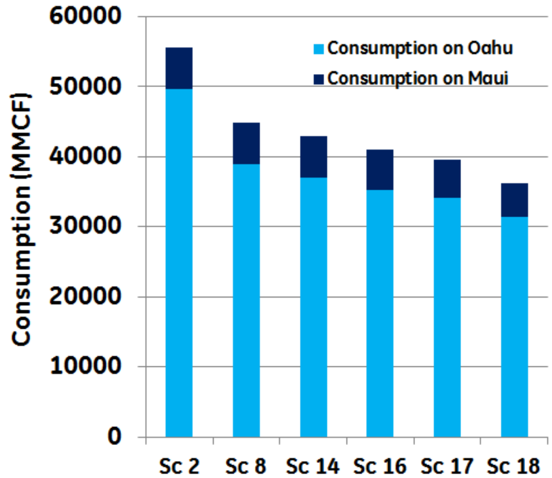


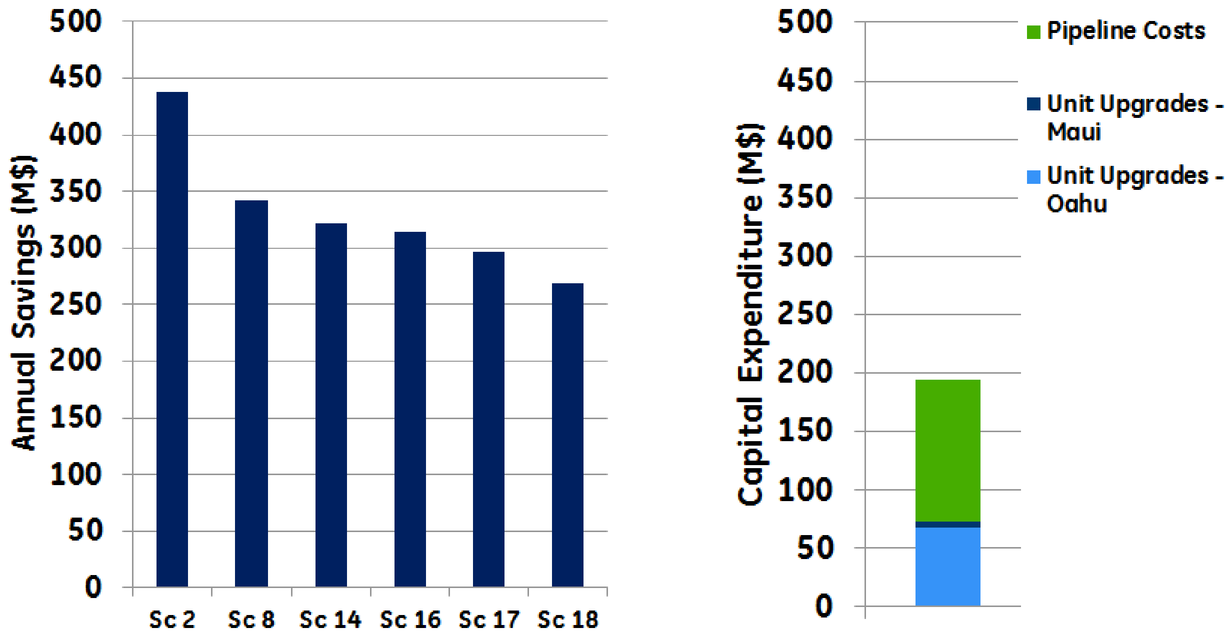
Figure 22: Changes in Natural Gas Consumption as Renewable Penetration Increases

4.3 Lower Cost of Electricity with LNG

LNG can potentially reduce the cost of electricity by replacing more expensive diesel and fuel oil. However, in order to realize these savings, additional capital investments are needed to develop gas pipelines and to convert boilers and plant controls to use natural gas. Conversion to LNG will reduce the cost of electricity only if the savings in fuel costs exceed the required capital investments.

The total required expenditure for infrastructure upgrades on Oahu and Maui is estimated to be 200 M$ (2013 $)[4]. The annual savings in Scenarios 2 through 18 exceed this total capital expenditure, with the LNG Base Price assumption (Figure 23). This implies that the return on investment is less than a year, thus making LNG a very attractive option for lowering the cost of electricity. Figure 24 shows that the cost of electricity can be decreased by up to 23% by switching the baseload fuel to natural gas on Oahu in the high renewable energy scenarios. The cost of electricity can be further decreased (up to 27%) by switching the baseload fuel to natural gas on both Oahu and Maui. This is based on a fixed charge rate of 10% for the cost of capital. At higher capital cost rates, the cost of electricity will be higher and the savings would decrease, especially in the scenarios that require more capital investments. Please note that the calculations are based on the fuel price forecasts from the 2013 HECO IRP. Under possible conditions of lower fuel prices, the cost of electricity will be lower than the numbers presented here.

[4] HECO Integrated Resource Plan 2013



LNG as the primary fuel on Oahu and Maui; Price of gas is 13.5$/MMBTU on Oahu and 14.8 $/MMBTU on Maui

Figure 23: Annual Savings in Production Cost and Total Capital Expenditure for LNG

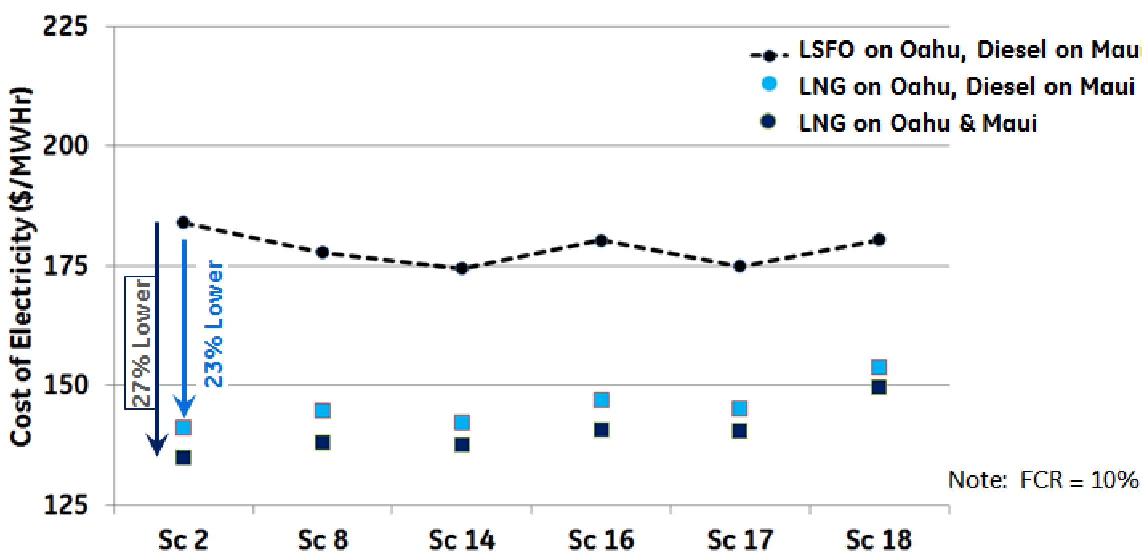


Figure 24: Cost of Electricity with LNG as the Primary Fuel

5 MODIFICATIONS TO OPERATING PRACTICES

As the generation resource mix changes from fossil-based "firm energy supply" to renewable-based "intermittent and variable energy supply," it becomes imperative to make changes to the grid operation and infrastructure that can help to accommodate these resources while maintaining a reliable power system. In order to achieve the RPS mandates, the island grids will require new operational protocols and infrastructure upgrades, without which it will become increasingly difficult to accommodate higher levels of wind and solar energy. The island power grids, in general, demand increased flexibility to counteract the increased intermittency and variability. This can be provided through appropriate changes in the commitment and dispatch procedures, ability of the online generation to cycle up and down or on and off daily, new controls that can enable the thermal generators to be turned down lower, and additional ancillary services. Without implementing these changes to improve system operational flexibility, the islands grids will not be able to accommodate more renewables (Figure 25).

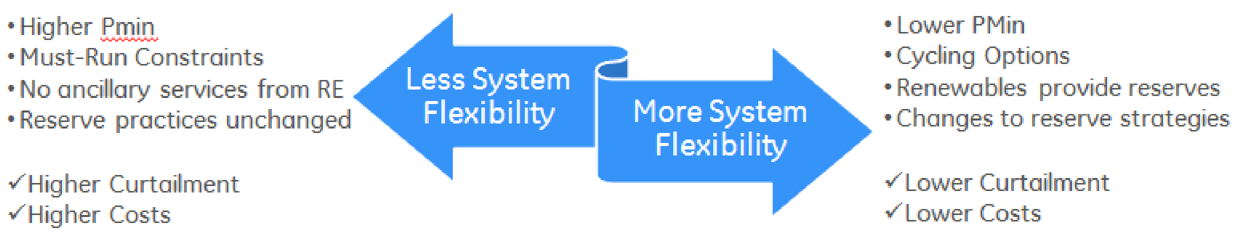


Figure 25: Grid Requires Operational Flexibility to Accommodate Renewables

5.1 Modifications Required in the "Near-Term"

The Oahu and Maui grids should begin to implement two critical modifications in order to prepare for accommodating higher renewable energy penetration. These modifications will help to provide the largest benefits in terms of lowering the operating cost, while increasing the potential to absorb new renewable energy. These modifications are included as baseline assumptions in each of the scenarios analysis presented in Section 3. This section quantifies the value of these modifications by re-simulating selected scenarios without these modifications and capturing the increase in production cost and renewable energy curtailment.

1. Lower turndown capability of thermal units (Reduced Pmin): This modification will enable the thermal units to reduce their output to lower levels when renewable energy is available. This not only helps in increasing the "available room" on the grid to accommodate available renewable energy but it also increases the availability of the important up-reserve ancillary service. When thermal units can be turned down lower, additional up-reserves become available. This further helps to reduce the commitment of additional units that would otherwise be required to satisfy the up-reserves requirement, thereby reducing overall system operating costs. In the 2013

IRP filing, HECO has proposed to implement lower turndown capability on all the baseload units on Oahu and Maui.

2. Down-Reserves from wind and solar plants: Down-reserve ancillary service is the counterpart of up-reserves. During disturbances that result in excess generation (e.g. transmission fault resulting in loss of substation and/or the load connected to its feeders), this ancillary service enables the system to reduce generation quickly. Traditionally, this requirement is imposed on the thermal generators. Units are operated above their minimum power limit so that they can be dispatched down in response to a loss-of-load event. As the renewable penetration on the islands increases, thermal units will be operating at these above-minimum power levels for many more hours of the year, not being able to be turned down to their technical operating minimum power levels. This in turn reduces the grid's ability to absorb more renewables, resulting in curtailment. Utility scale wind and solar plants have the capability to provide down-reserves by temporarily reducing their output, and could therefore provide some of that ancillary service in place of the thermal units. Since this ancillary service is used only during contingency events, the impact on renewable energy curtailment is insignificant.

Figure 26 illustrates the benefits of these two modifications, separately as well as when implemented together for Scenario 16. Renewable energy delivered can be increased by up to 13% and the annual operating cost can be decreased by up to 100 M$. The annual savings can also be interpreted as the break-even capital expenditure for implementing these modifications. If the annual capital expenditure is less than the reduction in annual operating costs, then investment in the modifications is economically attractive.

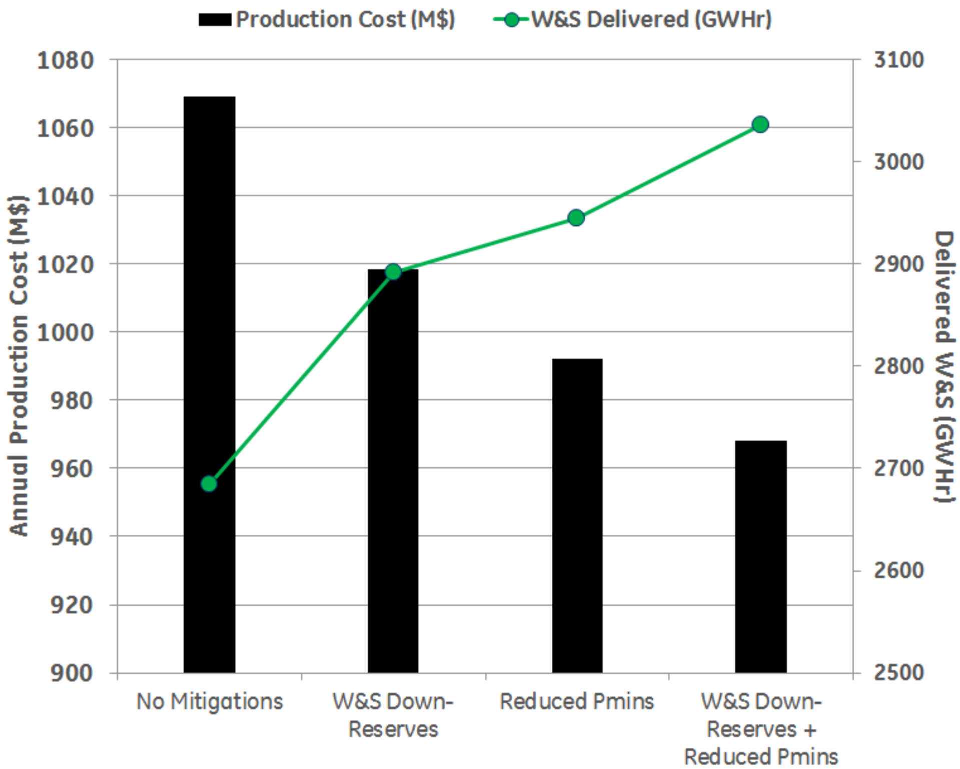
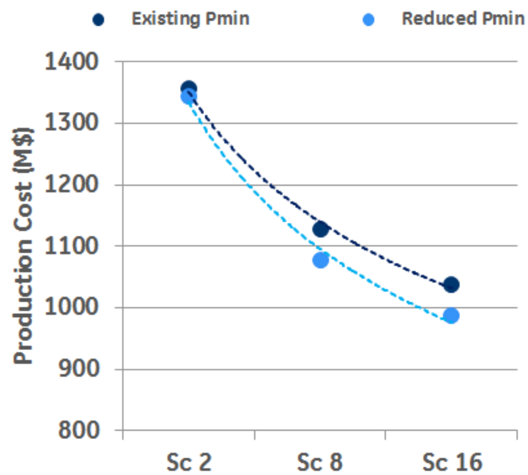


Figure 26: Impacts of Near-Term Modifications on System Performance (Scenario 16)

5.1.1 Lower Turndown Capability of Thermal Units

Lowering the turndown capability of the baseload units will relieve 94 MW of capacity on Oahu and 17 MW on Maui (Figure 27). This means that for every hour of the year, the island grids will be able to accommodate up to 111 MW of additional renewable energy. The benefits from this modification will be realized as more renewable resources are installed on the island grids. The annual production cost is not noticeably different with this modification under present-day renewable generation on the islands (Scenario 2). But with higher penetration levels that are likely to occur in the future (e.g., Scenarios 8 and 16), the benefits from annual production cost savings would likely outweigh the capital expenditure for implementing this modification. It is therefore recommended that HECO and MECO implement lower turndown capability on the thermal units, as outlined in the 2013 IRP filings, which will prepare the power grids for future high renewable scenarios.

	Existing P-Min	Reduced P-Min
Kahe 1	32.5	18.0
Kahe 2	32.7	18.1
Kahe 3	32.3	17.7
Kahe 4	32.3	17.7
Kahe 5	50.7	25.0
Waiau 7	23.0	18.1
Waiau 8	23.0	18.1
Maalaea CC	35.0	18.0



Note: Scenarios assume base assumptions of down-res from renewables

Figure 27: Value of Lower Turndown Capability of Thermal Units

5.1.2 Down-Reserves from Utility Scale Wind and Solar Plants

Wind and solar plants can contribute towards this ancillary service requirement on the grid with implementation of a frequency-droop based governor control system and connection to the grid's automatic generation control (AGC). Wind and solar plants would perform this service by reducing their output, and therefore could only provide down-reserves when they are producing energy; similar to how and when a thermal unit contributes towards the down-reserves requirement. Equation 5 shows how the down-reserves would be allocated between the utility scale renewables and the thermal generators.

Equation 5: $\boldsymbol{Ratio\ of\ Down\ Reserves\ from\ W\&S} = \dfrac{\boldsymbol{Wind\ \&\ Solar\ Capacity}}{\boldsymbol{Wind\ \&\ Solar\ Capacity + Thermal\ Capacity}}$

The benefits from this modification increase as the renewable penetration increases: increase in utility scale renewables means more down-reserves can be provided from wind and solar plants, and therefore the thermal units can be operated at lower dispatch levels. As a result additional capacity can be made available on the grid to accommodate more renewables and in the process, the operating costs can be lowered further (Figure 28). The ability to provide this ancillary service is important when considering investments in distributed vs central PV. Similar to the previous modification, it is recommended that HECO and MECO make the necessary changes to the interconnection mandates for existing and new utility scale renewable energy generators to be able to contribute towards down-reserves on the grid.

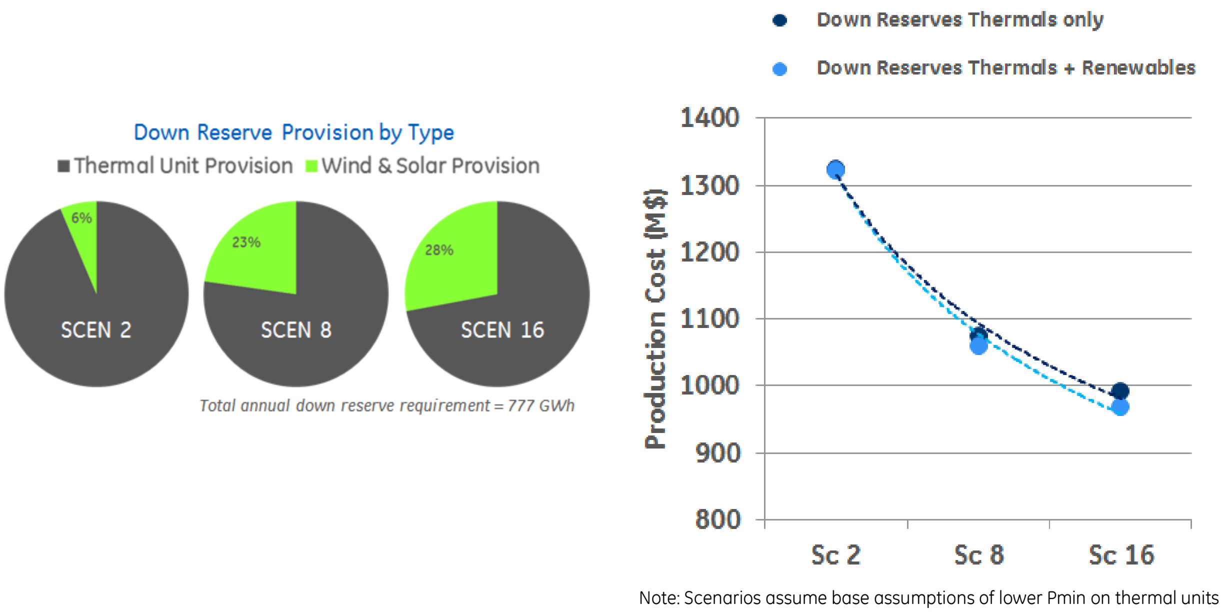


Figure 28: Value of Down-Reserves Provision from Wind and Solar Plants

5.2 Modifications Required as Renewables Penetration Increases

The modifications proposed in this section can be considered as additional pathways to enable the Oahu and Maui grids to accommodate more renewables while lowering the operating costs. The benefits from these strategies are incremental over and above the modifications proposed in the previous section. As such these strategies can be considered in the future depending on other changes occurring on the grid (load, generation, energy efficiency, etc.), future capital cost of these technologies, and associated benefits. These modifications can help to further reduce curtailment by up to 60% and operating cost by up to 45 M$ (in Scenario 16, Figure 29). As previously noted, the operating cost savings must be greater than the capital expenditure for implementing these modifications, or else the cost outweighs the benefits and the cost of electricity will be higher. These modifications are listed below in order of decreasing value:

- Further reduction in Pmins of baseload units (as described in PSIP)
- Cycling capability on baseload units
- Increased reserve contributions from non-spinning assets
- Energy storage for operating reserves
- Up-reserves from wind and solar plants

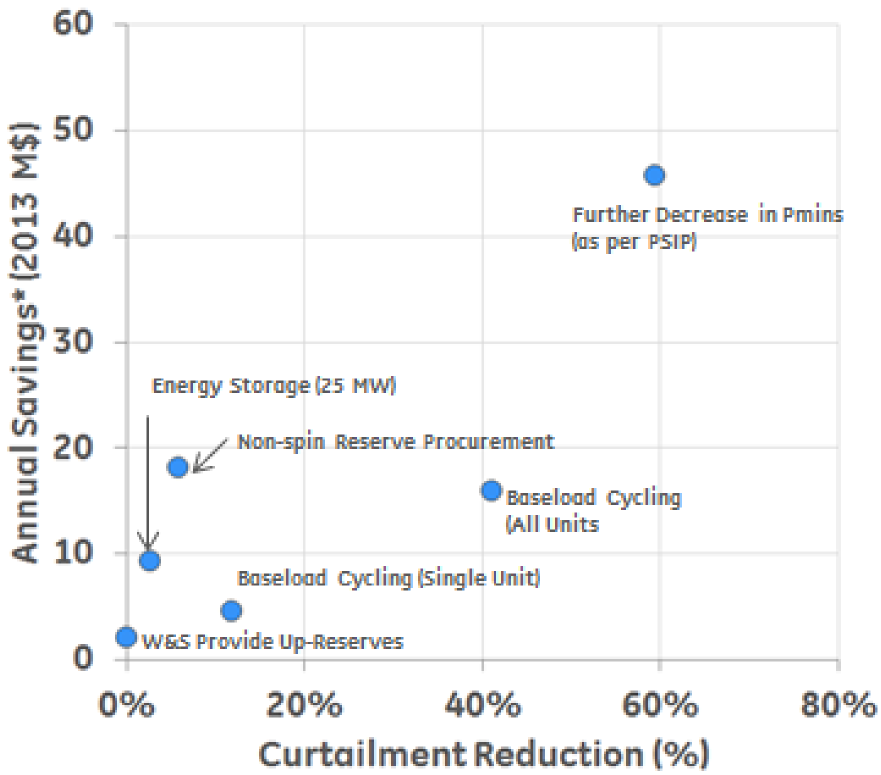


Figure 29: Proposed Modifications for the Future Grid (Scenario 16)

5.2.1 Further Reduction in Turn Down Capability of Thermal Units

Further reduction of the baseload unit turndown capability will provide significant reduction in curtailment and operating cost. The Power Supply Implementation Plan states that the minimum power levels of the baseload units could possibly be decreased to levels as low as 1 MW net output[5] (see Table 4). However, the heat rate efficiency of the units will be significantly degraded at such low power points. This study estimated new low-power heat rates by extrapolating the existing heat rate coefficients. Detailed engineering analysis by the utility must be conducted to determine the actual unit heat rates at these very low power output levels.

With the "PSIP" turndown capabilities shown in Table 4, the baseload units can further relieve 102 MW of additional capacity on the grid to accommodate new renewable generation, which can significantly reduce curtailment and enable 46 M$ of estimated annual operating cost savings (Figure 29).

[5] For Kahe 1-4 and Waiau 7-8: 1 MW net output = 5 MW gross output minus 4 MW plant auxiliary load (HECO PSIP, page 5-14)

Table 4: Further Reduction in Pmin of Oahu Baseload Units (per HECO's PSIP)

Unit Minimums (MW)

	Current	RPS Study	PSIP
Kahe 1	32.5	18.0	1.0
Kahe 2	32.7	18.1	1.0
Kahe 3	32.3	17.7	1.0
Kahe 4	32.3	17.7	1.0
Kahe 5	50.7	25.0	25.0
Kahe 6	50.0	50.0	50.0
Waiau 7	23.0	18.1	1.0
Waiau 8	23.0	18.1	1.0

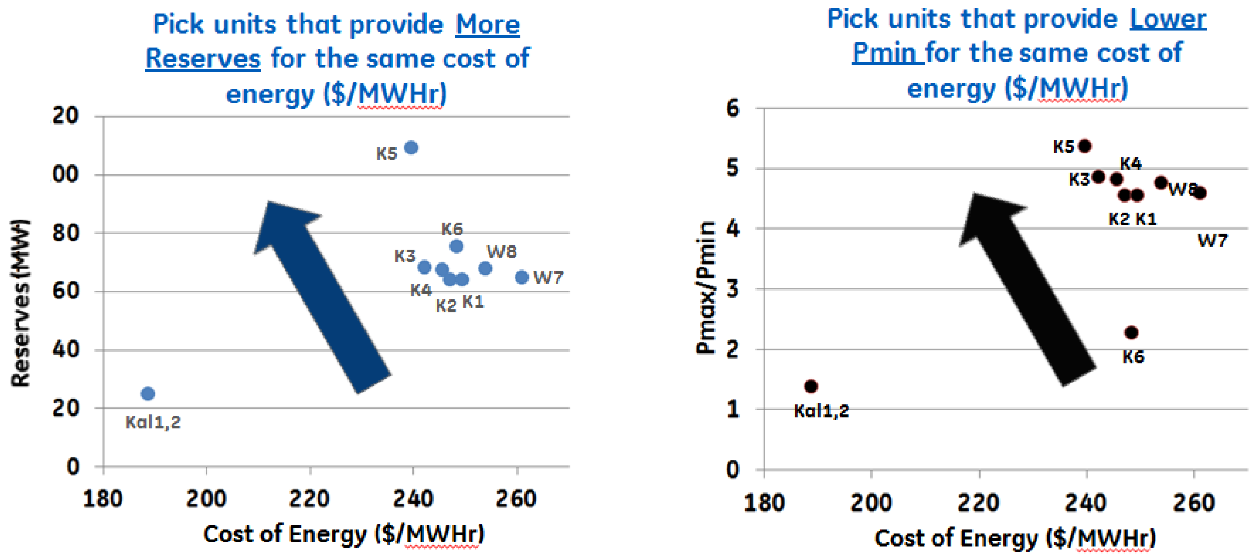
5.2.2 Cycling Capability on Baseload Units

With increased wind and solar energy penetration, the grid would benefit from having the flexibility to decommit units that may not be needed to serve the net load. Under present day operations, eight thermal units (totaling 1,161 MW of capacity) are committed for all hours of the year, unless taken offline for routine maintenance or forced outages. This can be a constraint in absorbing additional renewable energy on Oahu and Maui.

The operating reserves requirement also becomes constraining at higher renewable penetration. When operating practices allow unit cycling, units that have greater capacity to provide operating reserves must be given a higher commitment priority than units with lower capability to provide reserves. The decision of which unit to commit should not be based solely on the cost of operating the individual unit. Instead, it should take into account the cost of operating the system as a whole. As a result, the commitment strategy should seek to co-optimize a number of parameters, and should prioritize the commitment of units based on:

- Lower cost of energy, which will help to lower the production cost
- Higher capability to provide up reserves, in order to meet the operating reserves requirement with least amount of units committed
- Lower turndown capability, which will help the units to be turned down lower to absorb more renewable energy

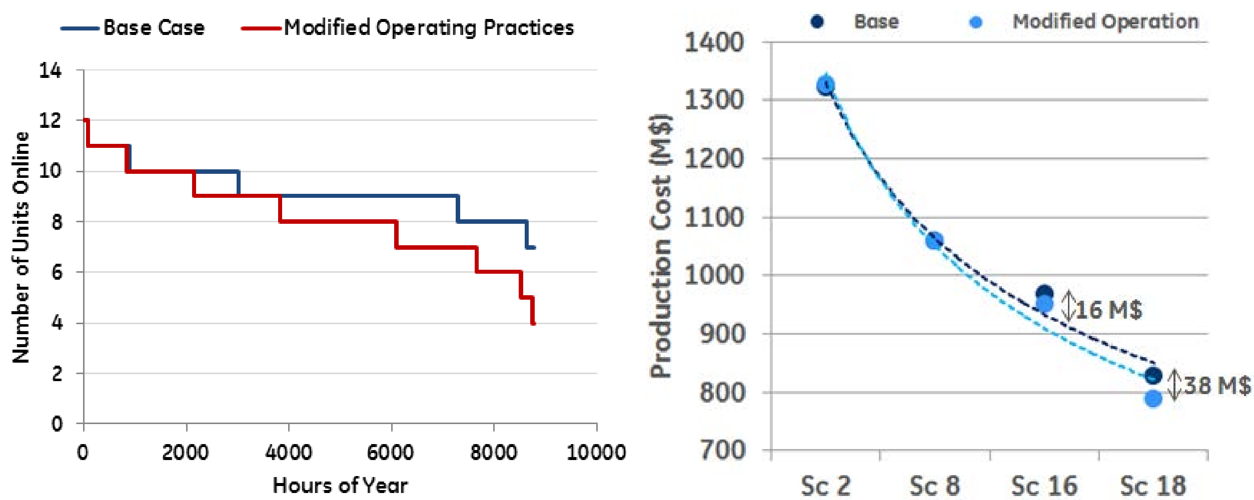
Figure 30 illustrates the methodology to commit units based on the steps described above. The arrow points to the direction that will favor a unit to be committed ahead of others. This modified commitment strategy will ensure that the system has the flexibility to commit an optimal number of units to meet the net load and operating reserves requirement, at the lowest cost to serve load. The modified commitment order shows that Kalaeloa and Kahe 6 are the least favored units and are therefore pushed down in the commitment order. Under this approach, these will be the first units to cycle off (or be decommitted) as the operator sees a high forecast of renewable energy. Kalaeloa is one of the lowest-cost units on Oahu. However, with high renewables, it is better to commit it last because of its high Pmin and its low capability to provide up-reserves, which limits the absorption of renewable energy on the grid. Note that if the Pmin of Kalealoa is reduced to a level similar to the other baseload units, this would improve its priority in the commitment order.



	Existing Commitment Order	Proposed Commitment Order	
First to Commit	AES	AES	Last to Cycle
	KAL1	K5	
	K5	K3	
	K3	W8	
	K4	K4	
	K2	K1	
	K6	K2	
	K1	W7	
	W7	K6	
Last to Commit	W8	KAL1	First to Cycle
	KAL2	KAL2	

Figure 30: Proposed Changes to Commitment Order with Unit Cycling Capability

With this modified commitment strategy, the baseload units may not be committed for all hours of the year. However, study results show that the cycling duty on the units does not increase dramatically. Instead, only the last 2-3 marginal units (Kalaeloa and Kahe 6) may be decommitted or cycled on/off during certain hours of the day. The analysis therefore shows that cycling capability is not required on all the units. Having this capability on a fraction of the baseload fleet will enable the grid to reap all the benefits from this modification. Further, this strategy is beneficial only when the renewables generation increases on the island (see Figure 31). In scenarios 16 and 18, annual operating cost savings of 16 M$ and 38 M$ can be realized. With the existing levels of renewable energy, cycling the baseload units on and off offers no apparent benefits.



Scenario 18, Units correspond to the Oahu Grid

Figure 31: Changes in Operations and Production Cost with Unit Cycling Capability

5.2.3 Strategies for Procuring Operating Reserves

With increased levels of wind and solar generation, more operating reserves are required. With existing operating practices, operating reserves are obtained from thermal units. As more reserves are required, more thermal units must be committed, which has the unfortunate consequence of increasing operating costs and increasing curtailment of renewable energy. The following strategies are suggested to improve the procurement of operating reserves:

1. Curtailed energy for operating reserves: Curtailed wind and solar energy can be used to support the operating reserves requirement. This will help to reduce the need of reserves from thermal generators. However, curtailed energy is not available at all times and therefore a control scheme must be developed to forecast when and how much curtailment may occur, so the commitment of additional thermal units can be avoided. The findings presented here assume perfect knowledge of the future and in that sense represent the maximum possible benefits. In scenario 16, curtailed wind and solar energy was able to support 4.5% of required operating reserves, thus reducing operating costs by 2 M$ annually (see Figure 32).
2. Energy storage as a reserves asset: Operating reserves may be called upon to provide energy for 10 to 30 minutes, filling the gap until an additional generation resource can be started and ramped up to deliver energy. An energy storage asset for operating reserves would need to have enough storage capacity to provide energy for this limited time period. With a 25 MW energy storage system, the Oahu grid can save 9 M$ in operating costs annually. The benefits (savings) will decrease as the renewable penetration increases because the online thermal generators will be dispatched at lower power levels and will therefore have more up-range capacity to provide reserves; thus reducing the value of energy storage asset.

3. <u>Higher contribution from non-spinning resources:</u> Operating reserves are a combination of spinning and non-spinning reserves. Spinning reserves provide the first course of action to counteract sudden loss of generation, and then non-spinning resources maybe called upon if additional support is needed. With existing practices, operating reserves are comprised primarily of spinning reserve assets. However, it may be possible to reduce the need for spinning reserves by increasing contributions from non-spinning reserve assets, through a bridging resource such as demand response or by a faster triggering strategy for quick starting units. Oahu has up to 161 MW of demand response potential, implying that up to 161 MW of non-spinning reserves can be available if needed. This can help to save as much as 18 M$ annually in Scenario 16 by avoiding to commit reserves from thermal units. Similarly, a strategy that allows all the quick starting units to be triggered simultaneously and as quickly as possible (assumes 5 min operator reaction time) can also provide up to 160 MW of additional non-spinning reserves. However, this strategy will likely increase the number of quick-starting events and therefore erode some of the projected 18 M$ annual savings.

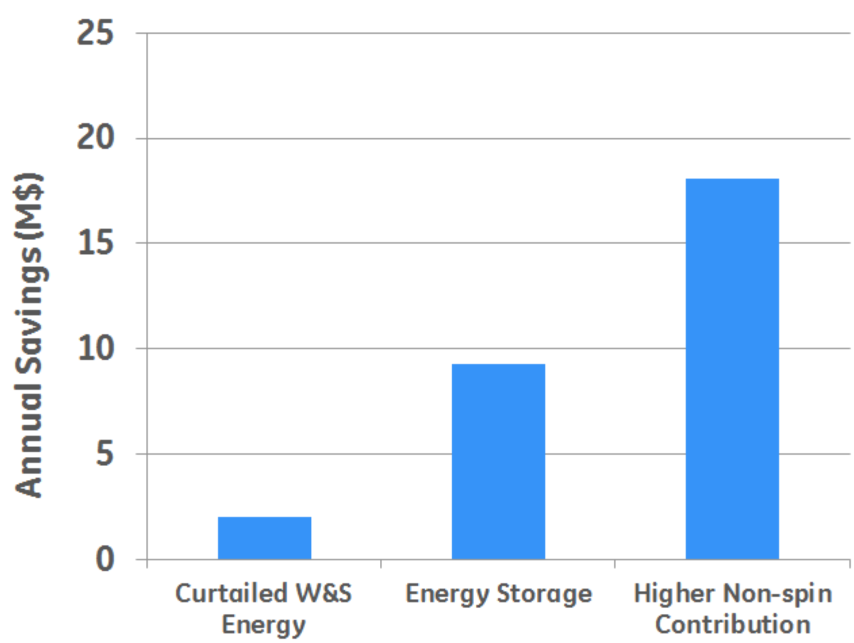


Figure 32: Comparison of Strategies to Procure Operating Reserves (Scenario 16)

6 INVESTMENT IN GRID RELIABILITY

The US mainland power grid is highly interconnected, wherein the generation shortfall in one area can be supported by its neighbors. The same is currently not true for the Hawaiian Islands. The island grids must be self-sufficient and therefore must plan for adequate generation on each individual island to meet system load demand at all times. HECO and MECO have done very well so far in maintaining high levels of grid reliability: higher than even some US mainland systems. However, the island grids are undergoing a significant transformation, with a lot of renewables coming online at the same time as many thermal generators are scheduled for retirement (per recent utility filings). This presents a need to re-examine grid reliability and generation adequacy levels on the grid, including the impacts of increasing renewable penetration. The system planners must ensure that there is sufficient installed capacity reserve margin on the grid and that other operating procedures are in place (demand response, energy efficiency, etc.) in order to fully meet the load requirements on the system.

6.1 How is the Grid Reliability Measured?

The reliability, or adequacy of supply, of a grid is measured as the sufficiency in generation resources to meet load during all hours of the year. To serve 1,000 MW of load, the grid must have more than 1,000 MW of installed generation capacity because there are several types of randomly occurring events, such as generator-forced outages or temporary technical constraints that can periodically reduce the output capability of generating units. This effect is exaggerated further for variable and intermittent resources, such as wind and solar PV, which may be producing little or no output when the grid needs them the most. Typically, power supply planners include a capacity reserve margin, which is additional generation capacity over and above the system peak load requirements, to accommodate these effects and meet load at all times. A capacity reserve margin for a US mainland power grid is typically around 15%. However, given the lack of interconnections, island systems must plan for a larger capacity reserve margin to maintain the same level of grid reliability.

Loss of load probability (LOLP) is a statistical measurement used to quantify grid reliability and is expressed in years per day. This is a measure of how often, on average, the available generating capacity of a grid is expected to fall short of the demand (system load). LOLP measures the frequency of failure and does not quantify the magnitude or duration of failure. For example, an LOLP value of 5 indicates that the generation fleet would be unable to serve the entire system load for 1 day in 5 years. Most power grids on the US mainland plan for a LOLP of 10 years/day. HECO has recently indicated that a LOLP of 4.5 to 6 years/day may be appropriate for the island power grids[6].

LOLP increases (reliability improves) as additional generation is built on the system, and conversely LOLP declines (reliability deteriorates) as generation is retired. Figure 33 illustrates

[6] Hawaiian Electric Adequacy of Supply, 2014

the relationship between LOLP and generation capacity on a system, assuming everything else is unchanged. The horizontal axis shows increasing levels of generation resources and the vertical axis shows LOLP. Initially the curve drops quickly for every MW of new generation (reliability improves), and then reliability benefit starts to saturate as more and more generation is added – implying that the marginal value of each additional MW of generation is smaller, from a resource adequacy perspective.

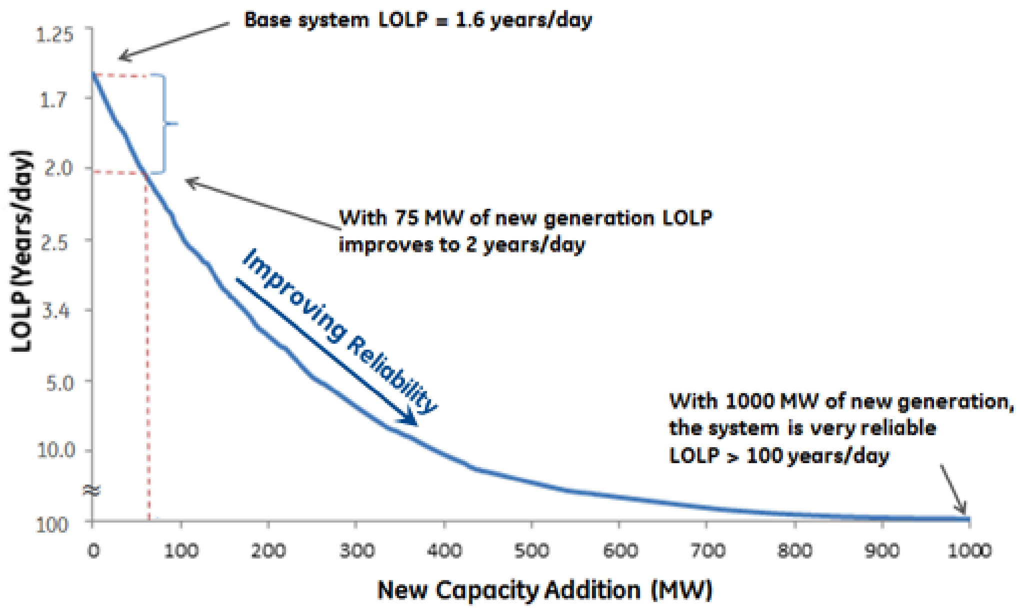


Figure 33: Reliability of a Grid with New Capacity Addition

6.2 Generation Capacity on the Island Grids is Changing

Per the 2013 IRP filings, significant changes in generation capacity are scheduled for the near term (between now and 2020). Both Oahu and Maui will retire more thermal generation capacity than will be built (Table 5). Oahu will lose 151 MW of net generation capacity (greater than 12% of peak load), while Maui will lose 46 MW of net capacity (approximately 21% of peak load). These changes will significantly impact the reliability levels on the islands if no additional capacity resources are added. Calculations performed in this study show that Oahu grid reliability will fall below HECO's desired minimum threshold of 4.5 years/day (see Figure 34). Scenario 2 shows the impact with the retirements in contrast to Scenario 1 (pre-retirement). Similarly, Maui grid reliability will deteriorate, however, it will stay above the desired minimum threshold.

Although Oahu and Maui are planning to increase the renewable generation (wind and solar) portfolio, this action alone has limited reliability benefits. Therefore, system planners must also consider alternatives for maintaining grid reliability. Some possibilities include:

- Investment in additional thermal generation
- Meeting or surpassing the energy efficiency goals

- Aggressively pursuing demand response programs
- Interconnecting Oahu and Maui with a HVDC cable

Table 5: Change in Generation Capacity until 2020

OAHU

Units Retired	Year	Capacity MWs	Units Commisioned	Year	Capacity MWs
Honolulu 8	2015	53.4	Schofield	2018	50
Honolulu 9	2015	54.4			
Waiau 3	2017	46.6			
Waiau 4	2017	46.6			
		201			50

MAUI

Units Retired	Year	Capacity MWs	Units Commisioned	Year	Capacity MWs
HC&S PPA	2018	12	ICE Unit 1	2019	16.7
K1	2019	4.7	ICE Unit 2	2019	16.7
K2	2019	4.8			
K3	2019	11			
K4	2019	13			
		46			33

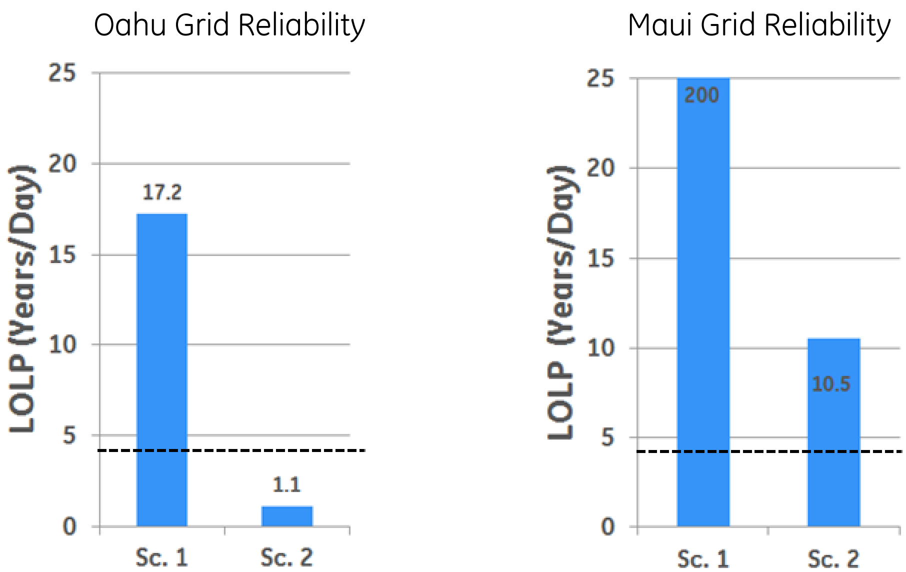


Figure 34: LOLP Reliability Levels Before and After Proposed Changes from Table 5

6.3 Wind & Solar have Limited Ability to Improve Adequacy of Supply

Intermittency and variability of wind and solar limits their ability to contribute to the grid's adequacy of supply. Solar PV generation is not available in the evening hours, when the peak of the load occurs in Hawaii, and hence increases in Solar PV will not significantly improve the reliability of the grid. Wind generation is also variable and may not always be available during critical load hours. Figure 35 shows the improvement in reliability of the Oahu grid under different scenarios of increasing renewables growth. Even in Scenario 16, with over 900 MW of new wind and solar, the reliability of the Oahu grid falls short of the minimum threshold LOLP requirement.

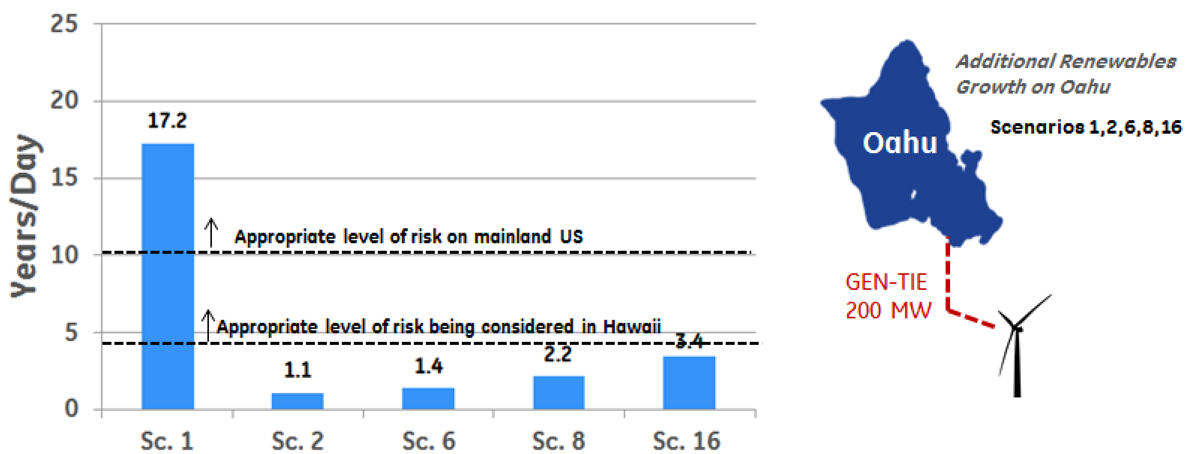
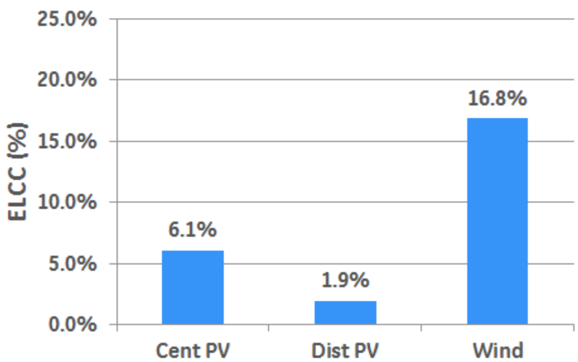


Figure 35: Oahu Grid LOLP Reliability with Increased Renewable Generation

The ability of a resource to contribute adequacy of supply is normally characterized by its capacity value. This is the amount of capacity available in a time of need, typically during peak load hours, and is expressed as a percentage of nameplate capacity. For example, a 100MW combined cycle plant that is available for operation 95% of the time would have a 95 MW capacity value.[7] On the other hand, the capacity value of new wind plant on Oahu is about 17% (see Figure 36). This means that from a resource adequacy perspective, a 100 MW wind plant would be recognized as roughly equivalent to 16 MW combined cycle plant. In another sense, to meet 100 MW of shortfall in thermal generation on Oahu, the wind capacity must grow by 600 MW, or the Central PV capacity must grow by 1600 MW. The relatively low capacity values of wind and solar resources indicate that other methods will be required to maintain grid reliability.



Resource	New Capacity Required to Meet 100 MW of Load
Cent PV	1,639
Dist PV	5,263
Wind	595

Note: Central PV is assumed to have single-axis tracking. Distributed rooftop PV has fixed panels

Figure 36: Capacity Value of Wind & Solar Resources on Oahu

6.4 Alternatives to Improve Reliability

A number of alternatives are available to improve adequacy of supply for Oahu and Maui following the retirement of existing units. This section describes several possibilities, along with preliminary evaluations of their impact on LOLP. The analysis presented here provides a preliminary estimate of benefits that can be availed from each of the options. A more rigorous cost-benefit analysis must be conducted to evaluate the viability of each approach. The benefits of decreasing system risk are inherently difficult to calculate and fundamentally rely on assumptions that quantify the costs associated with a loss of load event. Eliminating all risk of a loss of load event is not economically feasible or practical, regardless of system size.

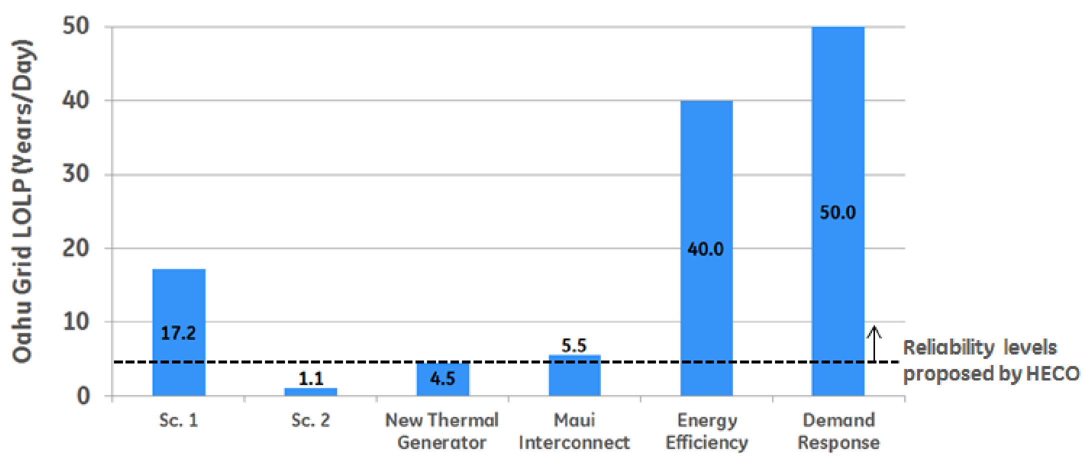
The options listed below (and shown in Figure 37) were evaluated on the Oahu grid but these options would provide similar benefits on the Maui grid as well.

- New Thermal Generation: A number of technology options are possible: combustion turbines, internal combustion engines, or combined cycle power plants. If the chosen technology is combustion turbine, approximately 78 MW of capacity would be

[7] 95% availability means that, on average, the unit is unavailable 5% of the time due to forced outages and scheduled outages.

needed to meet the required reliability levels after all of the proposed retirements occur. The capacity requirement can vary depending on the technology characteristics (outage rates & maintenance schedules) and the size of the generator.

- Interconnecting Oahu and Maui: This will help the islands to share the resources more effectively: when Oahu is short on generation, Maui may assist in shipping energy across the cable. The reliability of the Oahu grid would improve above the minimum required level of 4.5 years/day. Diversity in Oahu and Maui load profiles also contribute to the reliability improvement with the interconnection
- Energy Efficiency: The 2020 energy efficiency target approved by the PUC for the Hawaiian Islands is 2,350 GWh. Since, Oahu is the major load center, most of the energy efficiency benefits (approximately 70%) will be availed there. Energy efficiency not only helps to reduce the total annual energy consumption but it also reduces the peak load which has a significant beneficial impact on reliability. If this energy efficiency target is met, the Oahu grid reliability would be well above the required level.
- Demand Response: Recent studies show demand response potential of 160 MW on Oahu. The utility calls on demand responsive loads to reduce their consumption when there is a shortage of generation resources. This analysis assumed that 160 MW of demand responsive load is available for up to 2 hours of service during time of need. Results indicate that, on an average, demand responsive loads are called for approximately one day in a year for 2 hours. If the required infrastructure for implementing demand response is in place, it will give a significant boost to the grid reliability levels.



New Thermal Generator: 78 MW of new combustion turbines
Energy efficiency: 2020 target approved by PUC - 2350 GWh of potential for Hawaiian Islands
Demand Response: ASSESSMENT OF DEMAND RESPONSE POTENTIAL FOR HECO, HELCO, AND MECO – Global Energy Partners, LLC

Figure 37: LOLP Results for Several Alternatives to Improve Grid Reliability on Oahu

7 FUTURE WORK

The study results show that very high levels of wind and solar energy can be accommodated on the islands, reaching beyond 50% of delivered energy penetration. The RPS bill SB715, is asking the utility to support up to 100% renewable energy by 2050. This unprecedented levels of intermittent renewable energy on an island system creates new challenges for maintaining the reliability and stability of the power grid, and delivering electricity to end users in a secured manner. It is therefore suggested that the following items be evaluated in a future study work, as the islands strive forward towards meeting the RPS goals.

- Faster growth of distributed solar PV: Distributed solar PV will be a dominant renewable energy resource on the island and it is growing at a fast pace. The utility has laid out plans to improve the flexibility of the grid in the coming years to accommodate the intermittency and variability of renewables. However, the growth in distributed solar PV may outpace the proposed changes, thus requiring a different strategy and an outlook to accommodate this renewable energy resource. It is suggested that additional production cost analysis be conducted to investigate appropriate mitigation measures under very high levels of distributed solar PV.
- Stability analysis under high penetration of renewables – High penetration of wind and solar displace thermal generation and in the process deplete the grid of frequency responsive support. Contingency events like sudden loss of generation, transmission line fault, or outage at a substation can trigger frequency events that may lead to load shedding or trip of online generators, creating possibility of island wide blackouts. Additional analysis to investigate the impact on stability of the grid under very high penetrations of wind and solar resources is required.
- Energy storage for System Support: Energy storage can support the operations as well as stability of the grid under high penetration of renewables. Centrally installed storage systems can be used to reduce renewables curtailment, provision of reserves, and providing primary and secondary frequency support. Fast growth of distributed solar PV may also require bulk energy storage on the system to “synthetically” support curtailment during hours of excess generation. Distributed energy storage systems, such as those co-installed with distributed PV Solar, can be used for back-up power and time shifting of energy usage from the grid. In addition, advanced controls on distributed energy storage systems may also be used to provide ancillary services to the grid, such as frequency response,
- Distribution feeder analysis: This study evaluated the impact of high penetration of wind and solar power on the bulk transmission system. High growth of distributed generation poses additional operational challenges on the local distribution feeders. Specifically, the issues related to voltage regulation and duty cycle of substation load tap changing transformer needs to be investigated.
- Growth in electric vehicles can support the RPS goals: Electric vehicles charging can be uni-directional (absorbing energy from the grid) or bi-directional (absorbing at times and delivering back to the grid at other times). Controlled charging schemes can help to reduce the operating cost of the system and further help to reduce

renewable energy curtailment. In addition, the distributed energy storage systems can further help to reduce and optimize the system production cost by allowing the electric vehicles to charge in an appropriate manner.

- Screening to identify weak grid issues: Proliferation of power electronics based renewable generation displaces conventional thermal generation, which provide strong voltage support to the system. Power electronics inverters, in turn, rely on a stiff voltage connection to perform adequately. De-commitment of conventional synchronous generation creates weak grid conditions, which can cause control instability in the power electronics inverters. A screening analysis is suggested to identify what locations on the grid are prone to weak grid issues with increase in renewable generation so that appropriate mitigation measures can be selected.
- Optimal grid build out under specific RPS targets: This study evaluated several mitigation measures to optimize the grid operations, while meeting the RPS goals. The generation and other grid assets were fixed: no retirements or additions were analyzed. An optimal grid build out plan is needed to optimize the long term economics, looking from the viewpoint of net present value of unit retirements or new additions. It is suggested that future studies develop an optimal integrated resource plan and then investigate the efficacy of the plan on shorter time scales in production cost simulations.
- Stochastic Wind and Solar analysis: This study evaluated the impact of wind and solar integration using a single chronological year of modeled wind and solar generation data. Therefore, the results of this analysis could vary depending on the actual availability of wind and solar resources in the future. This is especially true for reliability and resource adequacy analysis. Although the results of this study simulated a typical wind and solar year, it is worth analyzing multiple years of chronological data with particular interest on the extreme scenarios.
- Compensation scheme for distributed solar PV generation: HECO has proposed to end retail net metering to compensate distributed solar PV. Net metering unfairly transfers the benefits to distributed solar PV generation from other retail customers. Distributed solar PV installations are forecasted to increase at fast rate in the coming years. It is therefore recommended that future analysis be done to develop suitable economic-financial models as compensation mechanism for distributed solar PV generation.
- Valuation of ancillary services: As more and more renewables come online, ancillary services become an important part of grid operations. RSWG has conducted analysis to establish a methodology for valuing ancillary services. The future work should use the methodology to determine valuations for essential and new ancillary services: such as frequency support from central and distributed resources, regulation and bridging support from central and distributed resources, etc.

8 APPENDIX

8.1 Load and Fuel Price Assumptions

Table 6: Load and Fuel Price Assumptions

	Peak Demand (MW)	Annual Energy (GWh)
Oahu	1,279	7,769
Maui	200	1,172

	Fuel Price 2013$/MMBTU
OAHU	
Biodiesel	$45.93
Diesel	$21.49
LSFO	$18.64
ULSD	$22.67
MAUI	
Biodeisel	$46.84
Diesel	$23.56
LSFO	$18.92
MSFO	$16.12
ULSD	$24.47

8.2 Thermal Generating Characteristics

Table 7: Thermal Generating Unit Properties

Property	Unit Type	Primary Fuel	Primary Fuel	Max Capacity	P-Min (Scen 1)	P-Min (Scen 2-18)	Heat Rate Coef (A)	Heat Rate Coef (B)	Heat Rate Coef (C)	Full Load Heat Rate	VOM	Forced Outage Rate	Min Down Time	Min Up Time	Fixed Op. Sch.	Start Energy (Cold)	Start Energy (Hot)
Units		(Scen 1)	(Scen 2-18)	MW	MW	MW	MMBTU/HR	BTU/KWH	BTU/KWH²	BTU/KWH	$/MWH	%	HRS	HRS	Y/N	MBTU	MBTU
AES	Baseload	Coal	Coal	180	63.0	63.0	PPA	PPA	PPA	PPA	N/A	1.5%	N/A	N/A	Y	N/A	N/A
Kahe 1	Baseload	LSFO	Diesel	82.1	32.5	18.0	60.278	8.618	0.009	10,087	0.32	3.6%	6	3	Y	5,044	933
Kahe 2	Baseload	LSFO	Diesel	82.1	32.7	18.1	73.156	7.958	0.014	9,990	0.32	3.6%	6	3	Y	5,044	933
Kahe 3	Baseload	LSFO	Diesel	86.1	32.3	17.7	73.462	7.758	0.014	9,794	0.32	5.2%	6	3	Y	5,044	933
Kahe 4	Baseload	LSFO	Diesel	85.3	32.3	17.7	72.423	8.508	0.007	9,933	0.32	5.2%	6	3	Y	5,044	933
Kahe 5	Baseload	LSFO	Diesel	134.3	50.7	25.0	89.066	8.616	0.003	9,688	0.32	3.2%	6	3	Y	4,586	1,352
Kahe 6	Baseload	LSFO	Diesel	134.4	50.0	50.0	116.696	8.156	0.008	10,055	0.32	2.1%	6	3	Y	9,274	2,703
Kalaeloa CC1	Baseload	LSFO	LSFO	90.0	65.0	65.0	PPA	PPA	PPA	PPA	N/A	1.5%	5	3	Y	800	800
Kalaeloa CC2	Baseload	LSFO	LSFO	90.0	65.0	65.0	PPA	PPA	PPA	PPA	N/A	1.5%	5	3	N	800	800
Kalaeloa CC3	Baseload	LSFO	LSFO	28.0	N/A	N/A	PPA	PPA	PPA	PPA	N/A	1.5%	1	3	N	0	0
Waiau 7	Baseload	LSFO	Diesel	82.9	23.0	18.1	106.045	7.418	0.022	10,555	0.32	5.2%	6	3	Y	5,044	933
Waiau 8	Baseload	LSFO	Diesel	86.1	23.0	18.1	63.762	8.669	0.010	10,267	0.32	5.2%	6	3	Y	5,044	933
Honolulu 8*	Cycling	LSFO	N/A	53.4	22.3	N/A	36.300	10.279	0.006	11,261	0.32	15.1%	5	3	N	190	190
Honolulu 9*	Cycling	LSFO	N/A	54.4	22.3	N/A	69.674	8.921	0.022	11,397	0.32	15.1%	5	3	N	190	190
Waiau 3*	Cycling	LSFO	N/A	46.6	22.3	22.3	146.083	4.796	0.085	11,900	0.32	15.0%	5	3	N	337	337
Waiau 4*	Cycling	LSFO	N/A	46.6	22.3	22.3	49.306	9.282	0.032	11,828	0.32	12.0%	5	3	N	337	337
Waiau 5	Cycling	LSFO	Diesel	54.5	22.5	22.5	60.869	8.786	0.030	11,523	0.32	4.7%	5	3	N	277	277
Waiau 6	Cycling	LSFO	Diesel	53.5	22.5	22.5	63.911	8.713	0.032	11,614	0.32	4.7%	5	3	N	277	277
Waiau 9	Peaking	Diesel	Diesel	52.9	N/A	N/A	N/A	N/A	N/A	12,913	3.75	10.9%	1	1	N	36	36
Waiau 10	Peaking	Diesel	Diesel	49.9	N/A	N/A	N/A	N/A	N/A	12,307	3.98	10.9%	1	1	N	33	33
CIP CT	Peaking	Biodiesel	Biodiesel	113	N/A	N/A	N/A	N/A	N/A	11,688	40.76	15.0%	1	1	N	126	126
Airport DSG	Peaking	Biodiesel	Biodiesel	8	N/A	N/A	N/A	N/A	N/A	10,205	37.46	4.0%	1	1	N	126	126
Schofield**	Peaking	N/A	Biodiesel	48.84	N/A	N/A	N/A	N/A	N/A	8,894	21.15	4.0%	1	1	N	6	6
H-Power	Firm RE	Waste	Waste	68	N/A	N/A	PPA	PPA	PPA	PPA	N/A	N/A	N/A	N/A	Y	N/A	N/A
Honua	Firm RE	Waste	Waste	6	N/A	N/A	PPA	PPA	PPA	PPA	N/A	N/A	N/A	N/A	Y	N/A	N/A
Kahului 1*	Baseload	MSFO	N/A	4.7	2.3	N/A	8.868	12.231	0.282	15,445	1.42	N/A	7	1	Y	36	36
Kahului 2*	Baseload	MSFO	N/A	4.8	2.3	N/A	7.931	11.926	0.411	15,551	1.22	N/A	7	1	Y	36	36
Kahului 3*	Baseload	MSFO	N/A	11.0	7.0	N/A	28.854	8.024	0.236	13,249	1.15	N/A	12	1	Y	279	279
Kahului 4*	Baseload	MSFO	N/A	11.9	7.0	N/A	33.992	7.848	0.259	13,786	1.13	N/A	12	1	Y	279	279
Maalaea CC1	Baseload	Diesel	Diesel	53.0	35.0	35.0	94.184	5.904	0.015	8,494	4.70	0.3%	13	1	Y	233	233
Maalaea CC2	Baseload	Diesel	Diesel	52.8	35.0	18.5	74.108	7.230	0.006	8,513	4.70	0.7%	4	4	Y/N	233	233
Maalaea 1	Peaking	Diesel	Diesel	2.5	N/A	N/A	N/A	N/A	N/A	10,288	25.63	8.5%	1	1	N	1	1
Maalaea 2	Peaking	Diesel	Diesel	2.5	N/A	N/A	N/A	N/A	N/A	10,288	25.63	8.5%	1	1	N	1	1
Maalaea 3	Peaking	Diesel	Diesel	2.5	N/A	N/A	N/A	N/A	N/A	10,288	25.63	8.5%	1	1	N	1	1
Maalaea 4	Peaking	Diesel	Diesel	5.5	N/A	N/A	18.997	1.180	1.002	10,149	26.96	1.8%	1	1	N	5	5
Maalaea 5	Cycling	Diesel	Diesel	5.5	1.9	1.9	18.997	1.180	1.002	10,149	26.96	1.8%	1	1	N	5	5
Maalaea 6	Peaking	Diesel	Diesel	5.5	N/A	N/A	18.997	1.180	1.002	10,149	26.96	1.8%	1	1	N	5	5
Maalaea 7	Cycling	Diesel	Diesel	5.5	1.9	1.9	18.997	1.180	1.002	10,149	26.96	1.8%	1	1	N	5	5
Maalaea 8	Cycling	Diesel	Diesel	5.5	1.9	1.9	25.624	-2.922	1.477	9,848	17.66	0.7%	1	1	N	13	13
Maalaea 9	Cycling	Diesel	Diesel	5.5	1.9	1.9	25.624	-2.922	1.477	9,848	17.83	0.7%	1	1	N	13	13
Maalaea 10	Cycling	Diesel	Diesel	12.3	7.9	7.9	24.598	3.762	0.289	9,323	11.36	0.5%	2	1	N	43	43
Maalaea 11	Cycling	Diesel	Diesel	12.3	7.9	7.9	24.598	3.762	0.289	9,323	11.36	0.5%	2	1	N	43	43
Maalaea 12	Cycling	Diesel	Diesel	12.3	7.9	7.9	24.598	3.762	0.289	9,323	11.36	0.5%	2	1	N	42	42
Maalaea 13	Cycling	Diesel	Diesel	12.3	7.9	7.9	24.598	3.762	0.289	9,323	11.96	0.5%	2	1	N	42	42
Maalaea X1	Peaking	Diesel	Diesel	2.5	N/A	N/A	N/A	N/A	N/A	10,288	25.63	8.5%	1	1	N	1	1
Maalaea X2	Peaking	Diesel	Diesel	2.5	N/A	N/A	N/A	N/A	N/A	10,288	25.63	8.5%	1	1	N	1	1
New ICE**	Peaking	N/A	Biodiesel	16.7	N/A	N/A	14.680	6.588	0.052	8,339	21.15	4.0%	1	1	N	11	11
New ICE**	Peaking	N/A	Biodiesel	16.7	N/A	N/A	14.680	6.588	0.052	8,339	21.15	4.0%	1	1	N	11	11
HC&S*	Firm RE	Biomass	N/A	13.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	Y	N/A	N/A

Notes

[1] * Indicates a unit was assumed to retire for Scenarios 2-18
[2] ** Indicates a unit was assumed to be installed for Scenarios 2-18
[3] Heat rates for AES and Kalaeloa are based on PPA contracts rather than technical specifications
[4] Firm RE represents biomass and waste-to-energy plants that operate at fixed dispatch levels unless on outage
[5] Properties in this table represent the Baseline scenarios only and may have been altered for sensitivity analysis

8.3 Annual Generation (GWh) by Type, by Scenario

Table 8: Annual Generation (GWh) by Type, Scenarios 1 - 9

	SCEN 1	SCEN 2	SCEN 3	SCEN 4	SCEN 5	SCEN 6	SCEN 7	SCEN 8	SCEN 9
OAHU	**7,768.8**	**7,765.1**	**7,765.3**	**7,765.5**	**7,765.3**	**7,765.4**	**7,765.7**	**7,765.5**	**7,765.7**
Baseload	6,035.0	6,117.2	5,752.0	5,485.6	5,258.5	5,452.3	5,187.2	4,906.1	4,944.0
Cycling	455.2	210.8	195.6	181.0	169.7	175.2	159.1	144.9	144.9
Peaking	1.0	34.7	27.7	24.7	24.4	21.4	19.4	20.0	19.1
Biodiesel	12.5	135.4	102.5	90.9	87.9	79.3	71.9	71.2	68.8
Wind	295.6	297.5	297.5	593.2	834.8	297.5	587.6	567.5	566.8
Central Solar	21.3	21.3	379.7	379.8	379.8	568.0	568.8	724.5	531.1
Distributed Solar	351.2	351.2	413.3	413.3	413.3	574.8	574.8	734.4	893.9
Firm Renewable	597.1	597.1	597.1	597.1	597.1	597.1	597.1	597.1	597.1
MAUI	**1,172.1**	**1,172.1**	**1,172.1**	**1,172.1**	**1,172.1**	**1,172.1**	**1,172.1**	**1,172.1**	**1,172.1**
Baseload	764.8	683.5	683.5	683.5	683.5	683.5	683.5	683.5	683.5
Cycling	31.8	114.3	114.3	114.3	114.3	114.3	114.3	114.3	114.3
Peaking	0.3	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9
Biodiesel		0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Wind	212.9	302.3	302.3	302.3	302.3	302.3	302.3	302.3	302.3
Central Solar									
Distributed Solar	65.7	65.7	65.7	65.7	65.7	65.7	65.7	65.7	65.7
Firm Renewable	96.6								
TOTAL	**8,941.0**	**8,937.2**	**8,937.4**	**8,937.7**	**8,937.5**	**8,937.6**	**8,937.9**	**8,937.6**	**8,937.8**

Table 9: Annual Generation (GWh) by Type, Scenarios 10 - 18

	SCEN 10	SCEN 11	SCEN 12	SCEN 13	SCEN 14	SCEN 15	SCEN 16	SCEN 17	SCEN 18
OAHU	**7,790.3**	**6,957.6**	**7,020.4**	**7,788.9**	**7,007.7**	**7,109.0**	**7,786.2**	**7,156.5**	**7,293.8**
Baseload	5,090.5	5,045.1	4,433.5	4,800.4	4,781.0	4,201.4	4,369.9	4,349.9	3,895.5
Cycling	165.9	154.8	110.9	148.1	128.6	100.6	122.0	107.6	88.8
Peaking	24.2	13.9	9.2	20.7	12.4	9.5	19.5	11.9	9.8
Biodiesel	87.3	56.4	38.7	75.3	47.4	36.8	68.4	44.0	36.1
Wind	1,032.3	297.5	1,038.1	1,004.3	297.5	1,019.7	1,148.6	575.6	1,195.1
Central Solar	379.8	379.7	379.7	568.4	569.0	569.3	726.3	736.0	737.0
Distributed Solar	413.3	413.3	413.3	574.8	574.8	574.8	734.4	734.4	734.4
Firm Renewable	597.1	597.1	597.1	597.1	597.1	597.1	597.1	597.1	597.1
MAUI	**1,172.1**	**2,015.7**	**1,966.0**	**1,172.1**	**1,961.5**	**1,873.5**	**1,172.1**	**1,807.8**	**1,682.0**
Baseload	648.0	701.7	588.8	648.0	669.1	555.0	648.0	599.5	506.9
Cycling	92.1	20.7	12.4	92.1	18.6	11.8	92.1	16.1	10.8
Peaking	4.9	21.9	14.9	4.9	17.7	13.6	4.9	15.7	12.9
Biodiesel	0.4	2.3	1.6	0.4	2.2	1.7	0.4	2.1	1.8
Wind	298.6	1,141.0	1,026.0	298.6	1,125.7	981.7	298.6	1,046.1	869.3
Central Solar			194.0			181.6			152.0
Distributed Solar	128.2	128.2	128.2	128.2	128.2	128.2	128.2	128.2	128.2
Firm Renewable									
TOTAL	**8,962.4**	**8,973.3**	**8,986.4**	**8,961.1**	**8,969.2**	**8,982.6**	**8,958.3**	**8,964.3**	**8,975.8**

8.4 Operating Rules and Assumptions

Unit commitment: Thermal units are committed to meet the net load and required ancillary services requirements (up and down reserves). Figure 38 shows the provision of up and down reserves from a thermal unit. Further, the commitment and dispatch of thermal units includes start-up cost, variable operating & maintenance cost and fuel cost.

Contingency Up Reserves: This is modeled as the loss of the biggest generating unit or the HVDC connection on Oahu. For example, in scenario 2, contingency up-reserves is the loss of AES = 180 MW; in scenario 18, contingency up-reserves is the loss of HVDC cable between Oahu and Maui. Every hour of the year is modeled to carry contingency up reserves by committing appropriate number of generating units. All of the HECO baseload units are modeled to provide a portion of the contingency reserves.

Operating Up Reserves: This is modeled as the required capacity to respond adequately to wind and solar variability. A method was developed in Hawaii Solar Integration Study for procurement of operating reserves based on the intra hour variability of wind and solar. This study used the same methodology with the criterion of meeting 99.9% of intra hour variability to procure the required level of operating reserves. Spinning reserves portion of the total operating reserves requirement is shown in Figure 39-Figure 41.

Contingency Down Reserves: This is modeled as the loss of substation serving load equivalent to 10% of online system load on Oahu. Loss of substation can occur due to transmission or a distribution outage. This ancillary service is modeled by intentionally dispatching online generation over and above the minimum operating levels. All of the baseload HECO units and utility scale wind and solar generating were modeled to provide down reserves.

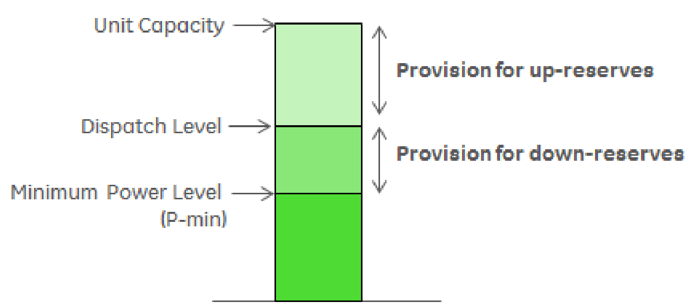


Figure 38: Unit Commitment for Procurement of Reserves

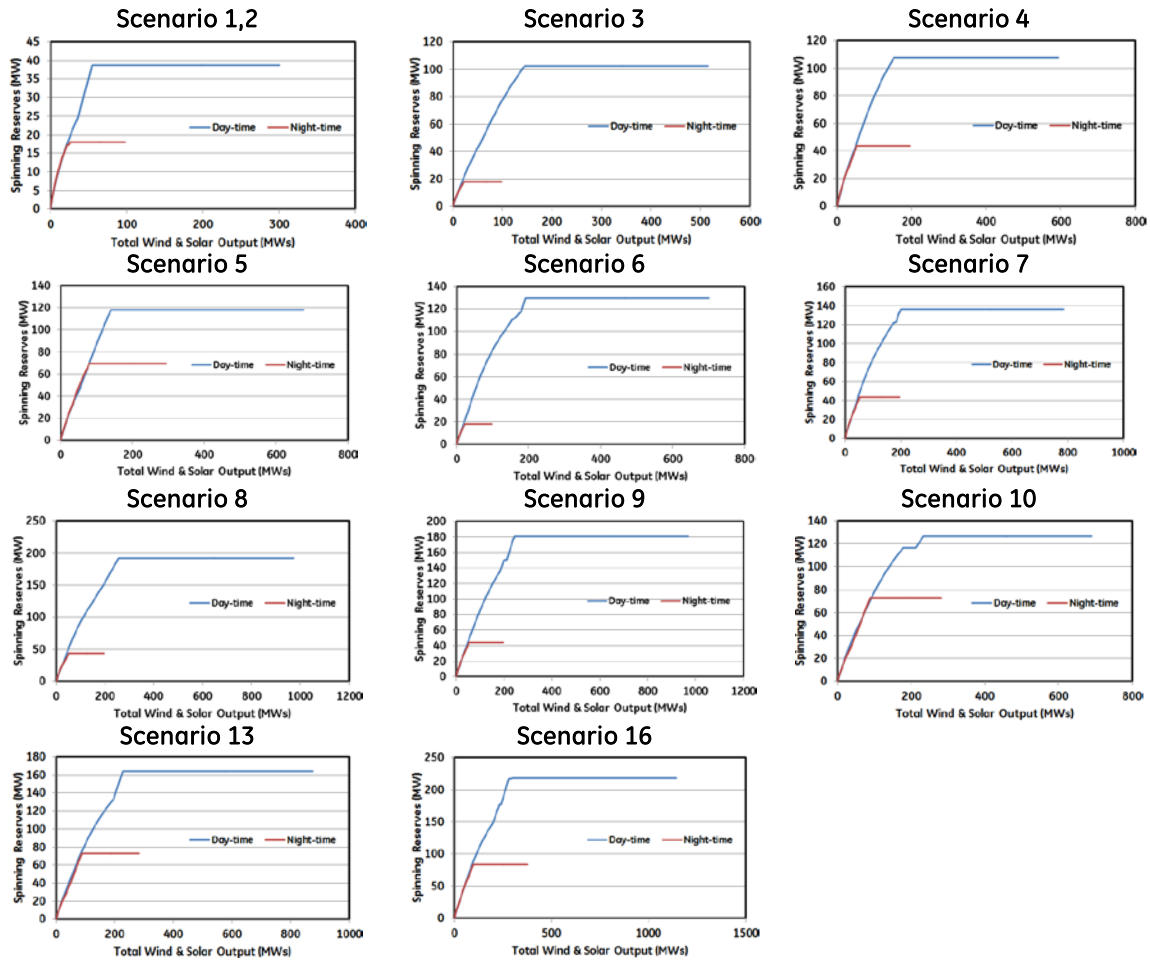


Figure 39: Spinning Reserves Portion of Operating Reserves – Oahu

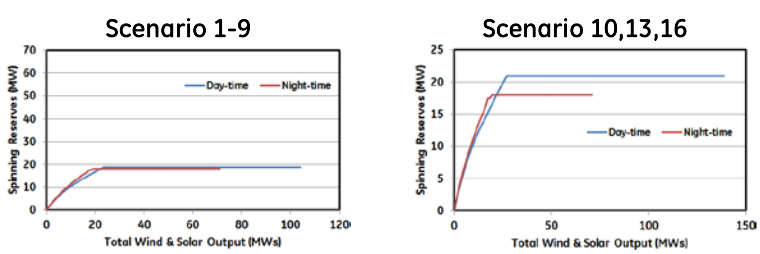


Figure 40: Spinning Reserves Portion of Operating Reserves – Maui

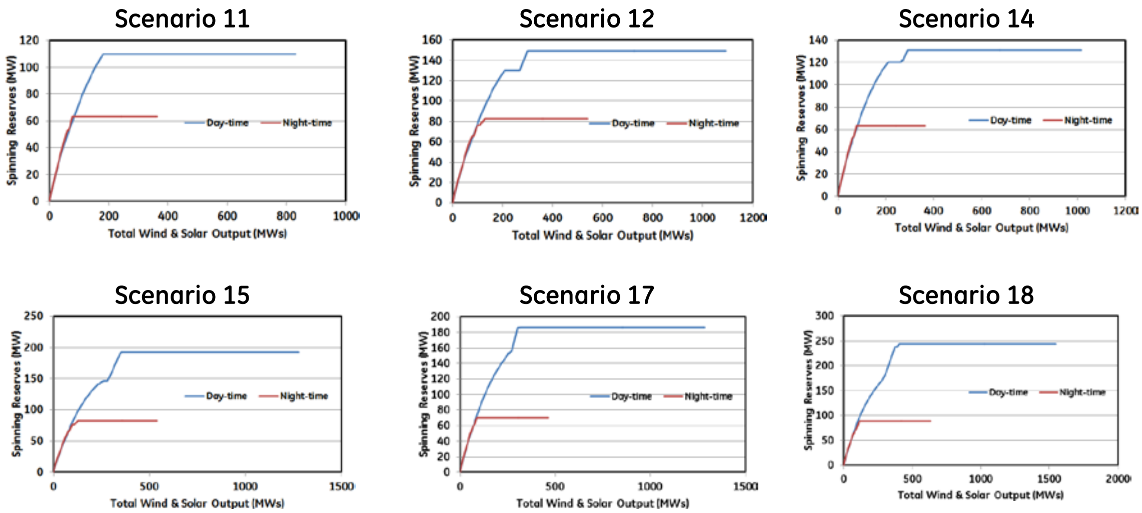


Figure 41: Spinning Reserves Portion of Operating Reserves – Grid-Tie

8.5 Reliability and Resource Adequacy Assumptions

Table 10: Forced Outage Rates

Oahu Thermal Units	Forced Outage Rate
H8	8.5%
H9	8.5%
W3	6.7%
W4	3.8%
W5	2.0%
W6	2.0%
W7	3.7%
W8	3.7%
W9	7.2%
W10	7.2%
K1	3.6%
K2	3.6%
K3	3.7%
K4	3.7%
K5	4.7%
K6	4.7%
CIPCT1	8.2%
Kal 1	1.5%
Kal 2	1.5%
AES	1.5%
Airport DG	2.2%
Schofield Barracks	4.0%

Maui Thermal Units	Forced Outage Rate
X1	8%
X2	8%
M1	8%
M2	8%
M3	8%
M4	2%
M5	2%
M6	2%
M7	2%
M8	1%
M9	1%
M10	1%
M11	1%
M12	1%
M13	1%
M1415	0%
M1516	0%
M1718	1%
M1819	1%
K1	0%
K2	0%
K3	0%
K4	0%
ICE Units	4%

HVDC	Forced Outage Rate
Oahu - Maui	2%
Oahu - Maui county	2%

Table 11: Planned Maintenance

Oahu Thermal Units	Planned Maintenance		
H8	29-Mar	:	10-Apr
H9	3-May	:	26-Jun
W3	18-Sep	:	9-Oct
W4	30-Oct	:	20-Nov
W5	19-Jun	:	14-Jul
W6	9-Aug	:	1-Sep
W7	2-Apr	:	21-Apr
W8	26-Jan	:	14-Feb
W9	16-Feb	:	24-Apr
W10	3-May	:	10-Jul
K1	1-Jul	:	22-Jul
K2	23-Apr	:	12-May
K3	24-Jul	:	16-Oct
K4	21-May	:	9-Jun
K5	12-Mar	:	31-Mar
K6	2-Jan	:	9-Jan
CIPCT1	27-Jul	:	30-Jul
Kal 1	12-Jan	:	25-Jan
Kal 2	19-Jan	:	15-Feb
AES	17-Feb	:	4-Mar

Maui Thermal Units	Planned Maintenance		
K1	18-May	:	4-Jun
K2	4-May	:	7-May
K3	2-Mar	:	3-Mar
K4	16-Mar	:	31-Mar
M1415	6-Jan	:	10-Jan
M1516	31-Aug	:	30-Sep
M1718	1-Jun	:	1-Jun
M1819	30-Mar	:	28-Apr