July 29, 2022

The Honorable Chair and Members
of the Hawai‘i Public Utilities Commission
Kekuanao‘a Building, First Floor
465 South King Street
Honolulu, Hawai‘i 96813

Dear Commissioners:

Subject: Docket No. 2017-0352 – To Institute a Proceeding Relating to a Competitve Bidding Process to Acquire Dispatchable and Renewable Generation
Docket No. 2018-0165 – Instituting a Proceeding to Investigate Integrated Grid Planning
Updated O‘ahu and Maui Island Near Term Grid Needs Assessment

In accordance with Ordering Paragraph No. 2 of Order No. 38479,[1] issued on June 30, 2022 in the subject proceeding, the Hawaiian Electric Companies[2] respectfully submit the attached July 29, 2022 *O‘ahu Near-Term Grid Needs Assessment* and *Maui Near-Term Grid Needs Assessment* as Attachment 1 and Attachment 2, respectivley. This report describes the methodology and inputs used to study scenarios whose results were then used to inform recommendations for Grid Needs for solution sourcing for the Stage 3 Request for Proposals (“RFP”) for O‘ahu and Maui Island, which the Companies plan to discuss at the RFP stakeholder conference through a virtual meeting scheduled for August 5, 2022 from 1:00 to 3:00 pm HST. A virtual meeting invitation has been emailed to Integrated Grid Planning participants and the competitive bidding distribution list. Other interested parties may contact OahuRenewableRFP@hawaiianelectric.com for meeting information. A recording of the meeting and presentation slides will be posted at https://www.hawaiianelectric.com/clean-energy-hawaii/selling-power-to-the-utility/competitive-bidding-for-system-resources/stage-3-oahu-rfp when available.

The Companies look forward to working with the Commission, the Independent Observer, and stakeholders to finalize the RFP and launching a competitive and successful procurement.

[1] Ordering Paragraph No. 2 of Order No. 38479 provided: “The HECO Companies shall file an updated Near-term Grid Needs Assessment for Oahu and Maui Island within 30 days of this Order[.]”

[2] “Hawaiian Electric Companies” or “Companies” are Hawaiian Electric Company, Inc., Hawai‘i Electric Light Company, Inc., and Maui Electric Company, Limited.

Hawaiian Electric PO BOX 2750, HONOLULU, HI 96840-0001

Sincerely,

/s/ Marc Asano

Marc Asano
Director, Integrated Grid Planning

Enclosure

c: Service List

Hawai‘i Powered

O’ahu Near-Term Grid Needs Assessment

JULY 2022

Hawaiian Electric

Contents

List of Figures

1 EXECUTIVE SUMMARY

Hawaiian Electric's Climate Change Action Plan to reduce greenhouse gases 70% from 2005 levels by 2030 is bold and ambitious, setting Hawaiʻi on a track to achieve net zero carbon emissions economywide by 2045. The path to a more sustainable Hawaiʻi is rooted in our clean energy vision, Hawaiʻi Powered: Clean energy for Hawaiʻi, by Hawaiʻi. It's about working with everyone – stakeholders, communities, customers, and employees, together – to find the right solutions to create an affordable, sustainable, reliable and resilient energy system for future generations. Achieving a decarbonized economy while balancing these objectives is the challenge that lies before us.

The changing nature in the way customers consume electricity and adopt new technologies like electric vehicles and battery energy storage, along with customers' increased reliance on electricity to power their daily routine necessitates a different approach to grid reliability, identification of grid needs, and acquisition of the right solutions. With the "clean" economy having greater reliance on electric supply, customers will expect reliable and resilient electric service with less tolerance for even short duration outages. These are the complex engineering problems to be solved.

There are also interrelated, near-term issues that must be addressed. First, an issue that Hawaiʻi residents are all too familiar with – volatile oil prices that drive much of the energy economy; highlighted by the recent Russia-Ukraine conflict. Next, an issue that threatens to become systemic – a fleet of 70-year-old generators that has far outlived its original designed life with decreasing availability over the past decade because of their age and the manner in which they are now operated. As more intermittent sources of energy are integrated onto the grid, these generators can no longer operate at a steady pace 24 hours a day, seven days a week. Instead, they are being asked to jog, sprint, start and stop on a daily basis. Environmental regulations and compliance will also necessitate new types of flexible and base-loaded firm generation in the future.

This report establishes a roadmap to get us there, showing how we can reduce carbon emissions and fossil-fuel consumption, improve generation reliability and diversify the renewable energy portfolio to better withstand climate-related or extreme events.

In developing this roadmap, Hawaiian Electric performed technical analyses grounded in the following objectives:

- Add new low-cost variable renewable energy to further decarbonize the electricity sector and reduce fossil-fuel use
- Improve generation reliability through the careful replacement of existing firm generation with the right mix of variable renewables and energy storage backed by renewable firm generation
- Diversify the resource portfolio to be more resilient despite weather-dependent generation
- Modernize aging generation infrastructure (a fleet with more flexible resources to complement wind, solar and battery energy storage projects)
- Acquire more flexibility for the current and future generation system (building on the renewable dispatchable solar generation and aggregated grid service resources acquired to date)

The key findings of the grid needs assessment include:

- Reductions in greenhouse gas emissions and fossil-fuel use can be achieved through continued additions of customer and grid-scale low-cost, zero-emission generation resources like solar and wind. This includes distribution system enhancements and eventual creation of renewable energy zones and new transmission infrastructure to integrate higher amounts of grid-scale renewable resources, which should be pursued in collaboration with communities, landowners and renewable energy developers.
- Flexible customer resources such as private rooftop solar, distributed energy storage, electric vehicles, and energy efficiency measures play a central role in reducing carbon emissions and reducing supply side energy and capacity needs. By 2030, this includes approximately 1,000 gigawatt hours of energy efficiency (GWh), 250 megawatts (MW) of private rooftop solar and 150 MW / 400 MWh of customer battery energy storage.
- Over the next five years, at least 544 GWh of grid-scale renewable energy should be procured, leveraging existing infrastructure to facilitate quicker interconnection. Producing greater amounts of renewable energy will require development of renewable energy zones.
- Modernizing the firm generation fleet along with new variable renewable and energy storage resources will improve generation reliability. The addition of 500-700 MW of renewable firm generation is needed to meet expected greater demand due to electrification of transportation and buildings and reduce the probability of generation outages while improving operational flexibility to better integrate variable renewable generation. This addition of renewable firm generation could allow for the removal or deactivation of up to 930 MW of older, less flexible fossil-fuel generation by 2033.
- A diversified energy portfolio that includes renewable firm power additions creates a more resilient generation system to better withstand and/or recover from climate-related and extreme events, which are increasing in frequency and can significantly affect generation output.

We must urgently address these needs through a balanced portfolio of renewable resources including customer resources, renewable firm generation alongside renewable dispatchable energy resources such as wind, solar and battery energy storage.

The near-term needs of the grid

The grid needs assessment identified commercially available renewable resources and technologies that would cost-effectively ensure near-term reliability on Oʻahu. In the near-term Hawaiian Electric will rely upon technologies such as wind, solar, battery energy storage, advanced inverters and renewable firm generation. This grid needs assessment follows the integrated grid planning (IGP) process to assess Oʻahu's grid needs based on:

- Capacity expansion optimization analysis to add new least-cost resources
- Reliability assessment of the system
- Validation of future system operations through production cost simulations.

The detailed reliability assessment included a probabilistic resource adequacy evaluation that incorporated a methodology consistent with industry best practices, reviewed and supported by the technical advisory panel (TAP), an independent group of technical experts from utilities, market operators and research organizations that meets periodically to consult with Hawaiian Electric on the IGP process and the more technical aspects of our transition to 100%

renewable energy. The resource plans for the scenarios considered in this assessment are included in Section 6.3 and Section 9.1 for reference.

The assessment considered a range of future scenarios bookended by two possible futures: One where load dramatically increases due to electric vehicle growth (i.e., "high load scenario") and one where load decreases due to high customer adoption of efficiency measures like light-emitting diode (LED) lighting, heat pump water heaters and distributed energy resources (i.e., "low load scenario"). Across this range of scenarios, the optimal resource mix includes low-cost renewable energy that may include grid-scale solar, land-based and offshore wind, and battery energy storage.

Customer technologies play a central role in all pathways to 2030 and beyond. Significant amounts of customer-implemented energy efficiency and private rooftop solar and storage will reduce grid-scale resource needs. These resources have the potential to provide the desired flexibility to enable efficient grid operations and meet needs for electric vehicle charging. Hawaiian Electric and its industry partners will need to continue aggressive pursuit of these resources through programs, pricing and procurements. Further analysis in this area will continue throughout the IGP process.

Firm Generation

In this report, firm generation refers to a synchronous machine based technology that is available at any time under system operator dispatch for as long as needed, except during periods of outage and deration, and is not energy limited or weather dependent.

Low-cost renewables backed by renewable firm generation continues to be the optimal resource option over the next decade. The remaining technical land-based wind potential on O'ahu is selected in year 2027 because of its high capacity factor and low assumed resource cost per kWh of renewable energy. Starting in year 2030, depending on the load scenario, varying amounts of solar paired with storage (hybrid solar) are built and reach the maximum solar land potential in the later years of the planning horizon. A large tranche of hybrid solar that resides in the lower-cost transmission renewable energy zones is selected in 2030 – in the Base scenario, nearly 1,600 MW of hybrid solar is selected, with the majority built on land with a slope greater than 15%. Of that 1,600 MW, 958 MW is located on land with less than 15% slope. The resource mix also includes renewable firm generation sources, powered by renewable fuels, that are critical to ensuring grid reliability when solar, wind and storage resources have lower production. Firm generation additions are generally timed slightly ahead of the removal of fossil-fuel generation to maintain generation reliability and are operated primarily as stand-by generation during periods of low renewables. In total, less renewable firm generation is being added than the amount of fossil generation that is deactivated because future capacity needs are increasingly met through the capacity contributions of other renewable resources such as wind and solar. The pace and quantity of these renewable resources will depend on customer trends, the way residential and commercial customers choose to consume energy over the coming years, including the number of electric vehicles on the road, the time of day the vehicles are charged, the amount of rooftop solar and battery energy storage customers install, and the energy efficiency measures that are adopted.

In a future where land is limited to develop renewable energy projects, more renewable firm generation sources will be needed. In this scenario, no new land-based wind or biomass projects are allowed to be selected and grid-scale solar is limited to an additional 270 MW. All 270 MW of grid-scale hybrid solar is built and greater amounts of firm generation is needed compared to the Base scenario. Over the longer term, offshore wind becomes an important resource in achieving 100% renewable energy along with distributed solar.

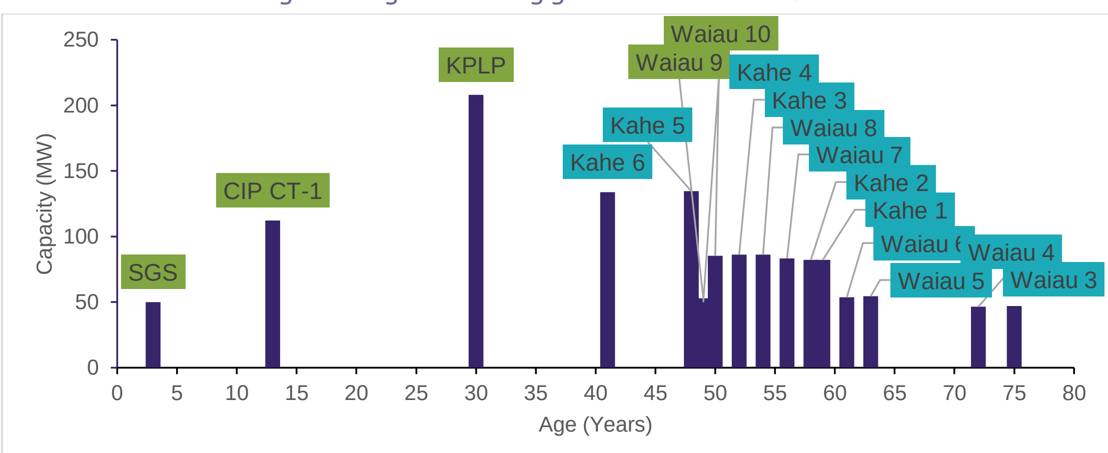
Resource Adequacy

Hawaiian Electric performed an extensive reliability analysis, guided by the reliability objectives that were prioritized by the IGP stakeholder council, a wide-ranging group representing community, government, environmental and business interests. Regular council meetings and feedback ensure stakeholder input and engagement throughout the IGP process. The stakeholder council's top three reliability objectives are: Evaluating the cost of different levels of reliability, generation resource diversity and planning reliability for extreme events. The stakeholder council had agreed that the utility should provide steady, adequate and generally affordable energy to customers in most circumstances.

In tandem with the stakeholder council's reliability objectives, reliability analyses found that significant amount of DER and DR resources (incremental 2030 customer resource additions relative to 2021 levels include 145 MW / 1,014 GWh of energy efficiency, 29 MW / 183 GWh of electric vehicles, and 253 MW / 423 GWh of private rooftop solar), between 270 MW and 1,600 MW grid-scale renewable resources, and 300-500 MW firm renewable generation by 2029 and another 200 MW by 2033 provides the optimal portfolio of resources to assure a reliable system and mitigate reliability risks in the near term. The combination of these resources also provide other benefits in modernizing the generation system such as the ability to quickly start up, ramp up and respond to fluctuations in wind and solar resources. The total near-term addition of 500-700 MW of renewable firm generation could potentially facilitate the removal or deactivation of 930 MW of utility and independent power producer (IPP) fossil-fuel generation.

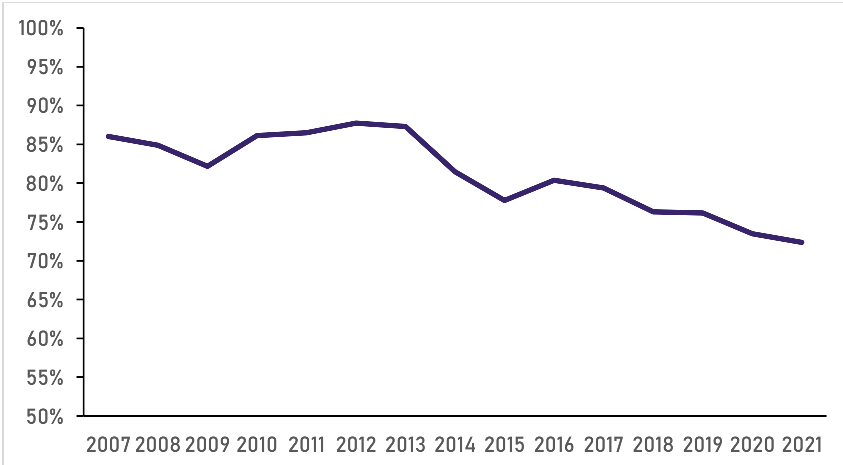
Reliability risks have been increasing over the past decade. Figure 1 illustrates the aging generation fleet that has served O'ahu residents over the past 70 years. These units are in urgent need of replacement, as they are currently being operated beyond their intended lifespan.

Figure 1. Age of existing generation fleet on O'ahu



But as shown in Figure 1 and Figure 2, old age coupled with higher stress operation since the onset of variable renewable energy has caused the generation fleet to become increasingly unreliable. The fleet needs to be retooled and modernized with newer, cleaner forms of firm energy.

Figure 2. Historical availability of Hawaiian Electric's generation fleet



The typical North America reliability guidelines for loss of load expectation (LOLE) are 0.1 days per year. The Australian Energy Market Operator uses reliability criteria that limits annual expected unserved energy (EUE) to 0.002% or less. These metrics provide a useful frame of reference when evaluating the LOLE and EUE of resource plans that consider different additions of variable renewables and firm generation resources. More stringent reliability guidelines may be warranted to address generation resilience on isolated island grids as high-impact, low frequency events increase in frequency.

In assessing system reliability through 2030, the analyses found that:

- Forced outages (and increasing unavailability of fossil-fuel generators) is a principal driver of reliability, especially when considering more recent trends in generator unit availability.
- 200 – 400 MW of new flexible firm generation alongside 270 – 1,600 MW of new hybrid solar in 2029 results in LOLE of 0.01 – 0.08 days per year and EUE of 0.01 – 0.09 GWh per year, indicating compliance with established resource adequacy standards used by other jurisdictions.
- Under a high load scenario that includes higher levels of electric vehicle (EV) growth that is consistent with state decarbonization policy, more than 400 MW of new firm generation is needed to achieve resource adequacy.
- While adding 1,600 MW of hybrid solar in 2029 improves reliability, 175 – 200 MW of firm generation is still needed to meet reliability standards.
- All resources considered in the resource adequacy analyses contribute to the reliability of the system. These include supply side resources like firm thermal generators, short and long duration energy storage, land-based wind, offshore wind, and hybrid solar as well as demand-side resources like distributed PV and energy efficiency. A diverse resource portfolio is important when planning for the future grid to avoid over-reliance on any one resource to meet resource adequacy.

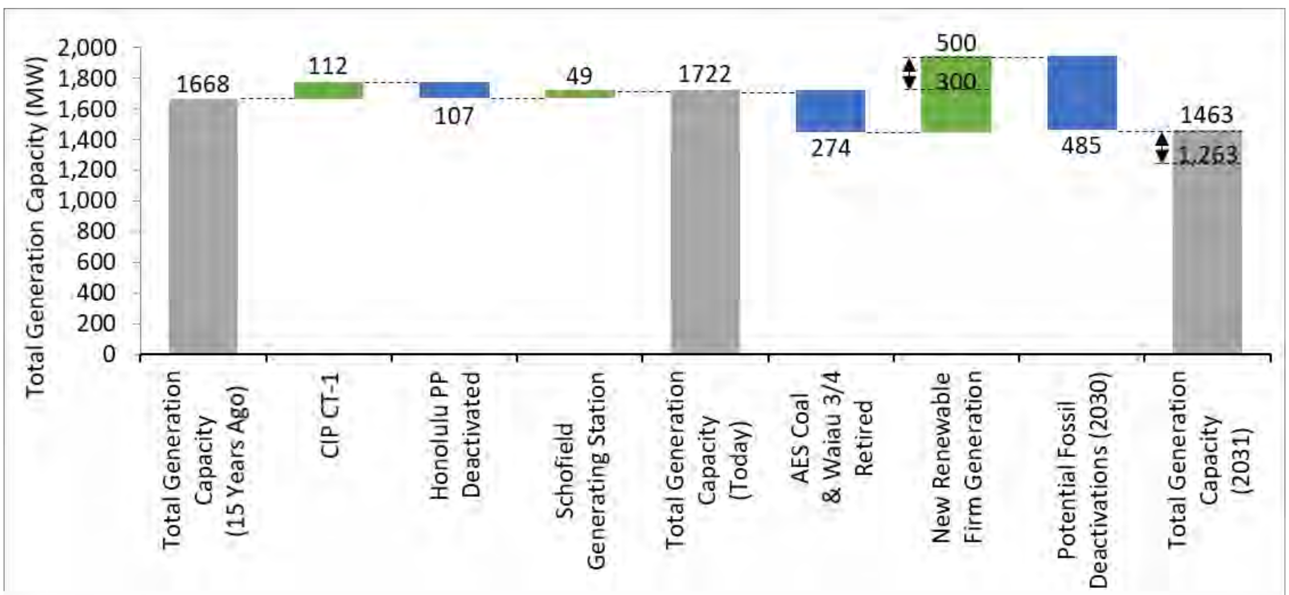
Hawaiian Electric conducted a thorough review of a probabilistic resource adequacy analysis that evaluated recent trends in generation outages and low and high amounts of future hybrid solar. This review found that 300 MW by 2029 and another 200 MW by 2033 is a minumum starting amount of new firm renewable generation that may improve reliability to an acceptable range of 0.10 days per year LOLE or better and limits EUE to 0.002%. However, a higher amount of firm generation in the range of 400 or 500 MW by 2029 could be needed to account for several future risks and uncertainties. These risks include a Land Constrained scenario where lower amounts of hybrid solar and no future land-based wind are added, higher loads, remaining fossil-fuel generation fleet further declining in performance, or where environmental concerns or lack of spare parts may hasten the retirement of existing generators.

Renewable dispatchable generation in combination with renewable firm generation is needed now to enable a reliable decarbonized electric economy

The 300 MW to 500 MW renewable firm generation by 2029 target accomplishes the reliability objectives set out by the stakeholder council and is based on rigorous technical analyses as described in this report. While a target of 500 MW of renewable firm generation may be interpreted as acquiring "excess" capacity in certain future scenarios, decarbonization efforts in other sectors of the economy is expected to lead to rapid load growth, such as in the high electrification load scenario. The conventional tendency is to procure the "just right" and "just in time" amount of capacity that meets near-term needs. ***However, the uncertainty surrounding the rapid transformation to a decarbonized economy through electrification, climate change impacts, significant shifts in the energy resource mix and customer adoption of new technology warrants a strategic shift in electric system reliability and resilience planning, one that positions Hawaiian Electric to rapidly respond to a rapidly changing environment.***

Hawaiian Electric has planned for this transition over the past 15 years and is now entering a new phase of that transition with the integration of new hybrid solar facilities. With the new hybrid solar projects acquired through recent procurements and additional resources expected in future procurement, significant fossil-fuel capacity could be deactivated, conditioned upon new renewable firm resources coming online, as shown in Figure 3.

Figure 3. Projected firm generation capacity timeline



The supply of electricity in the next few years and over the next 30 years will be heavily dependent on least-cost, weather-dependent resources that can contribute to traditional reliability needs and reduce reliance on firm fossil-fuel generation. However, overreliance on weather-dependent resources and battery energy storage will not provide the reliability (and resilience) needed to withstand severe weather periods or natural disasters that could damage grid-scale solar, wind or private rooftop solar systems. Renewable firm generation will diversify the energy portfolio and create a more resilient generation system by providing energy when other resources may be unavailable. As customers become increasingly reliant upon electricity through the electrification of transportation and buildings, system reliability and resilience must be increased. The 300-500 MW of new firm capacity by 2029 and an additional 200 MW of new firm capacity by 2033 will reduce reliability and resilience risks against a range of futures that were analyzed. For example, 700 MW of new firm generation would provide some assurance of maintaining system reliability if load rapidly grows over the next decade due to electric vehicle growth as forecasted in the high load scenario (more firm generation will likely be needed in this scenario). In the Land Constrained scenario where only a limited amount of land is available for future solar development, new firm units will be used more often to ensure the load can be served.

In summary, procuring at least 300 MW and up to 500 MW by 2029 and an additional 200 MW by 2033 of renewable firm generation is a least-regrets target to maintain and improve reliability against a range of uncertain futures.

Acquisition of a diverse and reliable resource portfolio

While all-source and technology-neutral procurements are pursued whenever possible, such procurement may not yield the most diverse and resilient portfolio in this case. Without a specific target for renewable firm generation, a technology-neutral procurement will likely yield more hybrid solar projects as recent procurements suggest, resources which are indeed needed to achieve decarbonization goals. However, to encourage diversification, reduce reliability risks and increase resilience of the generation system, a procurement with a specific renewable firm generation target is warranted. As the reliability analysis demonstrated (Section 6.5), a significant amount of additional hybrid solar without new firm generation would not be sufficient to meet a targeted reliability range; thus, firm generation is needed.

The acquisition of additional low-cost solar, wind and energy storage resources alongside renewable firm generation will reduce fossil-fuel usage. To that end, and consistent with the findings of this report, procuring renewable dispatchable generation alongside firm generation will allow renewable firm generation to operate fewer hours per year but play a critical role in operating during periods of poor sun or wind conditions, providing quick-starting capability and offline reserves during contingency events.

Procuring firm renewable generation also addresses the increasing reliability risk of an aging, inflexible generation fleet with flexible resources to facilitate the integration of more wind, solar and energy storage resources. By necessity, the existing fossil-fuel generation fleet is being operated at lower minimum loads and cycling more than it was designed to do. As more hybrid solar projects are integrated over the next few years, these inflexible steam generation units will be strained under increasingly variable operations. Operating the 55- to 75-year-old fleet in this manner only accelerates the aging process, which has led to and will continue to cause increasing rates of forced outages and more deration of firm capacity on a daily basis. These reliability risks must be urgently addressed—this is foundational to achieving the state's decarbonization and renewable energy goals.

Hawaiian Electric is once again at the forefront of the industry through its recent procurements to integrate hybrid solar plants at unprecedented levels relative to the size of the system. There will be a lot to learn from operating these hybrid plants over the next five to 10 years; particularly how batteries are best used to improve reliability and resilience. There are many issues that remain (i.e., pace of electrification, availability of existing firm generation, land constraints, community acceptance, performance of grid-forming inverters for stability, supply chain issues, among others), and we must be prepared for increasing risks throughout the industry.

Hawaiian Electric has made significant progress in integrating wind, solar and energy storage resources and more is expected. But this cannot be done at the expense of reliability, which will have far greater economic and societal consequences for the state. If fossil-fueled firm generation is not replaced with new flexible firm generation, there will be a limited ability to integrate more low-cost intermittent renewable energy in the future, resulting in an increased burden on underserved communities.

For example, new flexible generators have lower minimum operating points and can quickly ramp up and down, start and stop multiple times a day. New generators also have significantly higher availability and reliability. These benefits allow more low-cost renewable energy to be utilized at much higher levels than if the current fleet of inflexible fossil-fuel generation remains in service. Higher utilization of low-cost renewable energy will mean a lower electric bill burden on customers; disproportionately

Near-Term Action Plan

- Continue to displace fossil-fuel through acquisition of low cost, low carbon renewable energy, starting with 544 GWh through the Stage 3 RFP in Docket No. 2017-0352
- Continue to pursue customer adoption of DER through new programs and advanced rate design, consistent with the outcomes of the DER Docket No. 2019-0323
- Pursue generation modernization as soon as practicable to improve operational flexibility and mitigate present reliability risks. Firm renewable generation needs include 300-500 MW of in 2029, and another 200 MW in the 2033 timeframe, starting with the Stage 3 RFP in Docket No. 2017-0352
- Pursue development of renewable energy zones to facilitate interconnection of additional renewable energy
- Consider procurement of energy efficiency to accelerate adoption in amounts up to the forecasted target to reduce supply side needs.
- Continue to pursue managed EV charging programs, time-of-use rates, DER, and energy efficiency.
- Incorporate system security and system stability analyses as part of IGP, which may yield additional resource needs to mitigate risks associated with a high-renewable energy system.
- Pursue procurement(s) as part of the IGP solution sourcing process to determine market for long lead renewable resources such as offshore wind and renewable energy zones to increase resource diversity and mitigate land use risks.

affecting customers that do not have access to or the means to invest in technologies to offset their own electricity usage. Continuation of the current fossil-fuel generation fleet will mean increased likelihood of outages and volatile energy prices. Ultimately, generation modernization today keeps the state on track to achieving its policy goals which include 100% renewable energy, a balanced portfolio of resources, cost-effective electricity, decarbonization of transportation and other sectors, and resilience against extreme weather events.

2 INTRODUCTION

The 2021 international summit on climate change made clear that the actions we take this decade will determine whether humanity can slow or stop the warming of the planet. To support this global effort, Hawaiian Electric announced a bold Climate Change Action Plan centered on reducing carbon emissions by as much as 70% by 2030 compared to 2005 levels and reaching net-zero carbon emissions by 2045. Reducing carbon emissions by more than two-thirds over this decade will be a stretch. We know it's achievable and if everyone pitches in, we'll create a cost-effective, sustainable and resilient energy system for future generations. This commitment by Hawaiian Electric is a significant down payment on the economy-wide reduction the State of Hawaiʻi will need to achieve to align with the U.S. commitment to reduce carbon emissions by at least 50%.

In setting out pathways to achieve those goals, Hawaiian Electric conducted this grid needs assessment – a living roadmap intended to guide efforts by the company, customers, stakeholders, project partners and communities to realize deep decarbonization across the economy with an emphasis in the electric sector. The integrated grid planning (IGP) process as well as other energy efforts will continue to build and refine "what is needed" to eventually meet the state's goal of net negative carbon emissions by 2045.

To guide the development of the grid needs assessment, Hawaiian Electric leveraged the IGP process and incorporated feedback from the IGP stakeholder council, technical advisory panel and stakeholder technical working group (STWG). The process, methods, criteria, inputs and assumptions and feedback incorporated are documented in Hawaiian Electric's *August 2021 Inputs and Assumptions* review point filing, its subsequently approved *March 2022 Inputs and Assumptions* filing and its *November 2021 Grid Needs Assessment and Solution Evaluation Methodology* review point. As a result, the inputs, assumptions and methodologies used in this report are among the most transparent planning processes in the industry, with stakeholder and expert recommendations incorporated along the way.

The stakeholder council's role in advising Hawaiian Electric has been instrumental in guiding the grid needs assessment. The stakeholder council has focused on three key areas: community engagement, reliability and resilience. Key highlights in these three areas are discussed below, and the incorporation of the stakeholder council's feedback is noted throughout this report.

Community Engagement

The stakeholder council made the following recommendations to improve community engagement in the IGP and procurement processes:

- There are three "branches" that need public participation, input and guidance: Hawaiian Electric, the Public Utilities Commission (PUC) and developers. Public participation is also needed from other key stakeholders, such as the Hawaiʻi State Energy Office.
- Hawaiian Electric should raise the "floor" of stakeholder engagement: defining and raising the bar for minimum requirements of successful engagement.
- Customization is key, as different communities have different interests. It's critical to listen and understand each community's needs and objectives. For example, the Kunia community is concerned about agriculture. The North Shore community may be interested in education and job creation for the community related to the renewable project.

- The PUC has a role to play in soliciting community input. Look for ways for the PUC to be more open and accessible to the public and provide public notice of dockets outside of the current process, such as through news releases. The PUC should solicit input on RFPs throughout the RFP process rather than only at the end when projects are already selected.
- Be more proactive in soliciting input during RFP development. Reach community members via newspapers, website, social media, neighborhood newsletters, etc. Broaden the type of stakeholders who provide input beyond just energy “insiders” who are involved in the industry on a day-to-day basis.
- Consider “co-design” of concepts in RFP development similar to what is being done on Molokaʻi. Start the engagement process in Step 1, not Step 5.
- Identify available sites for development and work with neighborhoods and communities on siting projects there prior to RFP issuance.
- Better demonstrate to communities how feedback is being taken into account.

Specific Recommendations and Changes Hawaiian Electric Proposes to Make to the IGP and Procurement Process

Across many different initiatives, Hawaiian Electric has heard the desire of communities to play a more engaged role early in the renewable energy development process. Hawaiian Electric continues to engage communities around the islands as it develops RFPs and identifies future grid needs, while leveraging the various tools for communication that incorporate many of the concepts put forward by the stakeholder council. Building upon the outreach to stakeholders and communities in developing recent RFPs, Hawaiian Electric will continue to listen, learn and work with communities throughout the process of developing the next round of RFPs on Oʻahu and other islands.

What outreach tools will Hawaiian Electric use?

Over the next year, we will use virtual and in-person outreach tools to share information with the public and gather input. These tools include:

Online participation site
Hub for up-to-date information and community feedback, with interactive maps, comment form and survey questions.

Briefings with community organizations
Offering presentations at existing community meetings, either virtually or in person.

Community talk stories
Smaller, informal in-person or virtual conversations with community members to share information and discuss Hawaiʻi’s energy future.

Public meetings
Broad public meetings with presentations, Q&A sessions, and opportunities to share input.

We will tailor our outreach tools and strategies to meet the unique needs of each island.

One key way Hawaiian Electric proposes to incorporate stakeholder council recommendations and past community feedback is to expand community engagement requirements for prospective projects by further specifying requirements for community engagement with more detailed guidance and by adding a requirement that developers provide a benefits package for the surrounding and affected communities.

Hawaiian Electric proposed to require project developers to commit to financial community benefits. Developers will be required to set aside at least $3,000 per MW (of their proposed project) per year for community benefits. These funds would be donated for actions and/or programs aimed at addressing specific needs identified by the host community, or to a 501(c)(3) not-for-profit community-based organization(s) to directly address host community-identified needs. The developers would provide a documented community benefits package highlighting the distribution of funds for Hawaiian Electric’s review. This document will be made public on each project’s website and demonstrate how funds will directly address needs in the host community.

The community benefits package would also include documentation of each project developer’s community consultation and input collection process to define community needs, along with actions and programs aimed at addressing those needs. Preference would be given to projects that commit to setting aside a larger amount or commit to providing other benefits (including but not limited to creating local jobs, payment of prevailing wages or improving community infrastructure).

In addition, Hawaiian Electric has also included the following modifications to the procurement process in response to community feedback:

- Higher scoring to project proposals that are proposed on land zoned commercial, industrial, land with greater impervious cover, or reclaimed land;
- Procedural improvements were made to further ensure the protection and preservation of cultural resources;
- Prioritization of local labor and prevailing wage for proposed projects; and
- Additional requirements for developers to provide monthly updates to the community prior to and throughout the construction process.

Reliability

The stakeholder council discussed generation reliability and considerations in forward-looking planning. The council developed a core goal of reliability: to ensure a steady, adequate and generally affordable energy to customers, almost all of the time. Through a robust discussion, the stakeholder council prioritized their top three reliability objectives in support of the core goal:

- Evaluate cost of higher levels of reliability
- Diversify generation resources
- Plan for extreme events

Based on those objectives, the stakeholder council considered various capabilities and strategies to meet those objectives. Common themes included:

- Reliability for Tier 1 customers (i.e., the most critical customers defined in the Resilience Working Group Report and shown in Figure 4) should be a priority
- An evaluation of reliability contributions of different generation technologies (i.e., solar, wind, energy storage, firm generation, etc.)
- Define and clarify terminology—for example, firm generation, non-firm generation, hybrid solutions. Firm generation is not perfect and could also be affected by fuel supply and forced outages.
- The role of microgrids and how they can support grid reliability and resilience.
- Customer solutions for reliability
- Harden the transmission and distribution (T&D) system—for example, hardening of poles, wires and other critical equipment
- Investigate future technologies like green hydrogen

Some of these capabilities and objectives are also grid resilience considerations (i.e., the role of microgrids, T&D hardening and planning for extreme events), while others have been brought to the technical advisory panel (TAP) for recommendations. Hawaiian Electric addresses or incorporates these objectives and capabilities within this report. For example, the reliability contributions of different generation technologies and the subject and definition of firm generation are issues that have been extensively discussed with the TAP and addressed through the resource adequacy analyses provided in Section 6. A discussion of customer solutions for reliability is discussed in Section 6.1. Planning reliability for extreme events is intertwined with resilience; however, a discussion of inclusion of extreme events in reliability planning is discussed in Section 6.5.10.

Resilience

The IGP resilience working group and stakeholder council provided recommendations and considerations for incorporating resilience into grid planning. The working group built consensus on a definition of resilience and adopted the commission's definition in the performance-based regulation docket, "Resilience is the ability of a system or its components to adapt to changing conditions and withstand and rapidly recover from disruptions." For the grid, this means the ability to anticipate, absorb, adapt to, and rapidly recover from a catastrophic event. Stakeholders defined the following objectives for resilience:

- Reduce the likelihood of power outages during a severe event
- Reduce the severity and duration of any outages that do occur during and after a severe event
- Reduce restoration and recovery times following a severe event
- Return critical infrastructure customers' power rapidly to enable mutual support and recovery during an emergency
- Return all customers within appropriate times
- Limit environmental impacts of a severe event

The following threat scenarios were prioritized by the working group to guide the IGP process and other resilience initiatives, and by key customers and critical infrastructure partners in developing resilience preparations.

- Hurricane/floods/high wind events
- Tsunamis and earthquakes
- Wildfire
- Physical and cyber attack
- Volcano (Hawaii Island)

As shown in the figure below, the working group recommended three different customer tiers to prioritize for enhancing resilience. The identification of customer groups represents stakeholders' views of the prioritization of customers with the greatest need to be returned to service quickly. These priorities should also be coordinated with other agencies for alignment on restoration priorities.

Figure 4. Resilience working group recommended customer classifications by tier

Tier 1	Tier 2	Tier 3
• Military • Telecommunications • Hospitals and critical healthcare • Water and wastewater • Emergency management and first responders	• Transportation • Hospitality • Banking and finance	• Remaining customers

Since 2015, the Governor has issued at least 15 different emergency proclamations relating to hurricanes, tropical storms, flooding, landslides, wildfire, and lava events. A common theme that emerged during the working group and stakeholder council discussions raised that resilience should be considered in reliability planning because it's a matter of "when, not if" a weather-related event threatens the reliability of the grid. A lot more work is needed within the resilience area; however, in Section 6, initial elements of resilience are being incorporated within the reliability analysis consistent with the recommendations stated herein. However, Hawaiian Electric expects to continue to refine its resilience analysis as more discussions occur and additional information becomes available.

Guiding Principles

Hawaiʻi is at a much different place in its grid transformation and decarbonization efforts than any other state. Over the next few years, Oʻahu, Hawaiʻi Island, and Maui County are collectively expected to reach 50% renewable generation with a combination of wind, solar, geothermal, hydro, biomass/waste-to-energy, battery energy storage and private rooftop solar. This means the islands will rely on a much higher percentage of variable resources than other states to contribute to ensuring a reliable energy system. It is essential that integrated grid planning is considered across all aspects of the community and grid including distribution, transmission and generation resources. Additionally, customers must appropriately benefit from costs incurred to advance the state's policies and related investments. Hawaiian Electric relies upon a set of renewable energy planning principles in developing its roadmap and action plan.

Guiding Principles

Renewable energy is the first option. We are pursuing cost-effective renewable resource opportunities that reduce carbon emissions and stabilize customer bills. Getting off imported fossil-fuels removes Hawaiʻi from the volatility of world energy markets and gives future generations a tremendous advantage. It can also create a clean energy research and development industry for our state.

The energy transformation must include everyone. Electricity is essential. Our plans, as well as public policy, should ensure access to affordable electricity, with special consideration given to low-to-moderate-income households. Meaningful community participation must be a key element of renewable project planning.

The lights have to stay on. Reliability and resilience of service and quality of power is vital for our economy, for our national security, and for critical societal infrastructure. Our customers expect it, deserve it and pay for it. Our plans must maintain or enhance the resilience of our isolated island grids by relying on a mix of resources and technologies.

Today's decisions must be open to tomorrow's breakthroughs. Our plans keep the door open to developments in the rapidly evolving energy space. We must be able to easily accept new, emerging, and breakthrough technologies that are cost-effective and efficient when they become commercially viable.

The power grid needs to be modernized. Energy distribution is rapidly moving to the digital age. We are reinventing our grid to facilitate a decarbonized energy portfolio and to enable technologies such as demand response, dynamic pricing, aggregation and electrification of transportation.

Our plans must address climate change. Our Climate Change Action Plan has set a goal to reduce carbon emissions from power generation 70% by 2030 compared with 2005 levels. Our resilience strategy aims to minimize the impacts of climate change — rising sea levels, coastal erosion, increased temperatures and extreme weather events — on the energy system.

There's no perfect choice. No single energy source or technology can achieve our clean energy goals. Every choice has an impact, whether it's physical or financial. While we can mitigate those impacts, attaining our clean energy goals has major implications for our land and natural resources, our economy and our communities. We seek to make the best choices by engaging with community members, regulators, policy makers and other stakeholders.

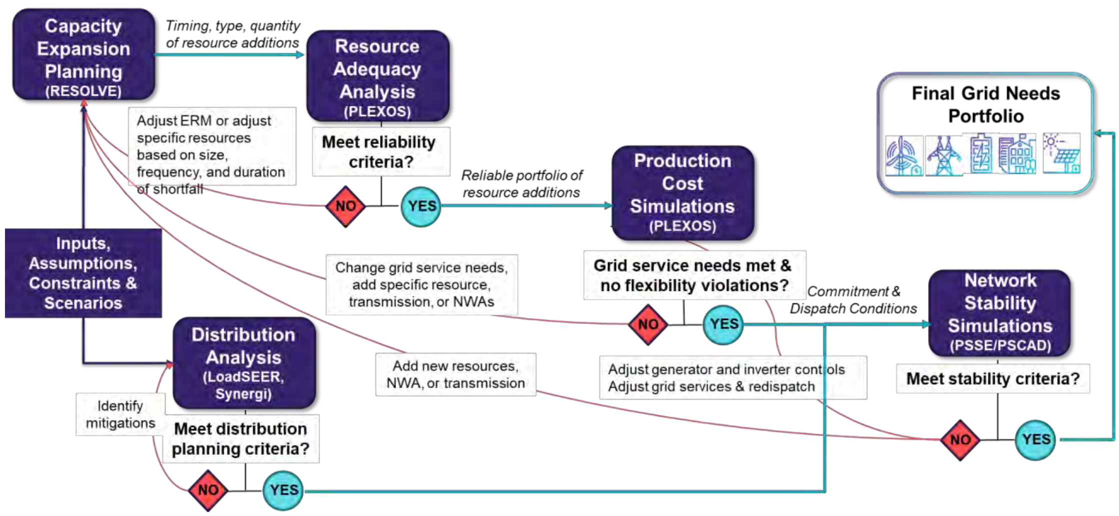
This report is organized as follows:

- Sections 3, 4 and 5 describe the methodology in assessing grid needs, the inputs and assumptions used in the various technical analyses and the scenarios that were analyzed in forming the near-term roadmap and next steps.
- Section 6 describes the results of the grid needs analysis. The majority of the report focuses on near-term reliability needs within the context of long-term resource plans over a number of potential future scenarios.
- Section 7 describes production cost simulations and operations under the procurement resource plan, showing the simulated dispatch of resources on the system.
- Section 8 describes the near-term next steps and action plan.

3 METHODOLOGY

Hawaiian Electric used the analytical framework developed in the IGP process to identify the grid needs for near-term solutions sourcing. As shown in Figure 5, multiple tools were used to determine the grid needs.

Figure 5. Grid Needs Assessment methodology



This grid needs assessment (GNA) focuses on the first three steps of the GNA methodology to assess near-term capacity expansion planning, resource adequacy and production cost simulations based on the March 31, 2022 and August 2021 IGP Inputs and Assumptions as described in Section 4. The methodology to identify grid needs is described in Hawaiian Electric's November 2021 Grid Needs Assessment & Solution Evaluation Methodology review point (GNA Methodology Report). The IGP process ongoing in Docket No. 2018-0165 will build upon this GNA, including the approved *IGP Inputs and Assumptions* filed on March 31, 2022, and the remaining analytical steps – network stability and distribution analysis.

Grid Needs means the specific grid services (including but not limited to capacity, energy and ancillary services) identified in the grid needs assessment, including transmission and distribution system needs that may be addressed through a Non-Wires Alternative.

RESOLVE was used to provide directional grid needs detailing the optimal type, quantity and timing of resource additions across various scenarios based on a range of constraints such as pricing (capital cost, fixed cost, variable cost, etc.), operational characteristics (power output, ramp rate, heat rate, etc.) and services offered (provide regulation, meet RPS, etc.). An energy reserve margin analysis was performed in PLEXOS to check the reliability of the various scenarios under study alongside a detailed probabilistic resource adequacy endorsed by the TAP. Finally, a production cost simulation was also performed in PLEXOS to provide a more accurate hourly dispatch of the generating fleet.

3.1 Capacity Expansion (RESOLVE)

The grid needs assessment uses the planning assumptions from the Company's *Inputs and Assumptions* filings summarized in Section 4 to determine a baseline, or "Base" portfolio of grid needs, the Low Load and High Load bookend scenarios and the Land Constrained scenario where the potential to develop future renewable projects is constrained based on limited community approval for new renewable energy development. The portfolios were developed using the RESOLVE and PLEXOS models to identify and verify the grid needs through 2035. The primary objective of this phase of the process was to identify the optimal mix of proxy resources that are built to represent the system's grid needs. RESOLVE is intended to provide directional guidance as to the optimal mix of resources; it is not intended to be a prescriptive pathway that must be strictly followed during solution sourcing activities.

3.2 Resource Adequacy (PLEXOS)

The Resource Adequacy step includes a separate energy reserve margin (ERM) analysis in PLEXOS of each scenario plan developed during the capacity expansion modeling step to determine capacity reliability needs. Additional capacity needs were informed by the unserved energy observed when the net load, plus a 30% margin, was not met by existing resources. The ERM methodology is further described in the GNA Methodology Report, Exhibit 1, Appendix C. Iterations were completed to evaluate varying amounts of firm generation resources to meet the energy reserve margin guideline.

The resource adequacy step also includes a probabilistic analysis consistent with industry best practices, including recommendations Hawaiian Electric adopted from the TAP. The probabilistic analyses evaluate the reliability of the system using five weather years and 50 randomized generator outages for a total of 250 iterations; the results are then used to calculate various reliability metrics including loss of load expectation (LOLE), loss of load events (LOLEv), loss of load hours (LOLH) and expected unserved energy (EUE) to assess reliability.

3.3 Production Cost Simulations (PLEXOS)

The resource plans optimized in RESOLVE and adjusted to meet resource adequacy were then evaluated in PLEXOS, by running an hourly production cost simulation, to verify system operations and dispatch of resources. This provides insight into how the new resources will be operated and dispatched in future years. The system costs of each plan are based on the sales forecast, fuel price forecast and resource cost assumptions described in Section 4. More accurate costs of long-term plans will be developed as part of the solution sourcing process when actual market solutions are proposed with current market pricing.

4 KEY INPUTS TO GRID NEEDS ANALYSIS

The inputs used in this analysis are briefly described below.

4.1 Sales Forecast

Hawaiian Electric utilized the sales forecast in its *August 2021 IGP Inputs and Assumptions* filing. This sales forecast includes updates to its electric vehicle forecast (including the managed and unmanaged charging system profile), customer solar and battery storage forecast and the addition of a time-of-use layer representing non-DER and EV customer participation.

While the inputs and assumptions were not approved by the PUC until modifications were filed on March 31, 2022, the changes to the forecast layers are not considered significant and contained well within the load bookends that were modeled.

4.2 Fuel Price Forecast

Hawaiian Electric utilized the 2021 fuel price forecast in the *March 2022 IGP Inputs and Assumptions* filing approved by the PUC on March 31, 2022. This fuel price forecast was based on the Brent forecast provided by the Energy Information Administration Annual Energy Outlook 2021 (EIA AEO).

4.3 Future Resource Options

RESOLVE is given a variety of resource options to choose from, as shown below in Figure 6, during the development of the capacity expansion plans. Firm resources consist of biomass, combined cycle (CC), combustion turbine (CT), and internal combustion engines (ICE). In this analysis, these resources are assumed to be operating on renewable fuels, such as biodiesel, but a sensitivity analysis was performed where these resources were assumed to be operated on fossil-fuel. Storage includes short and long duration standalone energy storage as well as pumped storage hydro that are grid charge capable resources. Wind resources consist of both land-based and offshore wind. Solar resources consist of both standalone solar PV, hybrid solar (i.e., PV paired with energy storage) where RESOLVE can optimize the storage duration, and residential PV paired with 2 hour distributed BESS that is provided via a DER aggregator. Paired storage must be charged by the source they are paired with and are not grid charge capable.

In addition to being modeled as available candidate resources in RESOLVE, the probabilistic resource adequacy analyses explicitly considered the addition of several of these resources to evaluate their impact to reliability.

- Combustion Turbines – Section 6.5.2 and 6.5.3
- Paired PV+BESS – Section 6.5.1 and 6.5.3
- 12 Hour Duration Energy Storage (Proxy for Pumped Storage Hydro) – Section 6.5.4
- 2 Hour Duration Energy Storage (Proxy for Demand Response) – Section 6.5.8
- Land-based Wind – Section 6.5.1 and 6.5.3
- Offshore Wind – Section 6.5.9

Figure 6. Future resource options for RESOLVE to select

Firm	Storage	Wind	Solar	Distributed Energy Resources (DER)
Steam/Biomass	Standalone Battery Energy Storage System (BESS)	Land-Based Wind	Standalone Solar (PV)	Aggregated Distributed Energy Resources (Distributed Paired Solar)
Combined Cycle (CC)	Pumped Storage Hydro (PSH)	Offshore Wind	Hybrid Solar (Paired PV)	
Combustion Turbine (CT)				
Internal Combustion Engine (ICE)				

4.4 Resource Cost Forecast

The resource cost forecast used to develop the resource plans provided in this analysis is consistent with the *March 2022 Inputs and Assumptions* filing with the exception that we did not apply the cost adders for development of renewables on higher sloped land. The cost adders were not available at the time of this analysis, which was mostly conducted before March 2022, but will be included in future analyses.

4.5 Regulating Reserve Requirement

The regulating reserve requirements were based on the methodology described in Hawaiian Electric's November 5, 2021, *GNA Methodology Report*. This analysis included both the 1-minute and 30-minute regulating reserve requirements.

4.6 Hourly Dependable Capacity for Energy Reserve Margin

The hourly dependable capacity (HDC) for variable renewables was based on the 1-sigma calculation as described in Hawaiian Electric's November 5, 2021, GNA Methodology Report. Hawaiian Electric has since adopted the 80th percentile dependable capacity methodology for renewable resources; however, at the time of this analysis such discussions were still on-going with the technical advisory panel. The use of 1-sigma, however, is substantially similar to the 80th percentile, as discussed at a January 20, 2022 TAP Meeting. Therefore, Hawaiian Electric expects the impact using the 1-sigma approach instead of the 80th percentile to be negligible.

4.7 Variable Renewable Resource Potential

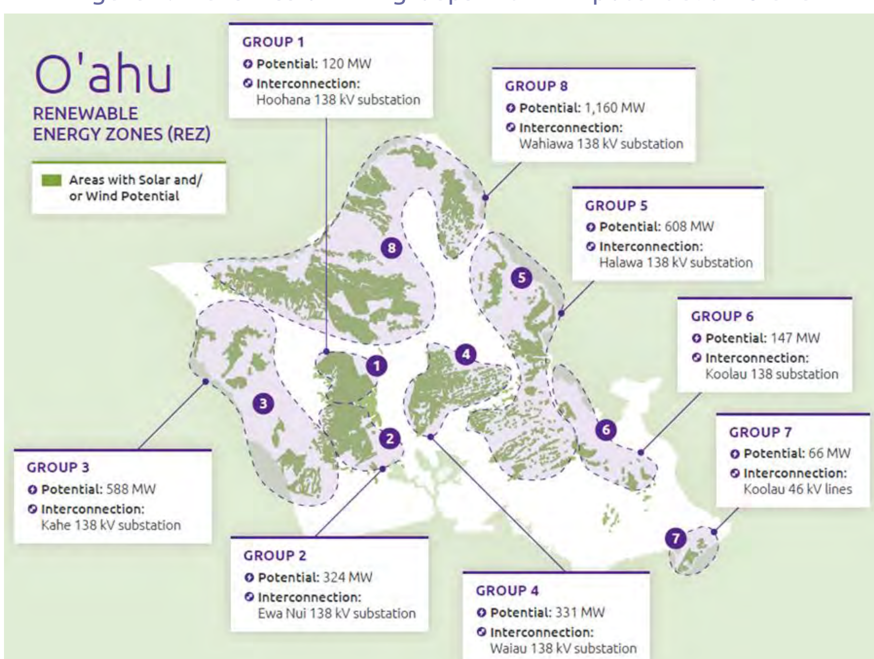
The developable potential for variable renewables was based on the resource potential study conducted by the National Renewable Energy Laboratory (NREL). Based on stakeholder feedback, NREL revised their study to include additional scenarios described in their July 30, 2021 *Assessment of Wind and Photovoltaic Technical Potential for the Hawaiian Electric Company*.

Consistent with the approved *March 2022 Inputs and Assumptions*, the "Alt-1" scenario developed in NREL's revised study was adopted to define the additional variable renewable capacity that could be selected in the RESOLVE model. A summary of the resource potential study was described in Hawaiian Electric's *March 2022 Inputs and Assumptions*. In this GNA, however, the solar and wind resource potential were not split by potential up to 15% sloped land and 30% sloped land. All potential capacity up to 30% sloped land was grouped by renewable energy zone, as described in the following section.

4.8 Renewable Energy Zone Enablement

Renewable energy zone (REZ) upgrades are composed of two costs: Transmission network expansion costs which are the transmission upgrades not associated with a particular REZ group but are required to support the flow of energy within the transmission system and REZ enablements which are the costs of new or upgraded transmission lines and new or expanded substations required to connect the transmission hub of each REZ group to the nearest transmission substation. The REZ enablement costs were included as part of the forecasted cost for new variable renewable resources to be selected by RESOLVE; however, no transmission network expansion costs were included. For further details on the REZ and associated enablement infrastructure, requirements and costs, see the [Hawaiian Electric Transmission REZ Study]() as part of Hawaiian Electric's *November 2021 GNA Methodology Report*.

Figure 7. Transmission REZ groups with MW potential on O'ahu



The groups identified in the REZ study were aggregated by similar REZ enablement cost for modeling in RESOLVE to model a reasonable number of candidate resource options.

- Group 1 in RESOLVE (510 MW) – Groups 1, 2 and 7 from the REZ study
- Group 2 in RESOLVE (1,674 MW) – Groups 3, 4, 5 and 6 from the REZ study

- Group 3 in RESOLVE (1,160 MW) – Group 8 from the REZ study

4.9 Planned Resources

The model assumes 2027 as the first-year resources can be placed into service. The resources assumed to be in-service prior to 2027 are shown in Figure 8.

Figure 8: Future resources assumed to be in service prior to the start of the planning horizon

Resource	PV (MW)	BESS (MW/MWh)
CBRE Phase 2 Small	30	0 / 0
CBRE Phase 2 RFP	150	0 / 0
Hoohana Solar 1	52	52 / 218
Mililani Solar 1	39	39 / 156
Waiawa Solar	36	36 / 144
AES West O'ahu Solar	12.5	12.5 / 50
Barbers Point Solar	15	15 / 60
Kupono Solar	42	42 / 168
Kupehau*	60	60/240
Mahi Solar*	120	120 / 480
Mountain View Solar	7	7 / 35
Waiawa Phase 2 Solar	30	30 / 240
Kapolei Energy Storage	N/A	185 / 565

*Note the Mahi and Kupehau Solar projects power purchase agreements with Hawaiian Electric have since been declared null and void. In the Land Constrained cases, it was assumed these two projects are operational by 2030 as part of the constrained resource potential. Later in this report, sensitivities around the Mahi and Kupehau Solar project are discussed.

4.10 Near-Term Conditional Fossil-Fuel Generation Removal from Service

Hawaiian Electric assumed that certain amounts of firm fossil-fuel generating capacity would not be available for dispatch for the purposes of identifying grid needs. Removing firm fossil-fuel generating capacity planning assumptions noted below does not imply that the Company will retire the amount of firm generation capacity in the years indicated. The actual removal of generation from service is conditioned upon several factors, including whether sufficient resources have been acquired and placed in service to provide replacement grid services, reliability and resilience considerations, among others.

- Remove 90 MW fossil-fuel generation in 2024
- Remove 110 MW fossil-fuel generation in 2027
- Remove 170 MW fossil-fuel generation in 2029
- Remove 170 MW fossil-fuel generation in 2033

Sensitivities were also modeled to evaluate a scenario where the amended and restated power purchase agreement (PPA) for the 208 MW Kalaeloa Partners (KPLP) combined-cycle facility is approved for a 10-15-year term. Following that term, KPLP's PPA is assumed to not be renewed and the services provided by KPLP would need to be replaced through repowering of KPLP or other resources.

5 SCENARIO ANALYSIS

Several scenarios were examined to identify a range of potential grid needs to develop the Stage 3 RFP targets. Other scenarios laid out in the March 2022 Inputs & Assumptions will be considered further in the IGP process.

- Base Scenario – Assumes the base set of IGP sales and fuel price forecasts, in-service of the Stage 1 and 2 RFPs, CBRE RFP and GSPA projects. Existing power purchase agreements are assumed to terminate at the end of their current contract term. New variable renewable resources are allowed to be built up to the NREL Alt-1 resource potential. Certain existing fossil-fuel generating units are assumed to no longer be dispatched as described in Section 4.10. This scenario represents a net load forecast incorporating the most likely scenario of customer technology adoption.
    - Existing power purchase agreements include AES Coal, Kalaeloa Renewable Energy Park, Kalaeloa Solar Power II, Kapolei Sustainable Energy Park, Kawailoa Solar, Lanikuhana Solar, Waianae Solar, Waiawa PV, West Loch Solar, Kahuku Wind Farm, Kawailoa Wind Farm, Na Pua Makani Wind Farm.
- Low Load Scenario – Assumes the set of IGP sales forecasts that reduce customer demand including the high distributed energy resource (DER), high energy efficiency (EE) and low electric vehicle (EV) forecasts. Together, these forecast layers provide a low load to bookend or bound future, plausible demand that Hawaiian Electric should plan to serve. Other planning assumptions follow the Base scenario.
- High Load Scenario – Assumes the set of IGP sales forecasts that increase customer demand including the low DER, low EE and high EV forecasts. Together, these forecast layers provide a high load to bookend or bound future, plausible demand that the Company should plan to serve. Other planning assumptions follow the Base Scenario.
- Land Constrained Scenario – There is a limited amount of available land on Oʻahu, and a significant percentage of that land is on the side of mountains or near communities. Reduced resource capacities in this scenario are based on stakeholder feedback and represent what the Company believes can be added before needing additional infrastructure for REZs that will require an extensive community engagement process. Using the Base case, future grid-scale solar was assumed to have a reduced resource potential capacity of 270 MW and offshore wind was assumed to have a potential capacity of 400 MW. Biomass and land-based wind are assumed to be unavailable due to land constraints to build new wind projects and harvest biomass supply from purpose-grown crops. Similar to the High Load and Low Load bookends, the Base and Land Constrained scenarios provide reference points for future developable resource potential.

Figure 9 provides the Base, Land Constrained, High Load and Low Load scenarios forecast assumptions for EE, DER, EV and time-of-use (TOU) load shapes associated with customers who do not have DER or EV.

Figure 9. Forecast assumptions for the Base, High Load and Low Load scenarios

Forecast Layer	Base & Land Constrained	High Load	Low Load
EE	Base	Low	High
DER	Base	Low	High
EV	Base	High	Low
EV Charging Shape	Managed	Unmanaged	Managed
Non-DER, Non-EV TOU	Base	Low	High

While the load forecast assumption for the Land Constrained scenario is the same as the Base scenario, the Land Constrained scenario is more limited in what resources can be built. Figure 10 shows the differences in renewable resource potential between the Land Constrained scenario and all other scenarios. It is important to note that in the Base scenario, of the 3,300 MW of solar power that can be developed, approximately 2,300 MW is expected to be on land with slopes greater than 15% but less than 30% and approximately 1,000 MW on land with slopes less than or equal to 15%.

Figure 10. Differences in renewable resource potential between the Land Constrained scenario and the Base, High Load and Low Load scenarios

Resource (MW)	Base High Load Low Load	Land Constrained
Solar	3,300	270
Land-Based Wind	164	0
Offshore Wind	600	400
Biomass	No Limit	0
Biofuel	No Limit	No Limit

6 RESOURCE GRID NEEDS ANALYSIS

The RESOLVE capacity expansion model was used to develop an optimized resource plan using the assumptions described for the Base, Land Constrained, Low Load and High Load scenarios. The results of the RESOLVE modeling were used to inform the variable renewable and storage additions assumed in subsequent analyses. Renewable firm resource additions were further analyzed through the resource adequacy analysis.

To verify that the reliability capacity needs were met using 30% Energy Reserve Margin (ERM) criteria for Oʻahu, a detailed ERM analysis was performed in PLEXOS using the 1-sigma HDC for wind and solar resources, including rooftop solar, which is a customer resource modeled on the supply-side. Since this analysis was started at the end of 2021, the use of 30% ERM and 1-sigma HDC for wind and solar resources is not consistent with the Decision and Order No. 38482 on June 30, 2022. The resource plans for the Base and Land Constrained scenarios were further examined to determine whether the planned and selected resources met the ERM criteria as bookends on the available variable renewable resources that could be developed. Because the paired variable renewables and storage contribute toward capacity, high and low levels of these resources were considered to examine the operations of the existing generating units and future renewable firm generating units. For example, in 2030, the Base scenario adds 1,740 MW of variable renewables (solar, wind, battery energy storage) while the Land Constrained scenario adds a much lower 270 MW of variable renewables (solar, battery energy storage).

Based on the results of the ERM analysis, several firm generation capacity targets were identified. A range of new firm renewable generators including combustion turbines, combined cycles, internal combustion engines and biomass were added to the Base and Land Constrained scenarios as proxies for the types of proposals that may bid into the solution sourcing process to confirm that most of the capacity need was met. A procurement scenario was then developed based on the capacity expansion and ERM resource adequacy analysis.

Due to on-going discussions regarding ERM and HDC, and expressed commission concerns, significant time was dedicated to assessing resource adequacy using the probabilistic methodology endorsed by the TAP. In consultation with the TAP and STWG, a significant number of sensitivities were run to thoroughly assess resource adequacy in 2029-2030 through reliability metrics such as loss of load expectation, loss of load events, loss of load hours and expected unserved energy.

More on Resource Adequacy

Recently, within the utility industry and locally, there has been a heightened awareness of grid reliability. Figure 11 shows the different components and considerations in ensuring grid reliability.

Figure 11. Grid reliability components and considerations

System Stability	System Balancing	Transmission and Distribution	Resource Adequacy	Resilience
• High penetrations of inverter based resources • Essential reliability services • Frequency, voltage, stability	• Wind and solar variability and uncertainty • Managing and balancing of resources	• Equipment failures, vegetation, auto accidents • Grid modernization – automation and field devices to reduce duration of outages • Outages commonly measured in frequency and duration	• Seasonal demand/load uncertainty • Generator/BESS failures or outages • Multiple days in a row of low solar wind output • 1 day in 4.5 years annual loss of load probability	• Hurricanes, storms, flooding, lava flow, and other extreme weather events • Cybersecurity • Hardened infrastructure • Microgrid solutions

While each type of reliability is important to delivering consistent, reliable electricity, the primary focus of this report is on generation reliability and resource adequacy. As new variable resources are integrated onto the grid and with the desire to retire fossil-fueled generation as soon as practicable, ensuring resource adequacy will be critical to combating climate change and realizing a decarbonized economy. The grid needs analysis takes an in-depth look at this issue.

Resource Adequacy must first be understood and defined. A recent report published in February 2022 by Energy + Environmental Economics, *Resource Adequacy in the Desert Southwest*, defines resource adequacy in the following way:

> Resource adequacy is the ability of an electric power system to produce sufficient generation to meet loads across a broad range of weather and system operating conditions, subject to a long-run reliability standard that limits the frequency of shortfalls to very rare instances. The resource adequacy of a system thus depends on the characteristics of its load—seasonal patterns, weather sensitivity, hourly patterns—as well as its resources—size, dispatchability, outage rates and other limitations on availability. Ensuring resource adequacy is an important goal for utilities seeking to provide reliable service to their customers.

The grid needs analysis provided in this report considers these factors by examining generation reliability in two distinct ways, an energy reserve margin analysis and a probabilistic resource adequacy analysis. Resource adequacy in Hawaiʻi is unique because of the extremely high penetration of rooftop solar and grid-scale solar and storage projects. In addition, Hawaiʻi is not interconnected to any other grid where power can be imported from neighboring states if there are shortfalls in energy supply. Hawaiʻi needs to be energy self-sufficient.

NERC Definition of Adequacy

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

Resilience has also come into sharper focus with recent events on the US mainland and here in Hawaiʻi. While resource adequacy plans for reasonably anticipated events, as discussed later in this report, Hawaiian Electric considered resilience and extreme events in developing the procurement scenario. Further study is needed in this area as resilience is intertwined with other aspects of the grid such as the transmission and distribution system.

6.1 Customer Technology Adoption is a Priority

As described in this section, Hawaiian Electric took a customer first approach to the planning process. Customer technologies are first forecasted based on Hawaiʻi's robust distributed resource market. Their flexibility is maximized to meet grid needs and deliver services. The remaining load to be served is then optimized around grid-scale resources that can meet system needs through the capacity expansion modeling.

6.1.1 Customer Technologies as a Resource to Fulfill Grid Needs

In planning for future grid needs, Hawaiian Electric assumes a forecasted uptake of customer technologies for energy efficiency, distributed energy resources, and electric vehicles. The base set of forecasts for these customer technologies form the best guess of their future adoption and influence the resulting grid needs that are solved for in the subsequent modeling conducted in RESOLVE and PLEXOS. Summarized below are the incremental additions of energy efficiency, solar, and electric vehicles assumed in the Base forecast by 2030.

To reduce carbon by 70% by 2030, in the near-term, in the base scenario the solution sourcing process must seek to acquire customer resources as shown in Figure 12, otherwise carbon reductions may not be realized and put additional strain on the system resources to meet forecasted demand for electricity:

Figure 12. Assumed customer resources needed to achieve 2030 goals

Customer Technology (incremental from 2021 levels)	Peak Load Impact (MW)	Impact to Sales (GWh)	Approximate Quantity
Energy Efficiency	145	1,014	N/A
Electric Vehicles	29	183	43,536 EVs
Private Rooftop Solar	253 (Installed Capacity)	437	26,292 systems
Private Battery Energy Storage	149 MW / 394 MWh (Installed Capacity)	-14	26,261 systems
Non-DER/EV Time-of-Use	4	N/A	N/A

6.1.1.1 Energy Efficiency

A significant portion of load, both capacity and energy, is anticipated to be served through future energy efficiency. While future work in the IGP will include energy efficiency supply curves to determine whether it's optimal to acquire more than the forecast energy efficiency, the base forecast provides a reasonable level of uptake to assume for identifying grid needs. As noted in the March 2022 inputs and assumptions, the energy efficiency forecast is based on projections from the July 2020 State of Hawaii Market Potential Study prepared by the Applied Energy Group (AEG) and sponsored by the Hawai'i Public Utilities Commission. The base forecast is composed of the Business as Usual potential forecast and Codes and Standards forecasts from the potential study. The Business as Usual forecast represents savings from realistic customer adoption of energy efficiency measures through future interventions that were similar in nature to existing interventions. The Codes and Standards forecast represents savings from building codes and appliance standards.

6.1.1.2 Electric Vehicles

The impact of the electrification of transportation on load was forecasted through the adoption of light duty electric vehicles and electric buses. The light duty electric vehicle forecast was based on an adoption model developed by Integral Analytics as described in the EoT Roadmap. The latest unmanaged charging profiles for residential and commercial light duty electric vehicles were updated by leveraging data from the Hawaiian Electric's DC fast charging network and a case study conducted through the deployment of EnelX's Level 2 chargers in Hawai'i. Electric buses were forecast based on information provided by the Hawaiian Electric's Electrification of Transportation team following discussions with several bus operators throughout Honolulu, Hawai'i, and Maui counties.

6.1.1.3 Private Rooftop Solar

Future DER capacity was forecast using two time horizons: near term, over the next three years to reflect the current pace of incoming applications and executed agreements for existing programs and longer term using a model-based approach. The longer term, economic choice model considered the installed cost of PV and BESS systems, incentives, electricity prices, future program structure, and addressable market of customers that have the potential to install DER, among other assumptions.

The future new tariff assumed export compensation and allowed for controllability, based on the standard DER tariff that is proposed in the DER docket. On O'ahu and Maui, the forecast also incorporated the Emergency Demand Response Program, Scheduled Dispatch Program or Battery Bonus and assumed that an upfront incentive of $250/kW would continue beyond Battery Bonus for new DER customers to provide grid services similar to a bring your own device type program.

While the forecasted uptake of DER through Battery Bonus was assumed to export the battery system's rated capacity, if energy was available, for a two-hour duration between 5 PM – 9 PM, DER was modeled as a resource in the RESOLVE and PLEXOS models and split into two classes, uncontrollable legacy DER and controllable future DER that can provide grid services. Modeling DER as a resource is particularly important for assessing resource adequacy as it allows the DER to flexibly serve demand and provide capacity in high need hours while also reflecting changing availability of the PV production for the various weather years modeled.

6.1.1.4 Program Design to Ensure Cost Effective Customer Adoption of DER, EV, and EE

Hawaiian Electric proposed a suite of "freeze" cases to examine the value of forecasted DER, EV, and EE assumed in the load forecast. This modeling will be used in the program design phase of IGP as part of the solution sourcing, to follow the grid needs assessment phase. As the grid needs assessment assumes the forecasted uptake of DER, EV, and EE, the impact of these customer technologies on grid needs is already accounted for. During solution sourcing, the value of the forecasted uptake of DER, EV, and EE will be assessed using the "freeze" cases to determine the compensation and incentives that can be offered cost effectively in the design of new programs and achieve the forecasted levels of DER, EV, and EE that were initially assumed as part of a balanced resource portfolio.

Notwithstanding the above, with DER and EE frozen using the freeze forecasts provided in the IGP inputs and assumptions, additional firm capacity was required to achieve a similar level of reliability as the case with their forecasted uptake by year 2029. This analysis informs the capacity value that these customer-adopted resources provide to the system to fulfill grid needs and is discussed in more detail in Section 6.5.7.

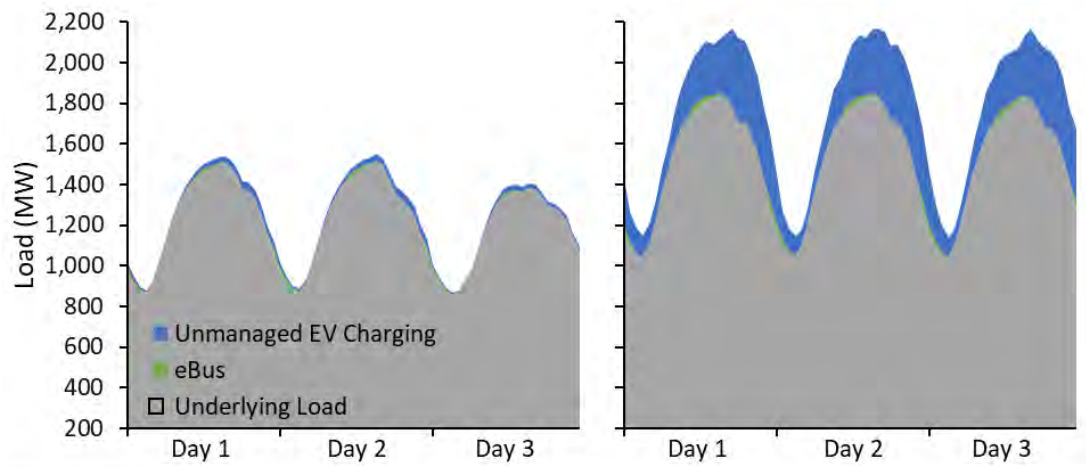
6.1.2 Flexible Customer Resources

Customer resources that include private rooftop solar, distributed battery energy storage, electric vehicles and energy efficiency are necessary to achieve Hawaiian Electric's and the state's decarbonization goals. Customers will seek energy self-sufficiency and resilience by adopting these technologies. Many of these customer resources are flexible and can interact with the grid in a manner that increases the efficiency of grid operations, including contributing to a reliable energy system. Many of Hawaiian Electric's current and planned programs enable this interaction. However, as the distributed energy resource market continues to evolve and customer technologies advance, new innovative programs and customer engagement will be needed. The following sections take a closer look at the future of customer resources in contributing to reliability needs and more efficient grid operations.

6.1.2.1 Managing Flexible Loads

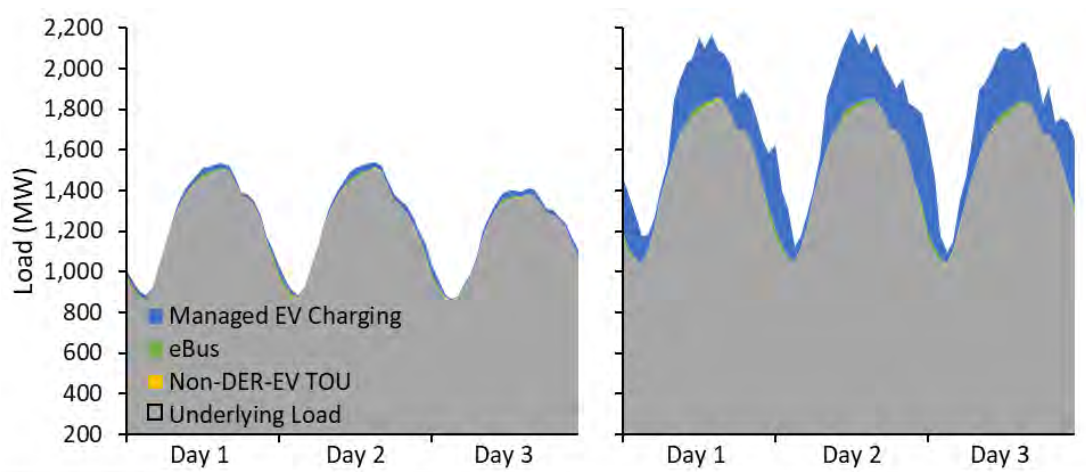
Electric vehicles and electric buses are examples of distributed resources that can increase electricity demand and require more generation resources. In 2030, forecasted electric vehicle charging is a modest incremental load to the system primarily due to the long stock rollover durations for light-duty vehicles. However, as shown in Figure 13, in year 2050, significant load increases are observed due to more electric vehicles on the road in 2050.

Figure 13. Illustrative days showing the impact of unmanaged EV charging. At left, Year 2030; At right, Year 2050



The loads in 2050 are significant, but as shown in Figure 14, managing charging levels can shift some of the unmanaged charging during the evening peak to the daytime when abundant clean solar electricity is available to charge electric vehicles. Electric vehicle charging is considered flexible in that it can be managed to increase system load when the electricity is cheaper and in lower demand.

Figure 14. Illustrative days showing the impact of managed EV charging. At left, Year 2030; At right, Year 2050

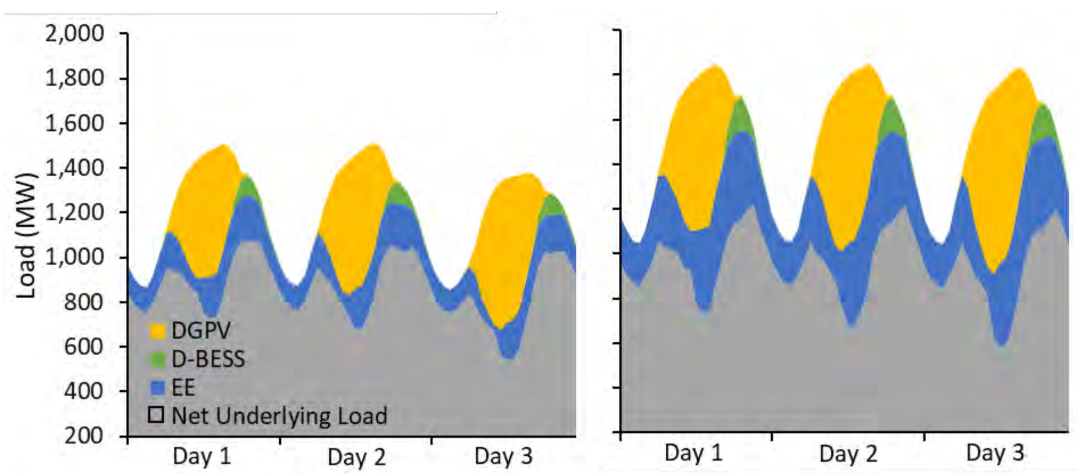


Mandatory time-of-use or TOU rates are envisioned for residential customers who typically use most of their electricity in the evening when returning home from work to cook dinner, take a hot shower, or run their washer and dryer. Hawaiian Electric notes that residential usage has been elevated during the COVID pandemic as it appears that most residents are spending more time at home than pre-pandemic. The forecasted TOU response from customer load changes for customers who do not own DER (rooftop solar) or electric vehicles is quite small. It is expected that the customers with flexible resources like distributed battery energy storage and electric vehicles will be most willing to change habits and shift their energy loads to a low-demand period.

Energy efficiencies, rooftop solar (DGPV) and distributed battery energy storage (D-BESS) are examples of distributed resources that can decrease load or offset load. Energy efficiency measures are permanent in nature in that the load is not necessarily shifting but reduced through more efficient equipment or appliances like air conditioners, heat pump water heaters, LED light bulbs, commercial chillers, among others. The impact of these resources that can reduce or offset loads are seen in Figure 15.

DGPV and D-BESS are normally coupled together and privately owned by customers who may buy or lease such systems to offset their own home load and export any excess. These distributed resources have unique potential. Even though they do not permanently remove load from the system, they are flexible technologies that have the effect of making loads appear flexible. Additionally, in the grid needs assessment, future DGPV is assumed to be controllable on the supply-side of the grid providing flexibility to align DGPV exports with system needs. Aggregated DGPV is also made available to the model as a dispatchable resource providing similar services as grid-scale solar projects. Through customer programs, customers may receive compensation for providing various services to the grid in alignment with system needs. For example, as shown in Figure 15, below, DGPV in aggregate can reduce load during the daytime and when coupled with a battery energy storage system, further reduce loads after the sun goes down, as shown in the green shaded area. Likewise, energy efficiency can significantly reduce loads during all times of the day, putting less strain on the generation system to meet the demand that Hawaiian Electric would otherwise serve.

Figure 15. Illustrative days showing the impact of DGPV, D-BESS and EE. At left, Year 2030; At right, Year 2050



When considering all the various customer technologies together, the remaining load is called the net load which then must be served by grid-scale resources that are provided by Hawaiian Electric or independent power producers. The net load with managed and unmanaged charging is shown in Figure 16 below in the green and gold lines. Managed charging is achieved through price signals such as time varying rates, and other programs such as workplace EV charging. Unmanaged charging is an estimate of when customers would charge their EVs without any price signals or incentives to encourage charging at certain times. As discussed above, because of lower electric vehicle adoption in 2030, there is a small difference in the evening peak between the managed and unmanaged charging. However, in year 2050 with significant load additions from electric vehicle charging, during what is typically the most expensive hours for energy in the evening, there is a significant difference in the net load between the managed and unmanaged electric vehicle charging case. This represents the importance of customers choosing to charge during the day when more generation capacity is available and generally cheaper than during the evening hours.

Figure 16. Daily load flexibility. At left, Year 2030; At right, Year 2050

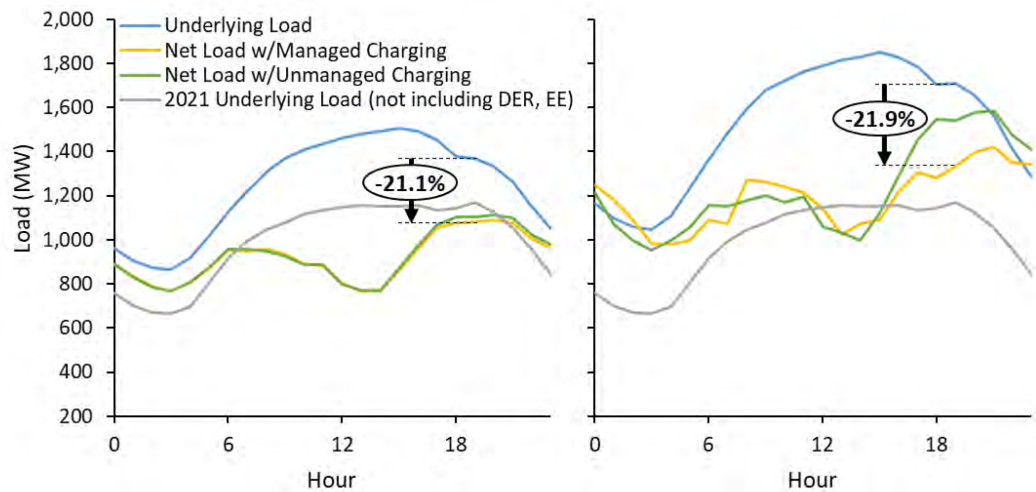
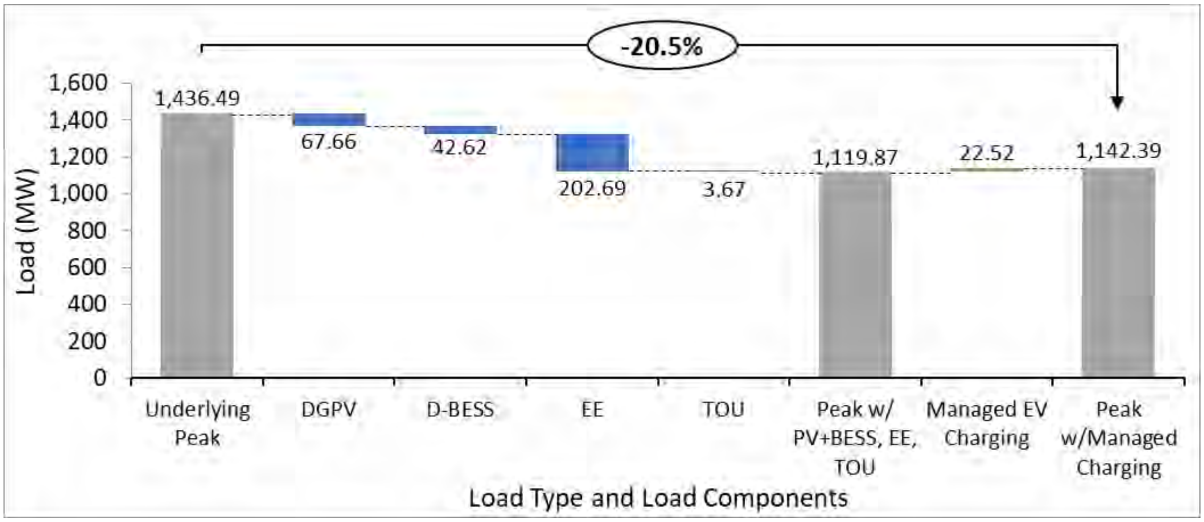


Figure 16 also shows in blue the underlying loads without accounting for customer technologies. This is the load Hawaiian Electric would need to serve if customers did not adopt any efficiencies measures, electric vehicles, DGPV or D-BESS. It means significantly more generating resources would need to be acquired by Hawaiian Electric to ensure sufficient generating resources to meet the demand. Additionally, between the underlying load in blue and the managed charging (due to time varying rates and programs) net load in gold, the load is reduced as much as 22% during the evening hours.

Figure 17 below, shows that in the peak hour in year 2030 the forecasted DGPV, D-BESS, EE and TOU can offset the peak impacts of EV charging, and in total reduce the peak load hour by approximately 20.5%. As electric vehicle charging increases in later years peak reductions are less but still significant.

Figure 17. Reductions in year 2030 peak hour load due to customer resources



6.2 Procurement Scenario for Remaining Grid Needs

This section summarizes the procurement scenario that was optimized and validated by a probabilistic resource adequacy analysis. The procurement scenario was developed using RESOLVE and PLEXOS to optimize and validate resource adequacy and operations of the grid which is further described following this section and in the appendix to this report.

The grid needs analysis that included capacity expansion plans, resource adequacy analysis and an iteration to validate the capacity and energy needs with proxy firm generating resources indicates that the near-term needs of the system that Hawaiian Electric should acquire as part of the Stage 3 procurement are:

- 544 GWhs of renewable dispatchable generation in 2027 to offset energy previously provided by the AES coal plant and provide a market test of the remaining, developable renewable potential that can be put into service by 2027. The target renewable energy can be further adjusted depending on the final outcome of Stage 1 and 2 projects.
- 300-500 MW of renewable firm generation in 2029 or as soon as practicable to facilitate removal from service of older fossil fuel generating units and 200 MW in 2033.
  - Probabilistic testing with a range of firm thermal and variable renewable additions showed that compliance with the three reliability standards (LOLE, LOLH, EUE) can be achieved with 200 – 400 MW of new firm thermal generation. (Section 6.5)
  - ERM testing identified an average need of 536 MW, 165 hours when the removal of KPLP and Mahi was assumed. (Section 6.4.1)
  - The ERM need was validated when 508 – 688 MW of firm generation was added. While residual shortfalls persisted after the firm generation additions, they decreased as the firm thermal capacity additions increased. (Section 6.4.2)

- The targets for variable and firm renewables are consistent with the RESOLVE optimizations and probabilistic testing. The length of time to develop firm generation warrants a more realistic in-service date of 2029.

While 726 GWhs of renewable variable dispatchable generation is selected in 2027 by RESOLVE (Section 6.3), the selected resource by the model is land-based wind. New land-based wind in the immediate-term would likely require additional infrastructure and face community opposition based on recent history of wind projects. While the Assessment of Wind and Photovoltaic Technical Potential determined that 163 MW of land-based wind capacity remains on Oʻahu, the resources are located on the north shore and west side of Oʻahu where development at both locations have been recently opposed by the community. Additionally, on the north shore, an additional transmission substation in Wahiawa would be required according to the REZ study. Therefore, it is recommended to target procurement of renewable energy, after accounting for Stage 1 and 2 projects, needed to offset coal-based energy previously provided by the AES Coal plant and maximize the current transmission infrastructure without triggering the need for new transmission facilities. This will ensure that oil consumption does not substantially increase following the retirement of the AES coal plant. The 544 GWh renewable energy target is approximately equal to the 270 MW land constrained grid-scale solar amount and 75% of the energy selected by the RESOLVE model in 2027. If attractive proposals are received the procurement should allow more than the 544 GWh target to be awarded in the Stage 3 procurement.

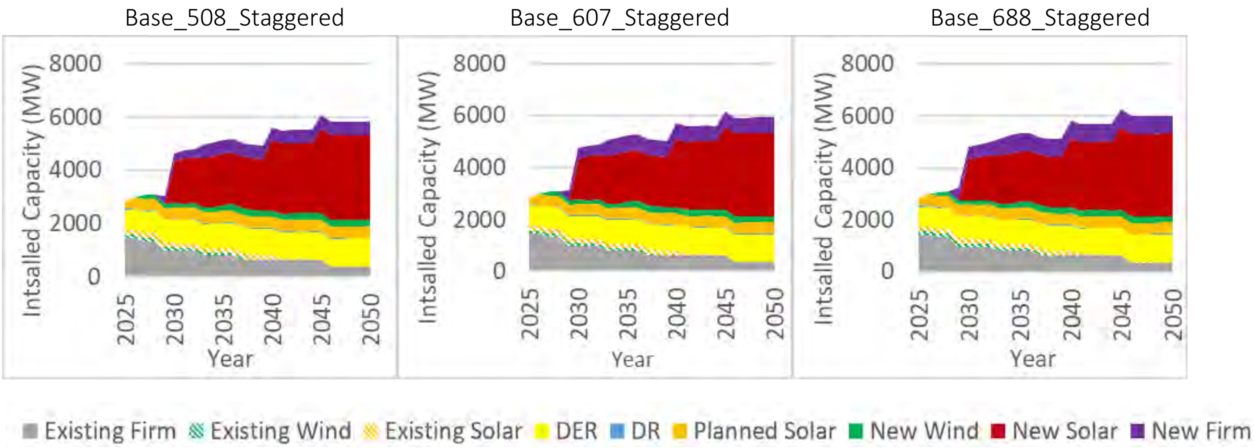
As noted earlier in this report, further work is required to engage communities to develop potential renewable energy zones to interconnect larger amounts of grid-scale renewable energy. This engagement is on-going and is expected to be a key part of the IGP process over the next year in preparation for the competitive procurements to follow the IGP grid needs assessments and following the Stage 3 procurement.

6.2.1 Staggered Installation of Firm Renewable Generation

Due to the possibility that 500-700 MW of renewable firm generation may not be able to be installed by 2029, and to reduce the operational and planning risk of having an entire block of firm generation removed from service in the same year when its contract term ends, the firm unit installations were staggered in different years. For each the 500 MW, 600 MW and 700 MW renewable firm generation scenarios, the total firm capacity is assumed to be installed in 2029, except for 200 MW, which was assumed to be installed in 2033. The 2033 date for 200 MW is approximately when an approved 10-year contract extension of KPLP would be set to expire. An ERM analysis was performed in PLEXOS assuming that approximately 300 MW, 400 MW and 500 MW were installed in 2029 and 200 MW installed in 2033.

Section 9.1 Capacity Expansion Plans provides the resource plan for these cases. Shown below in Figure 18 is the installed capacity trend for various resource categories for the Base_508_Staggered, Base_607_Staggered and Base_688_Staggered scenarios, respectively.

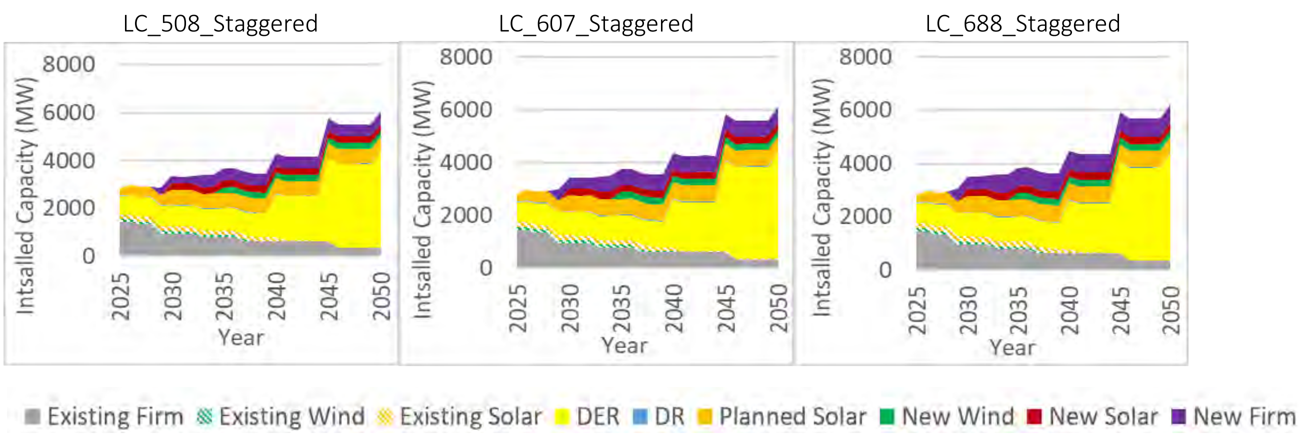
Figure 18. Installed capacity trends for resource categories by scenario. At left, Base_508_Staggered; at center, Base_607_Staggered; at right, Base_688_Staggered



As the existing fossil-fuel firm generation in gray declines over time with the removal of existing thermal generating units from service over the planning period, the replacement thermal capacity of new renewable firm in purple is still much less than the variable renewables considered in the portfolio.

The same firm renewable capacity was installed in the Land Constrained (LC) case. Shown below in Figure 19 is the installed capacity trend for various resource categories for the LC_508_Staggered, LC_607_Staggered and LC_688_Staggered scenarios, respectively. The Land Constrained case, which limits the development of future grid-scale renewables, relies upon distributed paired solar in later years of the planning horizon.

Figure 19. Installed capacity trends for resource categories by scenario. At left, LC_508_Staggered; at center, LC_607_Staggered; at right, LC_688_Staggered



6.2.2 Procurement Scenario ERM Analysis

Hawaiian Electric performed an ERM analysis on the staggering of new firm generation in PLEXOS. A summary of the number of instances of a given capacity shortfall in 2029 and 2033 is shown in Figure 20 and

Figure 21, respectively, for the three different Base scenarios and three different Land Constrained scenarios.

Figure 20. Histograms of capacity shortfall in 2029 grouped by scenario and shortfall magnitude

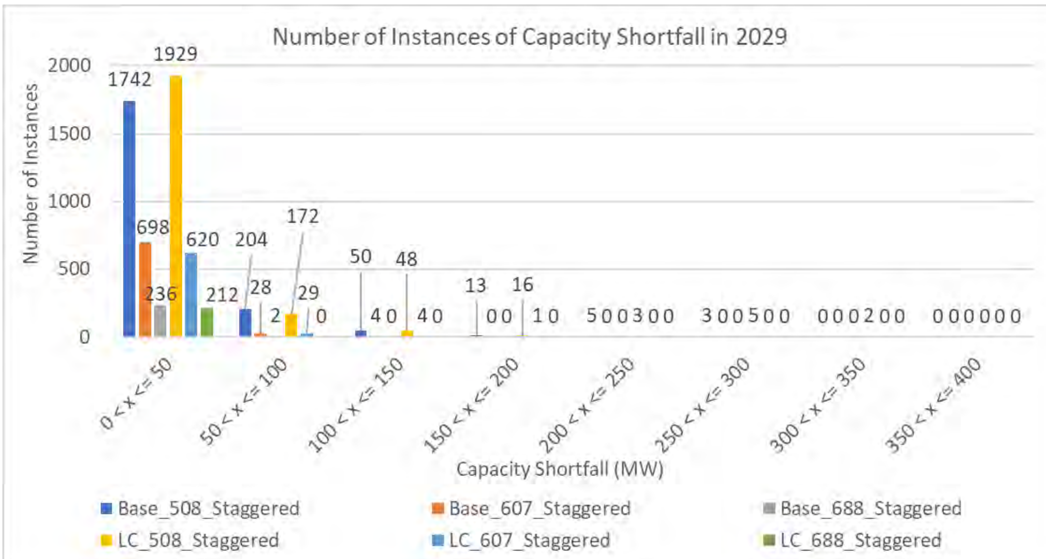
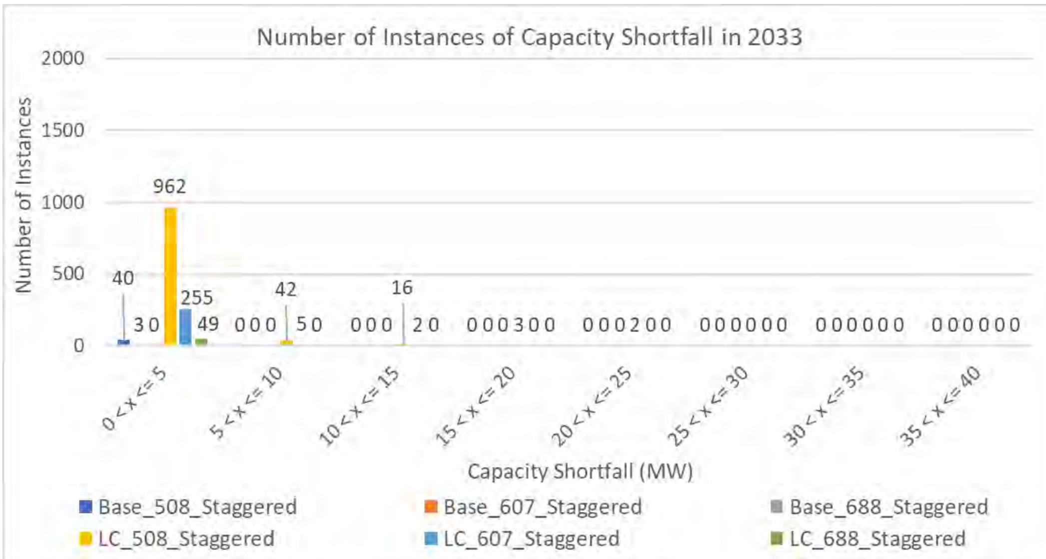


Figure 21. Histogram of capacity shortfall in 2033 grouped by scenario and shortfall magnitude



A summary of the number of instances of a given consecutive hours shortfall in 2029 and 2033 is shown in Figure 22 and Figure 23, respectively, for the three different Base scenarios and three different Land Constrained scenarios.

Figure 22. Histograms of capacity shortfall in 2029 grouped by scenario and shortfall duration

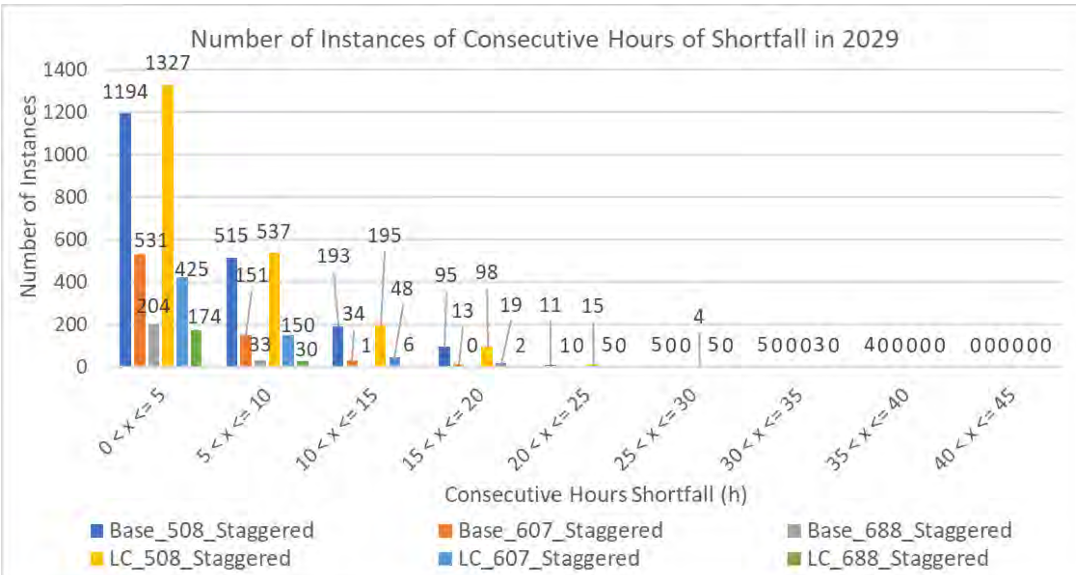
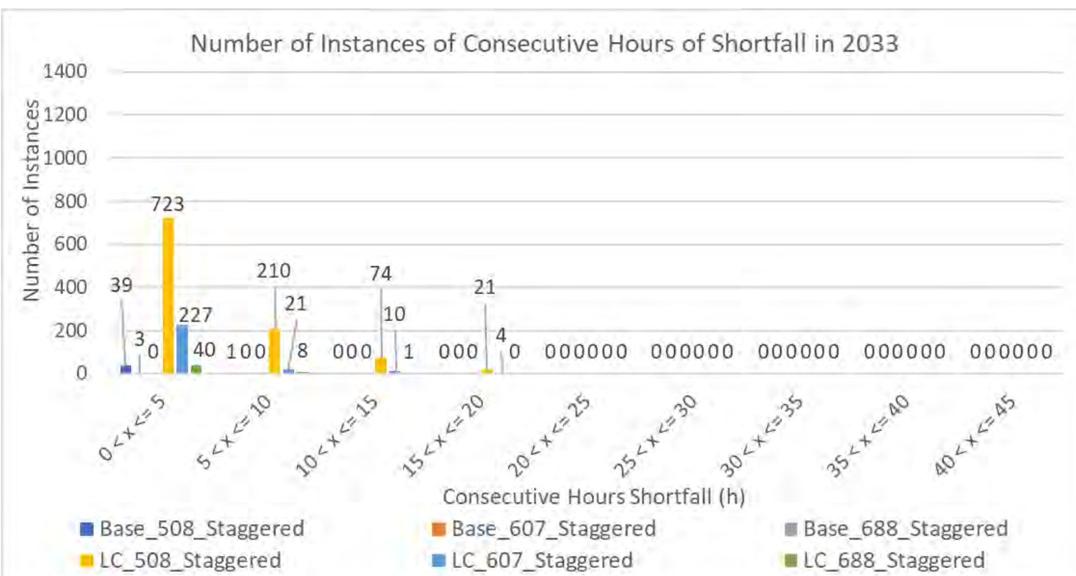


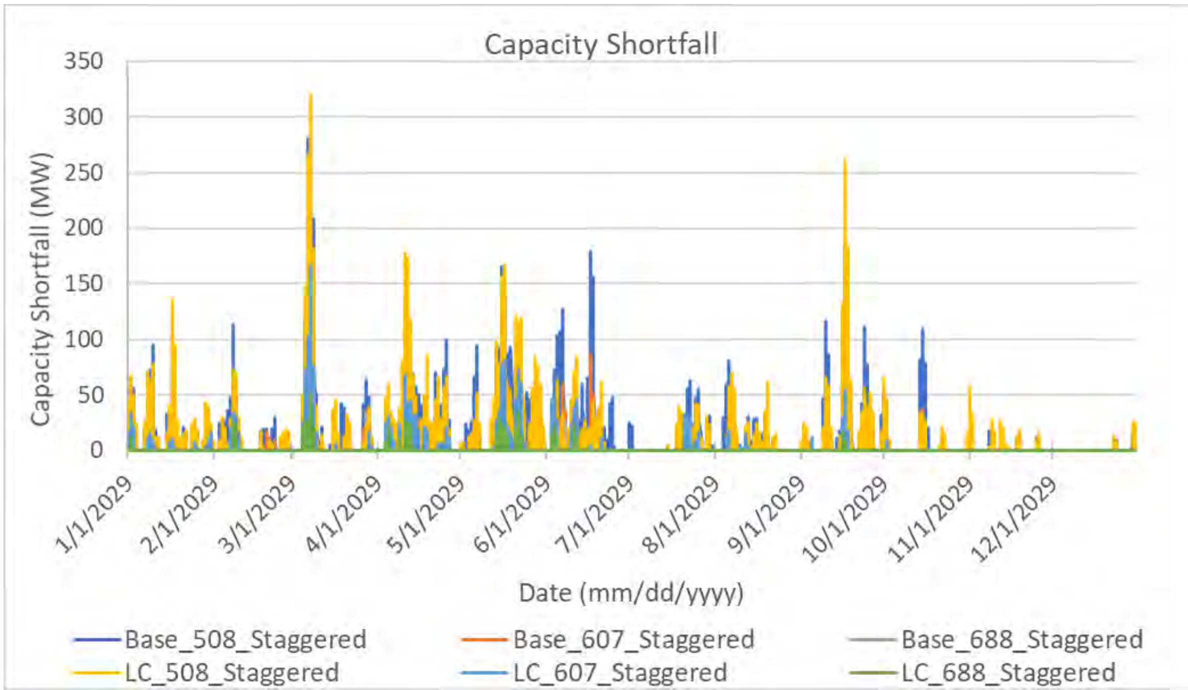
Figure 23. Histograms of capacity shortfall in 2033 grouped by scenario and shortfall duration



When the firm resource is added in 2029, the capacity shortfall and number of instances of shortfall decreases. Similarly, when the firm resource is added in 2029, the consecutive hours shortfall and number of instances of shortfall decreases. The Base scenario also has less shortfall, both in magnitude and frequency, than the Land Constrained case due to the higher amounts of renewables added.

Shown below in Figure 24 is a detailed look of the capacity shortfall for the three different Base scenarios and three different Land Constraint scenarios in 2029. As expected, as the size of the firm capacity increases, there is less capacity shortfall.

Figure 24. Year 2029 hourly capacity shortfall. Base and Land Constrained (staggered) scenarios



Shown below in Figure 25 and Figure 26 is the dispatch for a high-renewable day in 2029 and low-renewable day in 2029, respectively. Note that this is the dispatch in the ERM analysis, and therefore, variable renewable production is defined by the HDC and is not representative of the dispatch of the new firm units during normal operation.

Similar to the previous section, even on a day with high renewable energy and the large number of renewables added in 2030, the new firm generators are still needed to help meet the capacity and energy requirement. The need for firm generation to help meet the capacity and energy requirement is increased on the low-renewable days, as well as, when existing firm generation is removed from service in 2033.

Figure 25. Daily chart – ERM simulation – Base_508_Staggered scenario – High renewable day

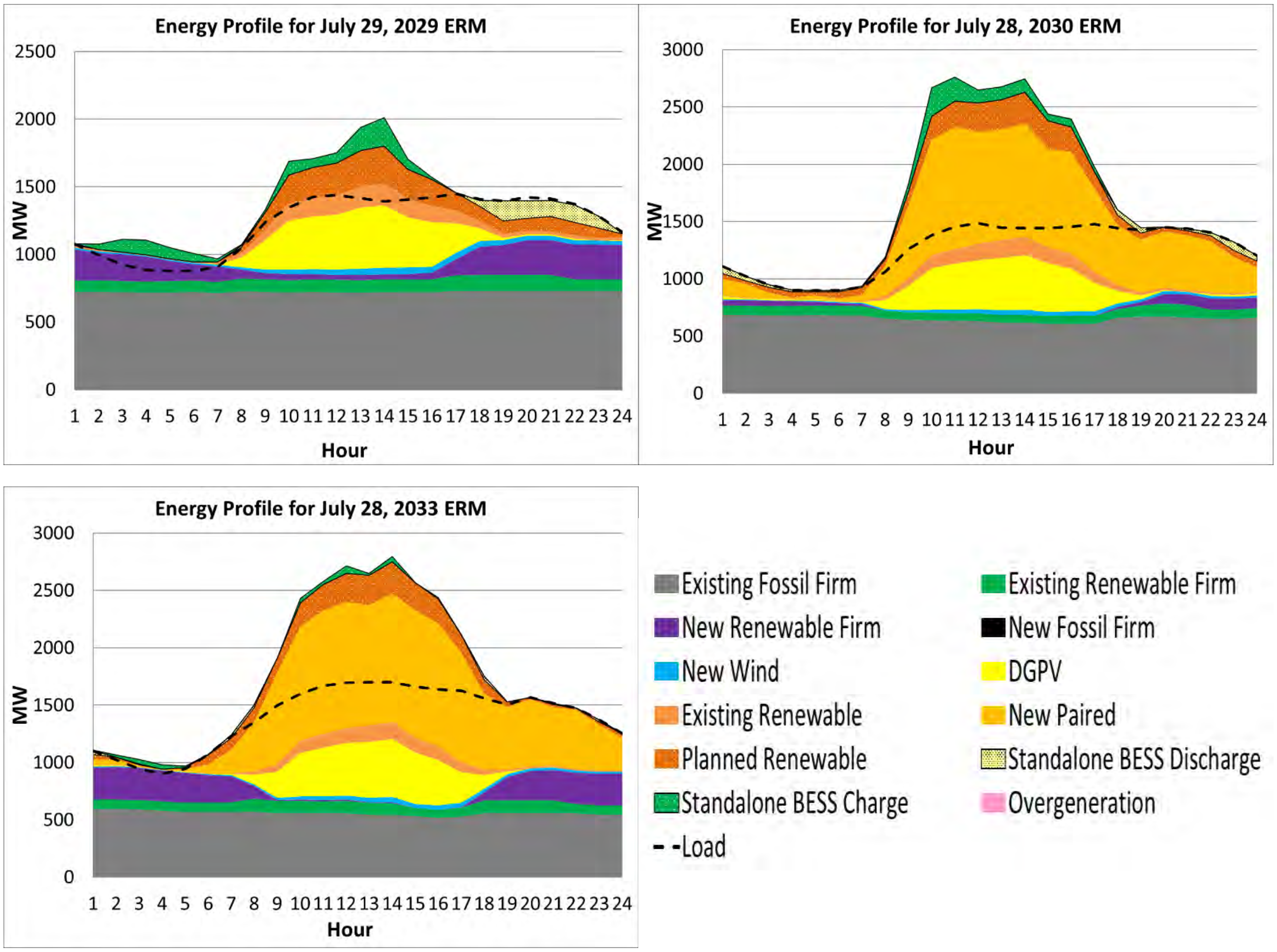
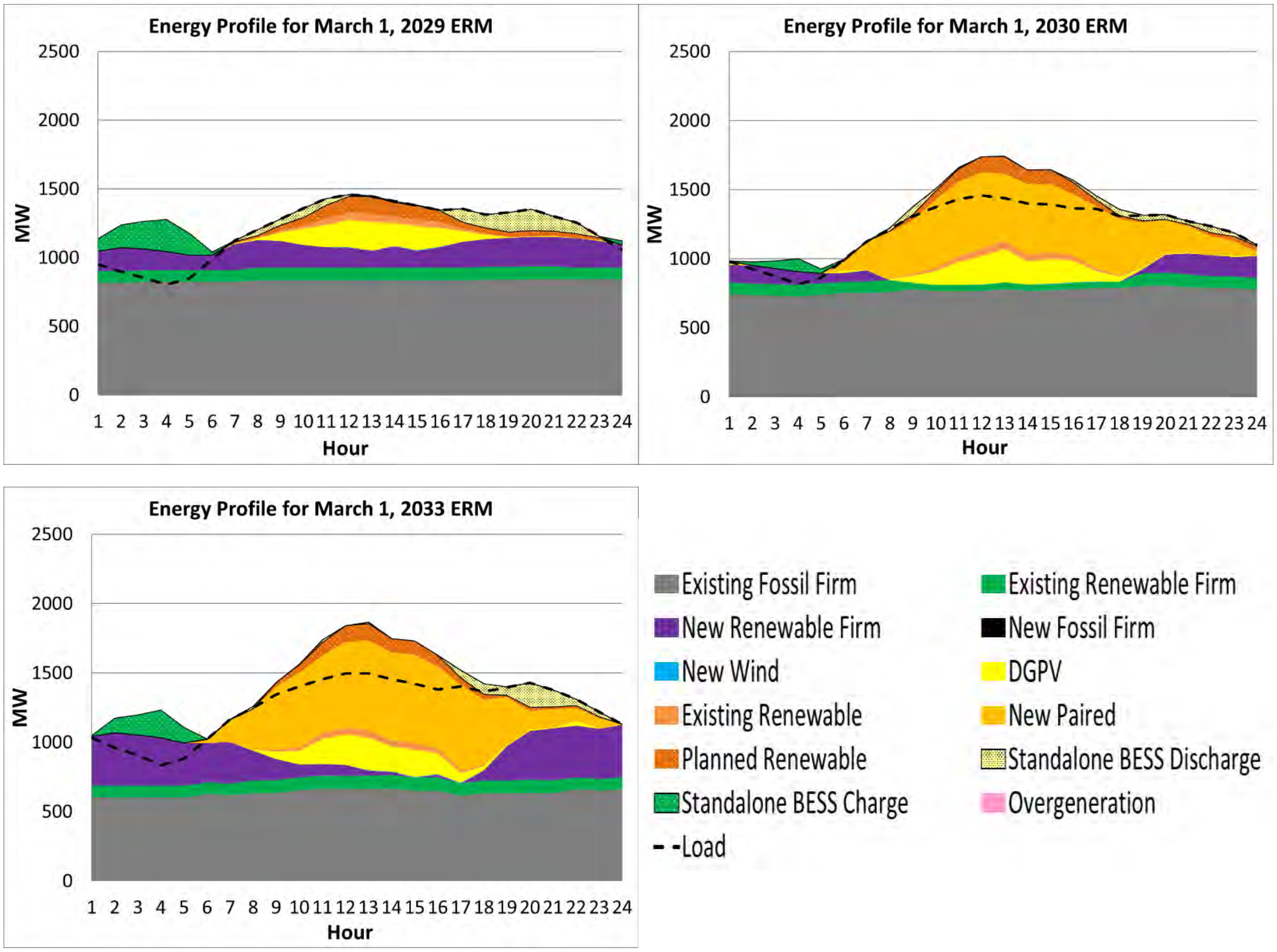


Figure 26. Daily chart – ERM simulation – Base_508_Staggered scenario – Low renewable day



6.2.3 Procurement Scenario Probabilistic Analysis

As detailed in Section 6.5, the reliability impact of adding resources varies by resource type and quantity. Several different resources were evaluated to address reliability concerns in year 2029 including firm generation, hybrid solar, land-based wind, offshore wind, long-duration energy storage, short-duration energy storage, and delayed deactivation of existing generators. The analyses also demonstrate that there are diminishing returns on the extended addition of one resource type and that there are portfolio benefits to adding a diverse mix of resources to address reliability concerns.

In Section 6.5.2, at lower additions of hybrid solar (paired PV + BESS), greater amounts of thermal generation may be needed to achieve reliability. Cases were run with 270 MW of hybrid solar and 400 MW of firm thermal generation, 958 MW of hybrid solar and 300 MW of firm thermal generation, and 1,600 MW of hybrid solar and 200 MW of firm thermal generation. Each of these cases resulted in reliable systems as measured by established reliability metrics for LOLE, LOLH and EUE used by other jurisdictions.

In Section 6.5.3, curve fitting of the probabilistic cases where incremental additions of hybrid solar and firm generation were examined resulted in more precise firm generation additions where the curve fit was interpolated to meet the EUE standard of 0.002% of load. The firm thermal additions, curve fit to the EUE standard, suggests that firm generation additions ranging between 175 MW to 300 MW compared to the resource blocks previously modeled (200-400 MW). However, 300 MW of firm generation by 2029 is still appropriate to meet reliability standards in the near-term given uncertainties and risks associated with the current generation fleet, uncertainties surrounding renewable development and community acceptance, supply chain of renewable generation equipment, electrification of transportation, among others. This was informed by analyses conducted around the Land Constrained scenario based on stakeholder feedback for remaining developable onshore renewable potential and recognizing that the result of community engagement on REZ may further reduce the technical resource potential that NREL identified in their revised Assessment of Wind and Photovoltaic Technical Potential. Additionally, further opportunities to retire additional fossil-fuel generation can be explored as more renewable resources are brought online over the next decade to ensure that the procurement of at least 300 MW today does not adversely impact cost and reliability over the long-term.

In Section 6.5.4 and 6.5.8, the impact of additional standalone storage was examined: 12-hour duration to proxy a future long duration storage or pumped storage hydro and 2-hour duration to proxy a future demand response program. While both resources improved reliability, their impact was less than if the same capacity for a firm thermal resource was added instead.

In Section 6.5.5, delayed removal of existing fossil-fuel generators was examined and contrasted against the addition of new thermal generators. While delaying the deactivation of existing units can improve system reliability, it is not a 1:1 substitution with a new thermal unit. Greater improvement in reliability was observed at higher levels of new thermal generation even if the total firm generation (existing plus new) was less. This is due to the higher forced outage rates of the existing thermal units to reflect their declining availability as they continue to age, as noted in Section 6.5.1.

In Section 6.5.6, the high load and low load bookends of the IGP forecast were examined with 300 – 400 MW of firm thermal generation and 270 MW of hybrid solar (from the land constrained scenario). At the high load bookend, more than 400 MW of firm generation may be needed to bring LOLE within the US Mainland standard of 0.1, especially if future variable renewables are constrained to 270 MW. At the low load bookend, 400 MW of firm generation is sufficient to meet the reliability standards and further removal of existing thermal generators could be considered; however, 300 MW of firm generation does not result in a reliable system.

In Section 6.5.7, a combined DER and EE freeze case was conducted to get an indicative value of the capacity that is provided by the incremental DER and EE assumed in the forecast. In the absence of the incremental DER and EE that is adopted by year 2029, a new firm addition of nearly 500 MW would be needed for LOLH and EUE to meet the reliability standard. Additional firm generation would still be required to meet LOLE.

In Section 6.5.9, increments of firm generation were considered with the addition of 270 MW of hybrid solar and 400 MW of offshore wind. While 400 MW of offshore wind improved reliability, more than 300 MW of firm generation would still be required to meet reliability for LOLE.

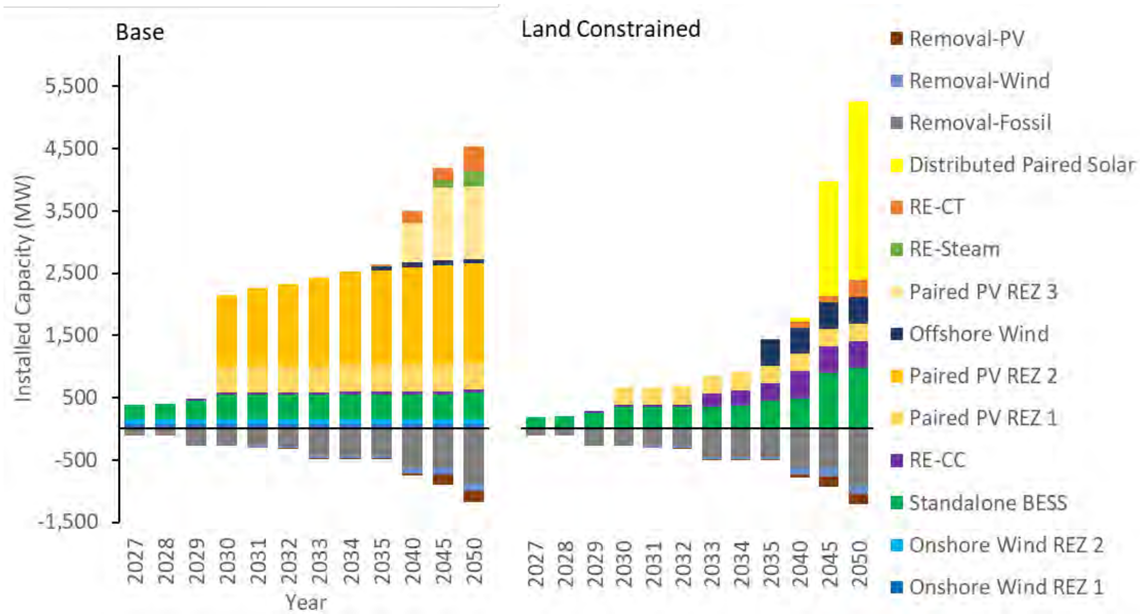
In Section 6.5.10, the reliability of various portfolios was examined when an extended outage of 438 consecutive hours was experienced by each resource type. In portfolios without new firm generation, the extended outage of onshore wind, hybrid solar, and standalone BESS had similar reliability as the base case without an extended outage indicating that the existing thermal resources compensated for the extended outages of those new resources. This is like the Kona Low that was experienced in December 2021 where the variable renewables had reduced output for an entire day. Similarly, in portfolios with new firm generation, if an extended outage was experienced by onshore wind, hybrid solar, and standalone BESS, there is no negative impact to reliability. However, when the new firm thermal generation is on extended outage, the other resources are not able to compensate, resulting in unserved energy.

6.3 Capacity Expansion Plans (RESOLVE)

As described in Section 5, four scenarios were run to determine the optimal least cost resource mix to achieve 100% renewable energy. The "bookend" cases recommended by the TAP provide a wide range of load cases to assess the impact uncertainties in future load may have on the optimal mix of renewable resources given RPS mandates, cost of commercially available technologies, reliability and operational rules. Due to the uncertainty in land use on Oʻahu to develop renewable energy projects, "bookends" on the amount of available land were also tested with the Land Constrained scenario that does not allow new onshore wind projects and limits solar build to 270 MW beyond Stage 1 and 2 projects.

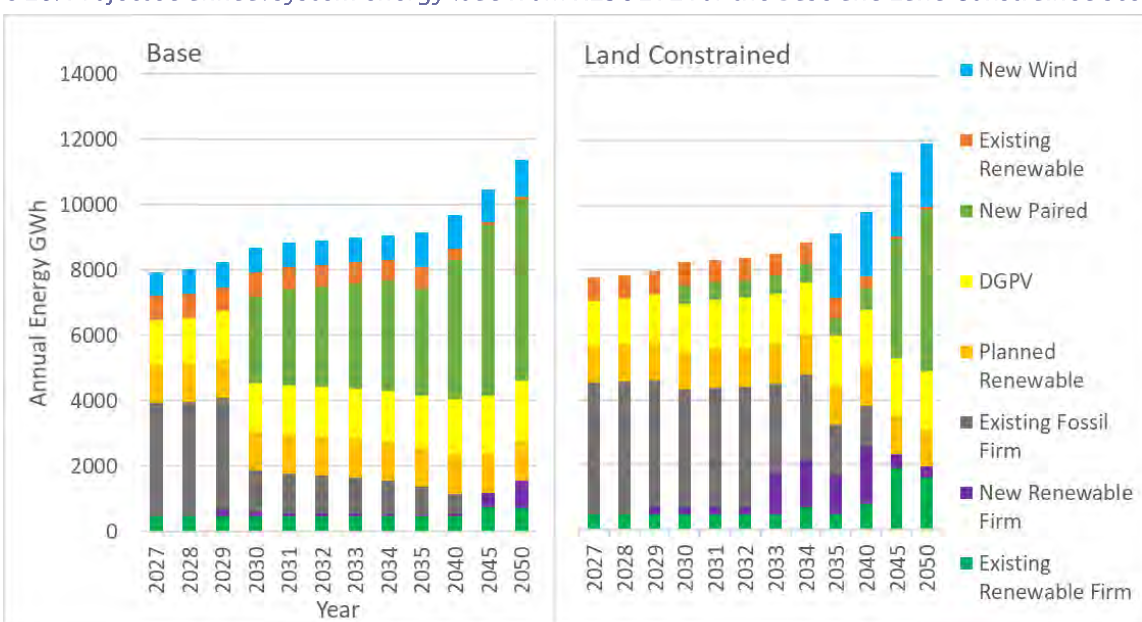
Shown below in Figure 27 are the resource plans from RESOLVE for the Base and Land Constrained scenarios.

Figure 27. Resource plans from RESOLVE for the Base and Land Constrained scenarios



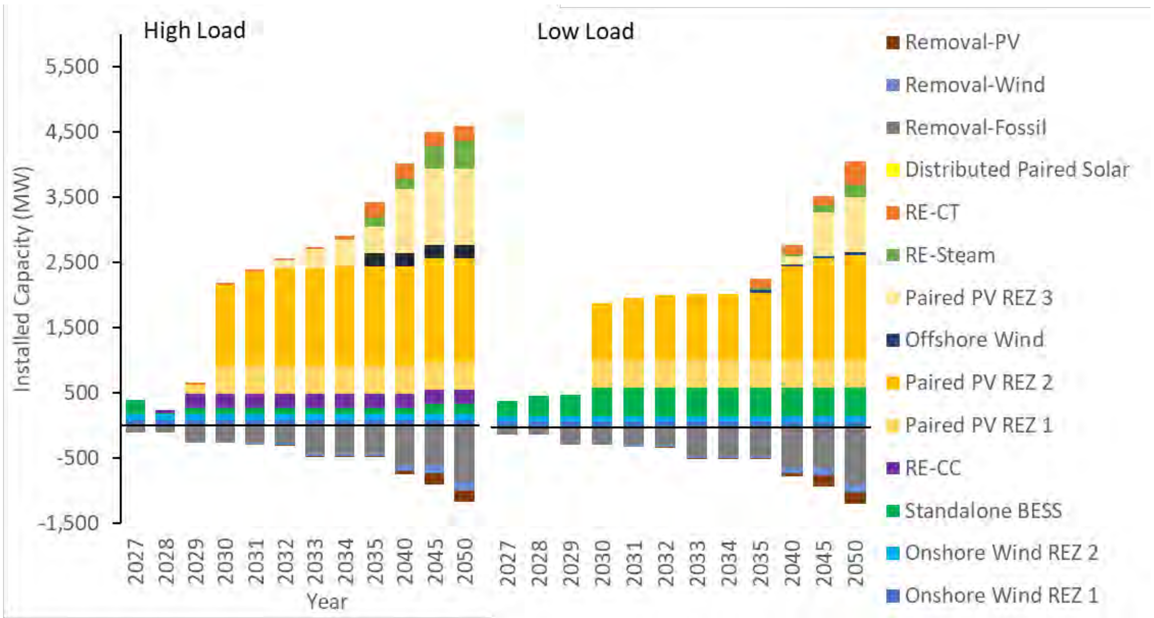
Shown below in Figure 28 are the annual energy (GWh) from RESOLVE for the Base and Land Constrained scenarios.

Figure 28. Projected annual system energy load from RESOLVE for the Base and Land Constrained scenarios



Shown below in Figure 29 are the resource plans from RESOLVE for the High Load and Low Load scenarios.

Figure 29. Resource plans from RESOLVE for the High Load and Low Load scenarios



Shown below in Figure 30 are the annual energy (GWh) from RESOLVE for the High Load and Low Load scenarios.

Figure 30. Projected annual system energy load from RESOLVE for the High Load and Low Load scenarios

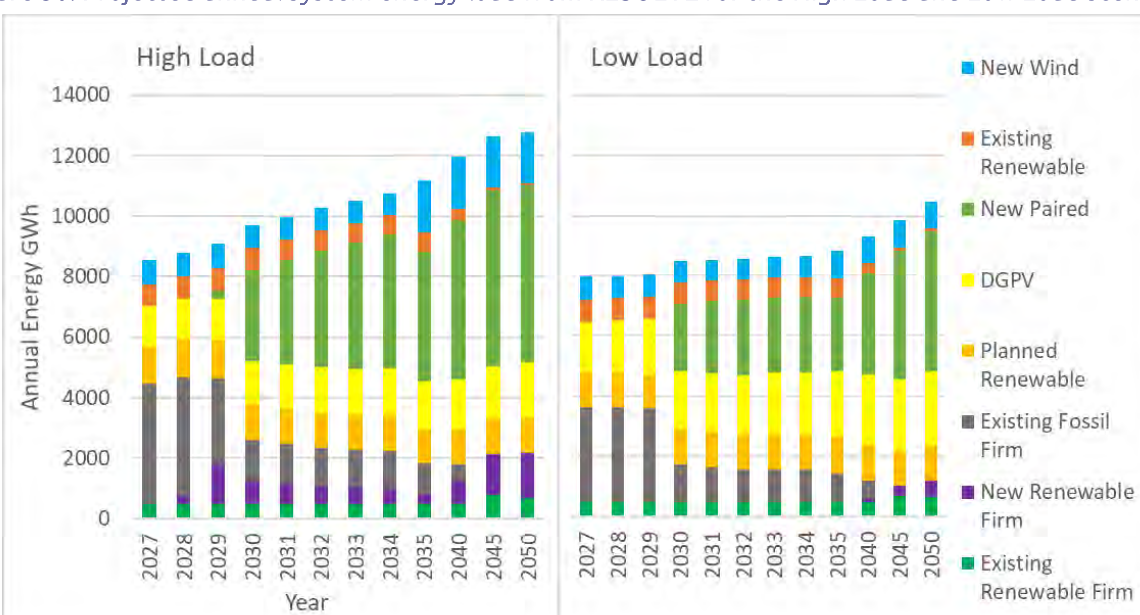


Figure 31. Capacity from RESOLVE for the Base, Low Load, High Load and Land Constrained scenarios

Capacity (MW)	Base			Land Constrained		
	2030	2040	2050	2030	2040	2050
Existing Renewable Firm	77	77	436	77	77	436
New Renewable Firm	35	251	690	39	508	692
Existing Fossil Firm	921	580	0	921	580	0
Planned Renewable	585	585	585	585	585	585
DGPV	803	936	1008	803	936	1008
New Hybrid Solar	1577	2623	3187	270	338	3006
Existing Renewable	336	174	45	336	174	45
New Onshore/Offshore Wind	163	241	241	0	400	400

Capacity (MW)	Low Load			High Load		
	2030	2030	2030	2030	2040	2050
Existing Renewable Firm	77	77	77	77	77	436
New Renewable Firm	0	0	0	250	596	877
Existing Fossil Firm	921	921	921	921	580	0
Planned Renewable	585	585	585	585	585	585
DGPV	1042	1042	1042	776	911	983
New Hybrid Solar and Distributed Solar	1290	1290	1290	1677	2943	3187
Existing Renewable	336	336	336	336	174	45
New Onshore/Offshore Wind	163	163	163	163	368	368

The RESOLVE resource plans for the bookends shown in Figure 31 provide useful information to understand how the selected resources can meet future grid needs, given the uncertainty in forecasted load and assumed variable renewable resource availability. Over the 2027-2050 planning horizon, between the Base, Low Load and High Load scenarios, there is consistency in the types of resources selected. The remaining available onshore, land-based wind resource potential is selected because of its assumed high-capacity factor and low cost. Then starting in 2030, for these cases, between 1,300 and 1,600 MW of hybrid solar are selected in the models. Greater amounts of new firm thermal capacity are built as load increases from the low load to the base to the high load scenarios. This indicates that between the bookends, the grid needs are based on similar resources being selected in the models and that there is only a difference in timing when those resources are built to meet the forecasted load. This also indicates that other load cases are unnecessary since the bookends capture a consistent resource mix across wide-ranging load scenarios.

In the Land Constrained scenario, new land-based renewables are limited. Hybrid solar is built up to its assumed limit of 270 MW and the highest amount of offshore wind is built at 400 MW. In later years of the planning horizon, paired distributed solar is selected, reaching over 90% of the technical rooftop potential for this resource as identified by NREL in their resource potential study. There is a large amount of distributed solar paired with energy storage at the end of the planning horizon, is selected likely for compliance with RPS mandates. The model does not select this resource in earlier years like it does grid-scale facilities likely due to the cost of the distributed solar resource. Future technological advancement in the coming years may also be available to compete with the distributed solar resource through solution sourcing. Lastly, as shown in the energy charts above, the Land Constrained scenario has the slowest transition off fossil-fuels. Additional details on the RESOLVE capacity expansion analysis are available in the appendix to this report.

6.3.1 Renewable Energy Zones

The RESOLVE modeling also demonstrates that the development of renewable energy zones by 2030 is cost-effective as RESOLVE groups 1 and 2 are selected covering West, Central and Windward Oʻahu. The northern REZ that covers Wahiawa to the North Shore is selected in later years and has the highest REZ enablement costs. However, it is critically important to note that groups 1 and 2 also include solar on 30% sloped land, as shown below in Figure 32. The Base scenario builds approximately 1,600 MW of grid-scale solar paired with energy storage from RESOLVE REZ groups 1 and 2 in 2030, of which 523 MW is located on slopes less than 15%.

Figure 32. REZ group capacity broken down by slope for solar resources

RESOLVE REZ Group Capacity (MW)	Slope ≤ 15%	15% > Slope ≤ 30%	Total
Group 1 (1, 2, 7 from the REZ Study)	84	426	510
Group 2 (3, 4, 5, 6 from the REZ Study)	439	1,235	1,674
Group 3 (8 from the REZ Study)	435	725	1,160
Total by Slope	**958**	**2,386**	**3,344**

The Stage 3 near-term procurement should seek to maximize the remaining capacity on the transmission system and substation sites without triggering the development of REZ infrastructure. Through IGP and other initiatives, community engagement must continue with affected communities prior to initiating any REZ infrastructure. Market and commercial interests must also be engaged to determine the viability of developing renewable energy projects on these lands, especially on slopes greater than 15%.

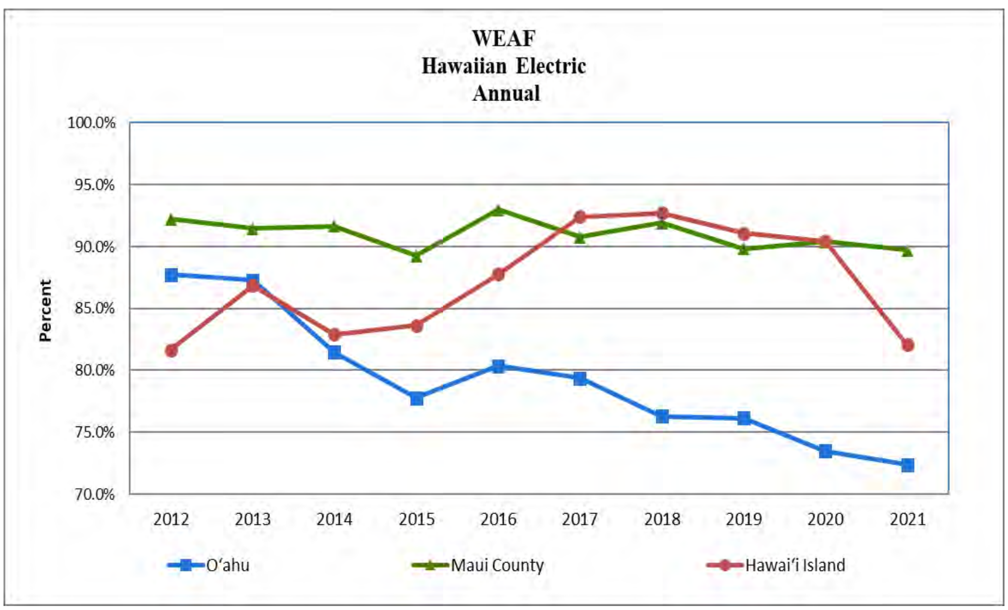
6.3.2 Modeling Iteration and Sensitivity of Thermal Resource Selection to ERM Target and HDC

In the RESOLVE cases modeled in the previous section, existing and new firm generation have an HDC of 1 or 100%, where there are no assumed derates for maintenance or forced outages. Based on TAP feedback, an iteration was conducted between the probabilistic analysis and RESOLVE to verify whether the resource mix changes when firm thermal generation is not given 100% capacity credit towards meeting the ERM. This would mitigate any bias the model may have towards firm thermal generation. A thermal HDC was applied in RESOLVE to represent the availability of thermal units after both types of outages. For existing units, the 2021 Weighted Equivalent Availability Factor (WEAF) was used. This metric is the percentage of time a fleet of generating units is available to generate electricity, weighted for generator size where larger generators have a greater effect on WEAF, and includes planned and unplanned outages. The historical WEAF is reported quarterly as part of the Key Performance Metrics. For new CTs, the net of the forced outage rate (1.3%) and maintenance outage rate (1.3%) was used.

- Oʻahu existing firm generation HDC = 72.37%
- Oʻahu new firm generation HDC = 97.4%

The existing firm generation HDC reflects the declining availability of the existing thermal fleet, as shown in the historical WEAF in Figure 33, and is a complementary assumption to the increased forced outage rate that was discussed in Section 6.5.1.

Figure 33. Historical WEAF by county



Several cases were evaluated with the firm HDC, including cases where the ERM target was varied in 10% increments.

- Base_wKPLPMahi
  - Base case modeled in RESOLVE, KPLP and Mahi added as planned resources after optimization
  - Existing firm HDC = 100%, New firm HDC = 100%, and ERM Requirement = 30%
- Base.v2
  - Base case without KPLP and Mahi
  - Existing firm HDC = 100%, New firm HDC = 100%, and ERM Requirement = 30%
- Base.v3_30ERM
  - Base.v2 with HDC applied to firm units
  - Existing firm HDC = 72.37%, New firm HDC = 97.4%, and ERM Requirement = 30%
- Base.v3_20ERM
  - Base.v2 with HDC applied to firm units
  - Existing firm HDC = 72.37%, New firm HDC = 97.4%, and ERM Requirement = 20%
- Base.v3_10ERM
  - Base.v2 with HDC applied to firm units
  - Existing firm HDC = 72.37%, New firm HDC = 97.4%, and ERM Requirement = 10%
- Base.v3_0ERM
  - Base.v2 with HDC applied to firm units
  - Existing firm HDC = 72.37%, New firm HDC = 97.4%, and ERM Requirement = 0%
- Land Constrained
  - Base case without future onshore wind, 270 MW limit on paired PV+BESS, no biomass, and 400 MW limit on offshore wind.
  - Firm HDC = 100% and ERM Requirement = 30%
- LC.v3_10ERM
  - Land Constrained without KPLP and Mahi, with HDC applied to firm units
  - Existing firm HDC = 72.37%, New firm HDC = 97.4%, and ERM Requirement = 10%

The results of the firm HDC cases are summarized below.

Figure 34. Buildout sensitivity using firm HDC and different ERM targets

Year 2030	Base_wKPLP Mahi	Base.v2	Base.v3_30E RM	Base.v3_20E RM	Base.v3_10E RM	Base.v3_0ER M	Land Constrained	LC.v3 10ER M
Existing firm HDC (%)	100	100	72.37	72.37	72.37	72.37	100	72.37
New firm HDC (%)	100	100	97.4	97.4	97.4	97.4	100	97.4
ERM Requirement (%)	30	30	30	20	10	0	30	10
New Firm (selected by RESOLVE)	35	264	521	408	300	213	39	342
Existing Firm	1,175	967	967	967	967	967	967	967
Standalone PV	0	0	0	0	0	0	0	0
Paired PV (Hybrid Solar)	1,577	1,640	1,401	1,556	1,594	1,741	270	270
Onshore Wind	163	163	163	163	163	163	0	0
Offshore Wind	0	0	0	0	0	0	0	0
Standalone Storage (MW/MWH)	379 MW / 712 MWh	66 MW / 124 MWh	67 MW / 127 MWh	64 MW / 122 MWh	61 MW / 115 MWh	75 MW / 140 MWh	321 MW / 600 MWh	14 MW / 26 MWh
Paired Storage (MW/MWH)	1,577 MW / 4,461 MWh	1640 MW / 5,100 MWh	1401 MW / 3,639 MWh	1,556 MW / 4,502 MWh	1,594 MW / 4,770 MWh	1,741 MW / 5,613 MWh	270 MW / 270 MWh	270 MW / 270 MWh

Across the Base cases, a high amount of hybrid solar is selected. In cases where the ERM target was adjusted downward from 30%, a relatively constant amount of new hybrid solar and new firm thermal generation was selected in RESOLVE with hybrid solar increasing and firm thermal decreasing as the target trended downward. In the Base case without KPLP, new firm generation is selected by RESOLVE to replace the capacity that is lost when this unit is removed. Importantly, with some ERM target to plan for, RESOLVE selects between 300 – 500 MW of new firm generation. In the Land Constrained case where new hybrid solar was limited, increased amounts of firm generation are selected with a lower ERM target and firm HDC. The results of the thermal HDC testing are consistent with the results of the probabilistic resource adequacy where a similar amount of new thermal capacity in the range of 300 – 400 MW was identified.

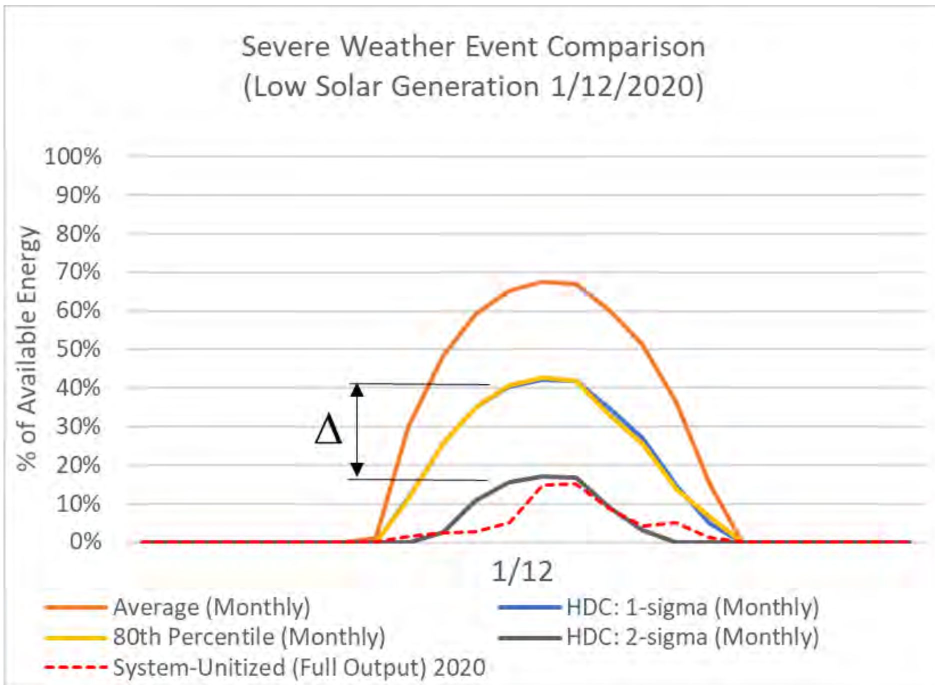
In summary, the ERM and HDC approach does not bias the optimal mix towards firm thermal generation as similar amounts of hybrid solar are selected compared to the original set of RESOLVE cases modeled. The optimal resource mix generally does not change except for the amount of firm generation that is selected depending on the level of ERM. These cases also produce firm generation amounts that are consistent with the probabilistic analyses that indicates somewhere between 200-500 MW of firm generation is needed depending on the desired level of reliability.

6.4 Resource Adequacy – Energy Reserve Margin

Hawaiian Electric performed an ERM analysis in PLEXOS using the Base, Low Load, High Load and Land Constrained resource plans produced by RESOLVE. Firm resources selected by RESOLVE were removed in the ERM analysis to determine the actual shortfall need (i.e., unserved energy) in magnitude (MW) and duration (hours). The ERM analysis accounts for the capacity value from the future variable renewable and storage resources selected by RESOLVE.

As noted earlier, the 1-sigma HDC and 30% ERM target were used in this analysis. The 1-sigma HDC is similar to the 80th percentile HDC that was ultimately adopted following discussion with the TAP. Because this analysis was started at the end of 2021, the analysis assumes the use of 1 sigma HDC and 30% ERM which is different than recent Commission guidance issued in D&O No. 38482 on June 30, 2022. While the methodology to calculate the HDC uses a typical day-of-the-month approach to expand the available datapoints used in the HDC calculation, it also means that all days within a month will have the same hourly profile. Therefore, the current HDC has no day-to-day variability and may overstate the capacity contributions of PV and wind on certain days.

Figure 35. Comparison of solar HDC calculations

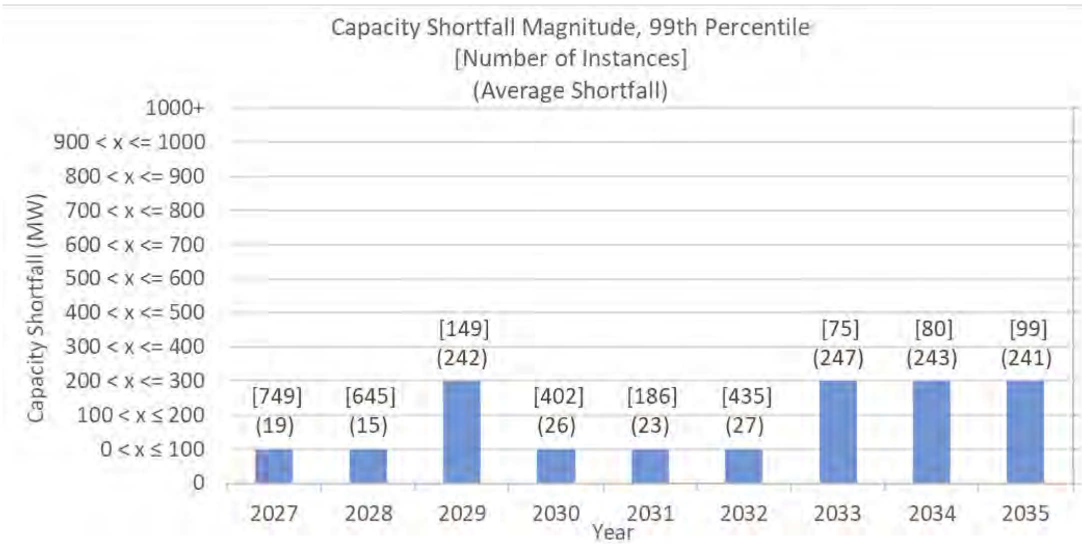


- Significant overlap of 1-sigma and 80th percentile profiles
- However, 1-sigma or 80th percentile would overstate the available energy on this day.

Figure 35 compares the 80th percentile, 1-sigma, and 2-sigma solar HDCs calculated for a typical day of the month as discussed with the TAP on January 20, 2022. On this example day, the 1-sigma and 80th percentile HDCs show good alignment with each other. Still, they are higher than the simulated PV production using NREL's weather dataset, shown by the red dotted line, and the 2-sigma HDC that more closely matches the NREL's simulated production.

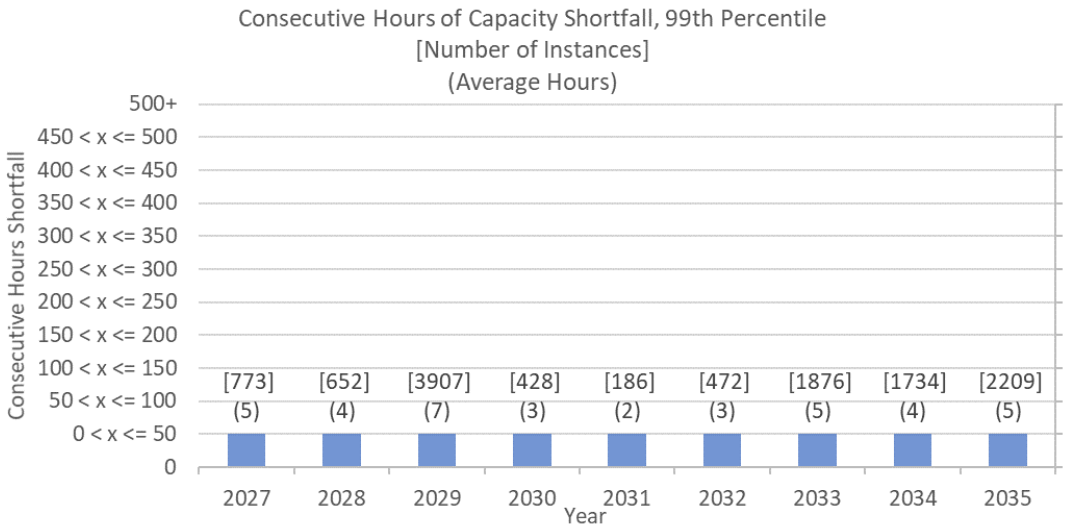
Shown below in Figure 36 is the number of instances of a given capacity shortfall each year and in parentheses is the average capacity shortfall for the range. 99th percentile means 99% of all shortfall instances are less than or equal to the capacity shown. The 99th percentile is used here to define the capacity shortfall to include most instances except for the most extreme outliers. Using 2029 as an example, 99% of the capacity shortfall is 300 MW or less, there are 149 instances of capacity shortfall between 200 MW and 300 MW, and the average shortfall in the 200 MW to 300 MW range is 242 MW. The capacity need identified is intended to reduce the risks of over-procuring by accounting for contributions from future variable renewables and storage toward meeting future capacity needs and by removing the extreme capacity shortfalls.

Figure 36. Annual 99th percentile capacity shortfall, Base Scenario, with [number of instances] and (average shortfall)



Similar information is shown below in Figure 37 for the 99th-percentile of the number of instances of consecutive hours of capacity shortfall each year. Using 2029 as an example, there are 3,907 instances of capacity shortfall up to 50 hours long, and the average shortfall duration is seven hours. These numbers represent lowest 99% of all instances of capacity shortfall in 2029. The 99th percentile is used here to define all instances except for the most extreme outliers.

Figure 37. Annual 99th percentile hours of capacity shortfall, Base Scenario, with [number of instances] and (average consecutive hours)



A summary of the number of instances of a given capacity shortfall in 2029 and 2033 (key years where firm capacity is assumed to be removed from the system) is shown in Figure 38 and Figure 39, respectively, for the Base, Low Load, High Load and Land Constrained scenarios.

Figure 38. Histograms of capacity shortfall in 2029 grouped by scenario and shortfall magnitude

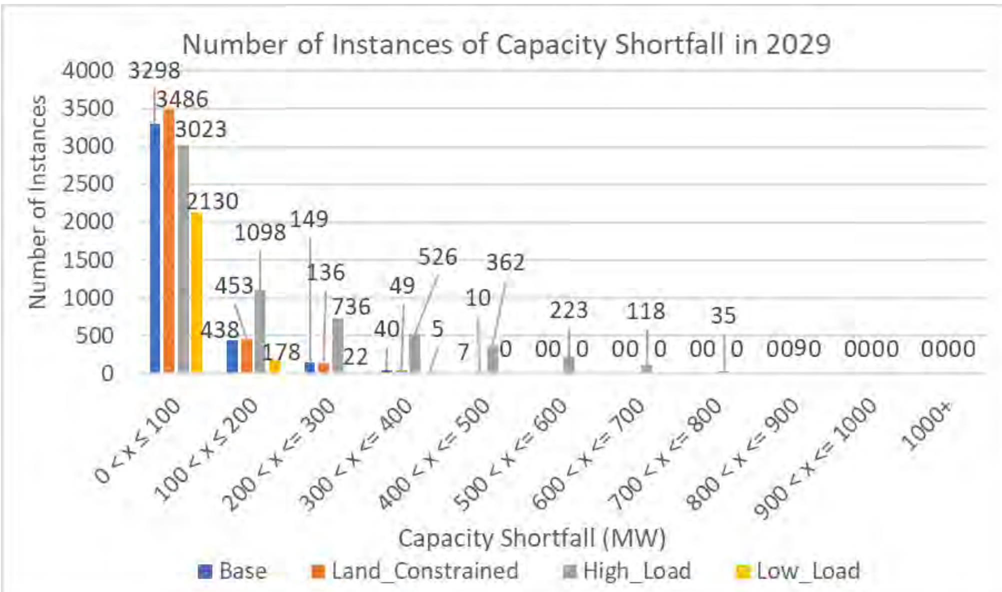
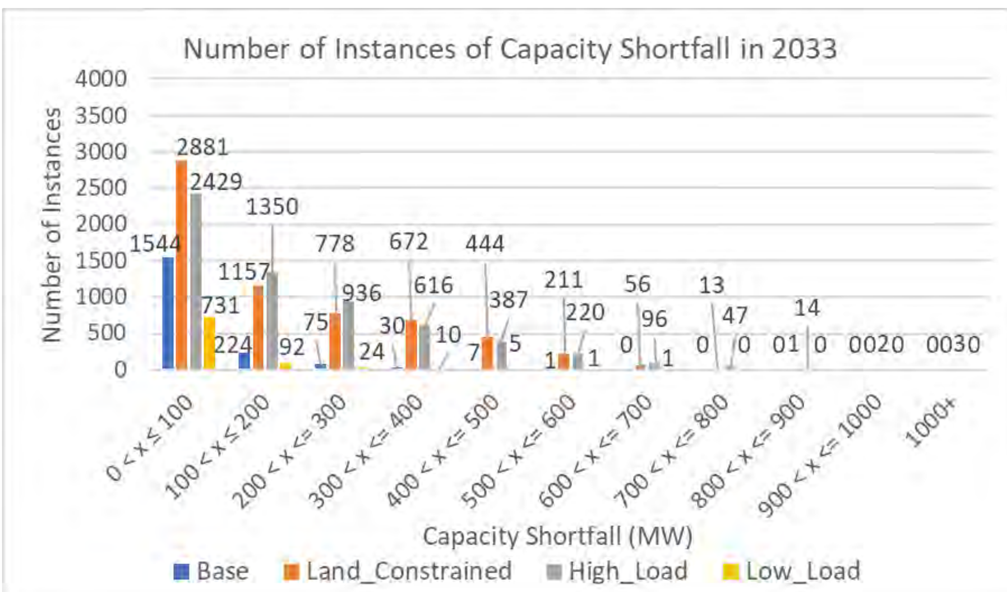


Figure 39. Histograms of capacity shortfall in 2033 grouped by scenario and shortfall magnitude



A summary of the number of instances of a given consecutive hours shortfall in 2029 and 2033 is shown in Figure 40 and Figure 41, respectively, for the Base, Low Load, High Load and Land Constrained scenarios.

Figure 40. Histograms of capacity shortfall in 2029 grouped by scenario and shortfall duration

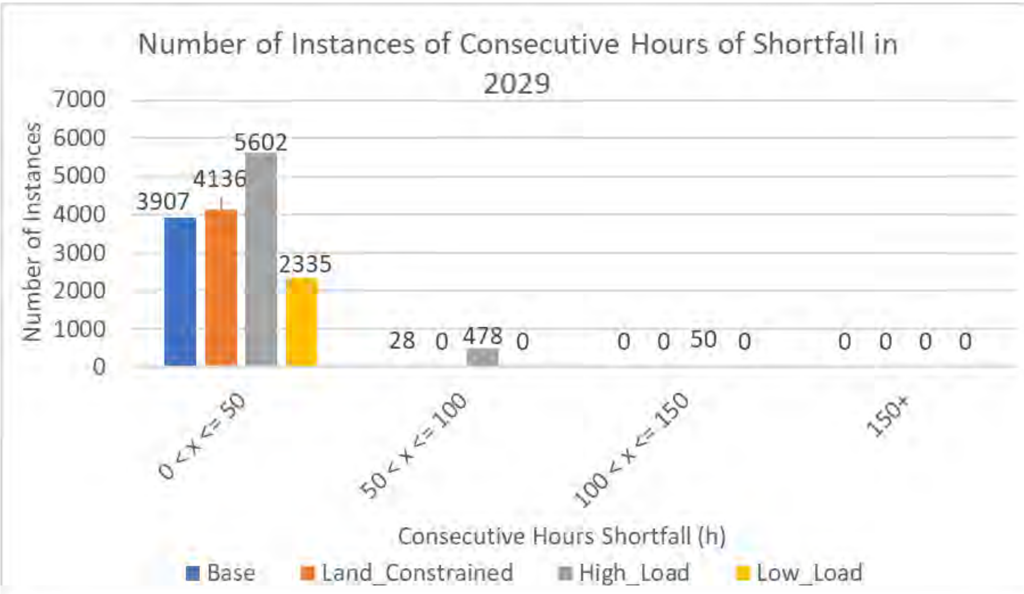
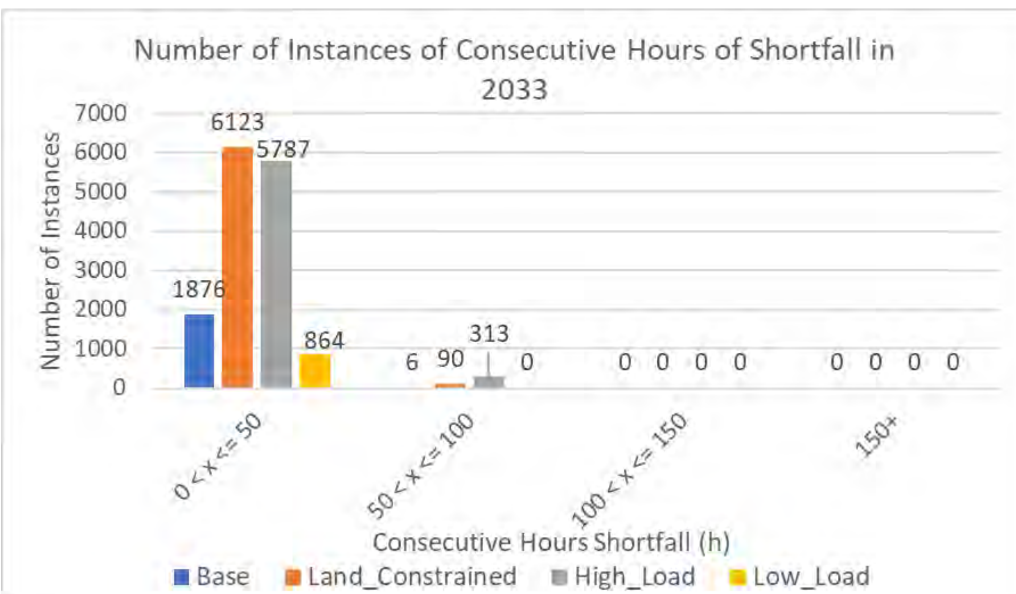


Figure 41. Histograms of capacity shortfall in 2033 grouped by scenario and shortfall duration



The High Load bookend scenario has higher capacity needs on a magnitude and duration basis because of the higher forecasted loads associated with increased EV uptake and reduced DER and EE uptake. This scenario provides useful information to inform how much additional capacity would be needed to provide further assurance that the system can reliably serve load amidst customer trends and state and federal policies that may drive EV adoption and thus increase load that Hawaiian Electric would need to serve. It also provides insight into the system needs should customer adoption of DER and EE fall short of projections that are embedded in the load forecast. Differences between the Base and other planning scenarios become more apparent once 170 MW of fossil-fuel generation is removed from service in 2029. Since the Land Constrained scenario does not allow for further onshore wind development and reduces the amount of solar development that can occur compared to the Base scenario, the number of hours of shortfall and capacity shortfall is higher in the Land Constrained scenario than the Base scenario.

6.4.1 ERM Sensitivity with Additional Generation Removals

An ERM sensitivity analysis was performed in PLEXOS using the Base resource plan shown in Figure 27, but in this scenario, the 208 MW KPLP was removed in 2029, and the largest Stage 2 project, 120 MW Mahi Solar, was removed. Since these are the two largest capacity firm generation and solar projects, respectively, a sensitivity was run to determine their impact on the ERM.

Similar to the other cases examined for ERM, the firm resources selected by RESOLVE were removed in the ERM analysis to determine the shortfall that any future firm resource addition would need to address. Shown below in Figure 42 is the number of instances of a given capacity shortfall each year and in Figure 43 is the number of instances of consecutive hours of capacity shortfall each year.

Figure 42. Annual 99th percentile capacity shortfall, Base_noKPLP_noMahi scenario, with [number of instances] and (average shortfall)

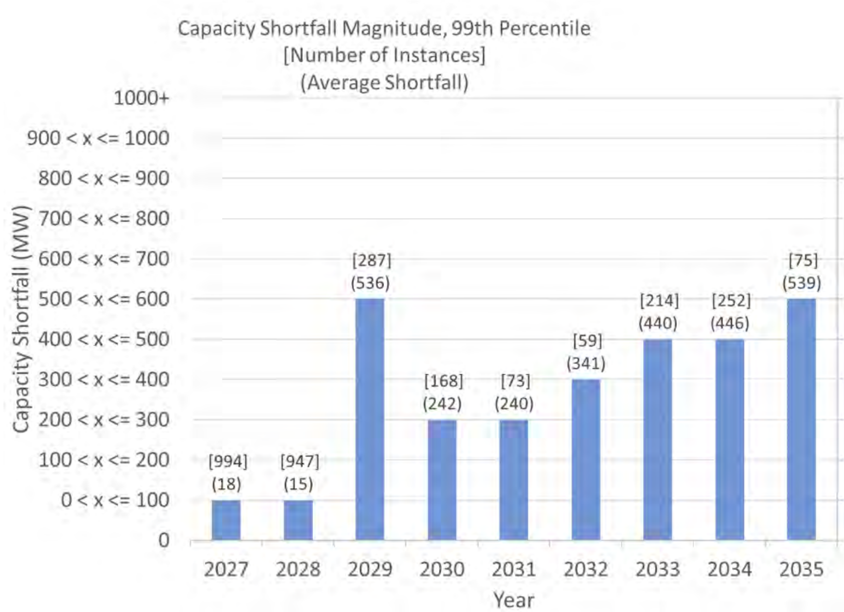
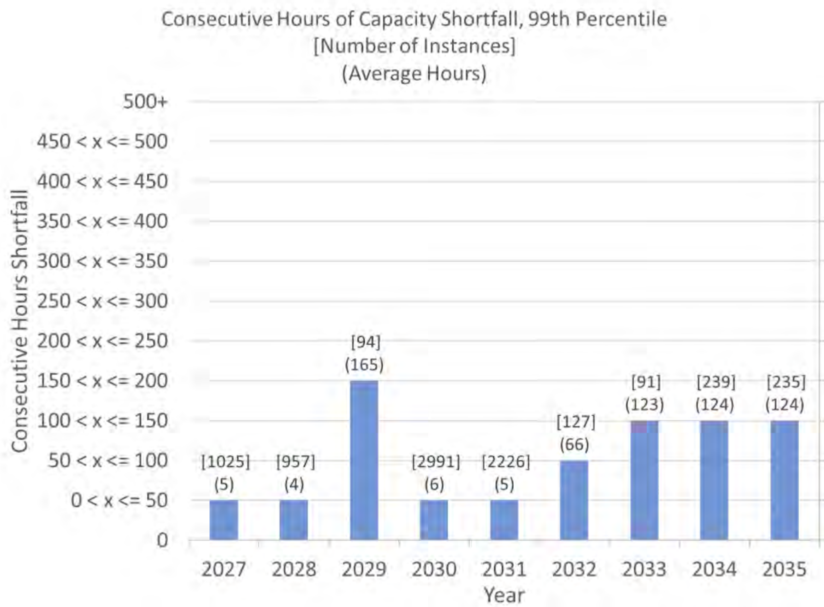


Figure 43. Annual 99th percentile hours of capacity shortfall, Base_noKPLP_noMahi scenario, with [number of instances] and (average shortfall duration)



In the Base case that removed KPLP and Mahi Solar from the resource plan, the removal of Mahi Solar does not appear to materially change the need as the capacity and duration in 2027 and 2028 is similar to the Base case. However, the removal of KPLP in this case dramatically increases the capacity and duration of the shortfalls from 2029. By comparing Figure 36 and Figure 42, it is evident that removal of KPLP and Mahi Solar increases the average capacity shortfall in 2029 by 294 MW, from 242 MW to 536 MW. By comparing Figure 37 and Figure 43, it is evident that removal of KPLP and Mahi Solar increases the average consecutive hours shortfall in 2029 by 158 hours, from 7 hours to 165 hours. This indicates that the removal of this large thermal generator has an outsized impact on future reliability.

Due to the amount of time needed to conduct a competitive procurement for a firm generation resource, 2029 is the earliest estimated date that a firm resource could be installed. In the Base_NoKPLP_NoMahi case, in 2029, 99% of the shortfall is less than 600 MW, and the average shortfall for all instances in the 500MW to 600MW range is 536MW.

Based on the analytical results, a firm thermal unit appears appropriate to fulfill the capacity needs identified in this analysis based on the long duration of the needs shown in the ERM analysis. In the Base_NoKPLP_NoMahi case, in 2029, 99% of the duration required is less than 200 consecutive hours and the average duration for all instances in the 150 to 200 consecutive hour range is 167 consecutive hours. The long-duration need is much longer than could be reasonably met with battery energy storage or other energy storage resources but could be met by a firm thermal resource with a renewable fuel supply.

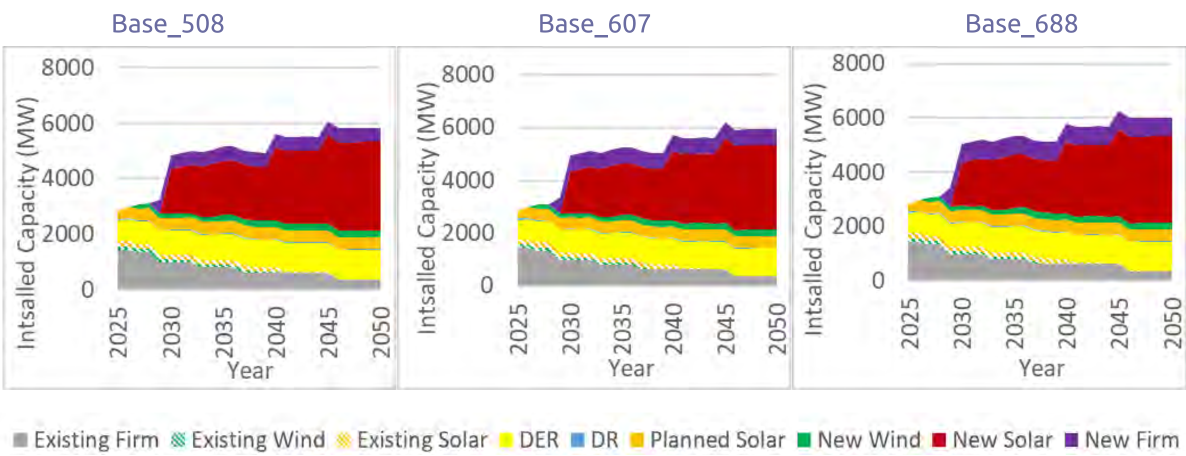
6.4.2 ERM Iteration to Validate Resource Adequacy Grid Needs

Hawaiian Electric performed an iteration of the ERM analysis to determine the ERM need. Based on the analysis where no new resources are added to the system, Hawaiian Electric tested firm capacity additions ranging from 500 to 700 MW and included firm fossil-fuel generation removals as indicated in the inputs and assumptions in years 2027, 2029 and 2033.

500 MW was determined based on the Base scenario 99th percentile showing capacity shortfalls between 200-300 MW (an average of 242 MW) and the sensitivity with KPLP removed showing capacity shortfalls between 500-600 MW (an average of 536 MW). The higher end target of 700 MW is based on year 2033 (with simulated removal of another 170 MW of firm fossil-fuel generation) that capacity shortfalls in the Land Constrained and High Load scenarios are seen in excess of 500 MW, before the assumed removal of the 208 MW KPLP plant. In other words, if KPLP is assumed to be in-service through the planning horizon, the ERM shortfalls fall between 300-500 MW. Under the assumption that KPLP is not in-service, shortfalls range between 500-700 MW. This section examines the ERM need based on these ranges to inform any potential capacity grid needs.

In the Base and Land Constrained cases, planned additions of thermal resource were added in 2029. These ERM scenarios add 508, 607, and 688 MW of firm generation (with Mahi Solar and KPLP removed). In the 508 case, 300 MW of combustion turbine and 208 MW of combined cycle were added. In the 607 case, 300 MW of combustion turbine, 208 MW of combined cycle, and 99 MW of internal combustion engine were added. In the 688 case, 300 MW of combustion turbine, 208 MW of combined cycle, and 180 MW of biomass were added. Shown below in Figure 44 is the installed capacity trend for various resource categories for the Base_508, Base_607 and Base_688 scenarios, respectively.

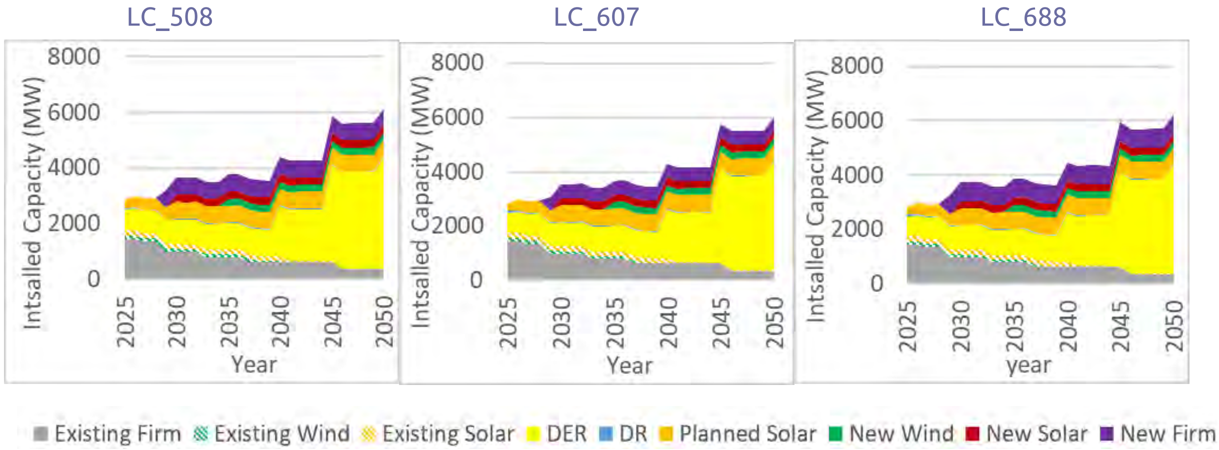
Figure 44. Installed capacity trends for resource categories by scenario



As the existing fossil-fuel firm generation in gray declines over time with the removal of existing thermal generating units from normal service over the planning period, the replacement thermal capacity of new renewable firm in purple is still much less than the variable renewables considered in the portfolio.

The same firm capacity was installed in the Land Constrained (LC) case. Shown below in Figure 45 is the installed capacity trend for various resource categories for the LC_508, LC_607 and LC_688 scenarios, respectively. The Land Constrained scenario, which limits the development of future grid-scale renewables, relies upon distributed solar in the later years of the planning horizon.

Figure 45. Installed capacity trends for resource categories by scenario



A summary of the number of instances of a given capacity shortfall in 2029 and 2033 is shown in Figure 46 and Figure 47, respectively, for the three different Base scenarios and three different Land Constrained scenarios.

Figure 46. Histograms of capacity shortfall in 2029 grouped by scenario and shortfall magnitude

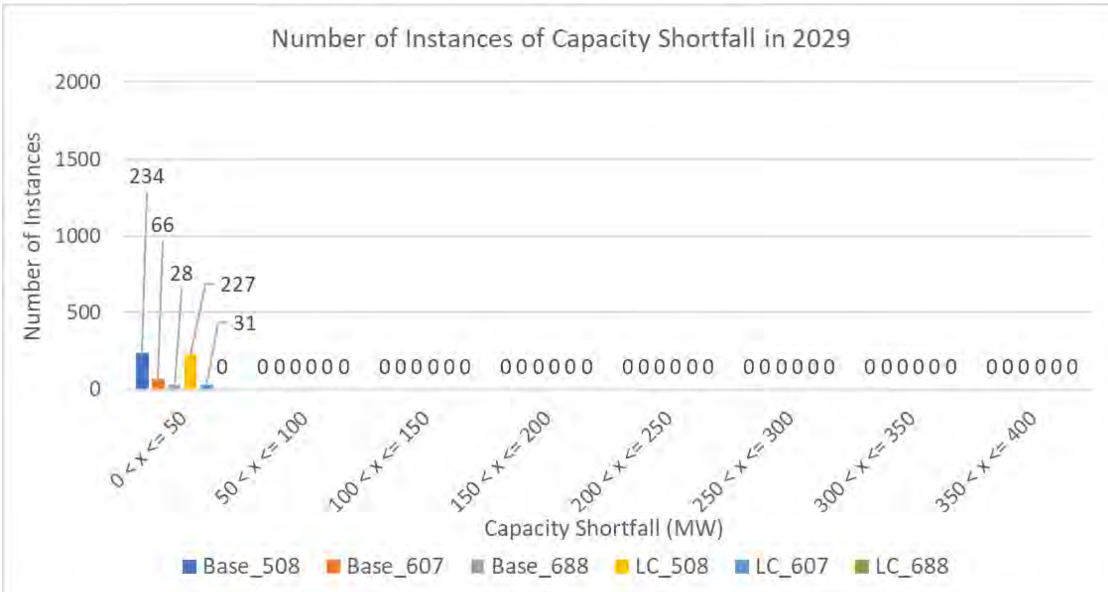
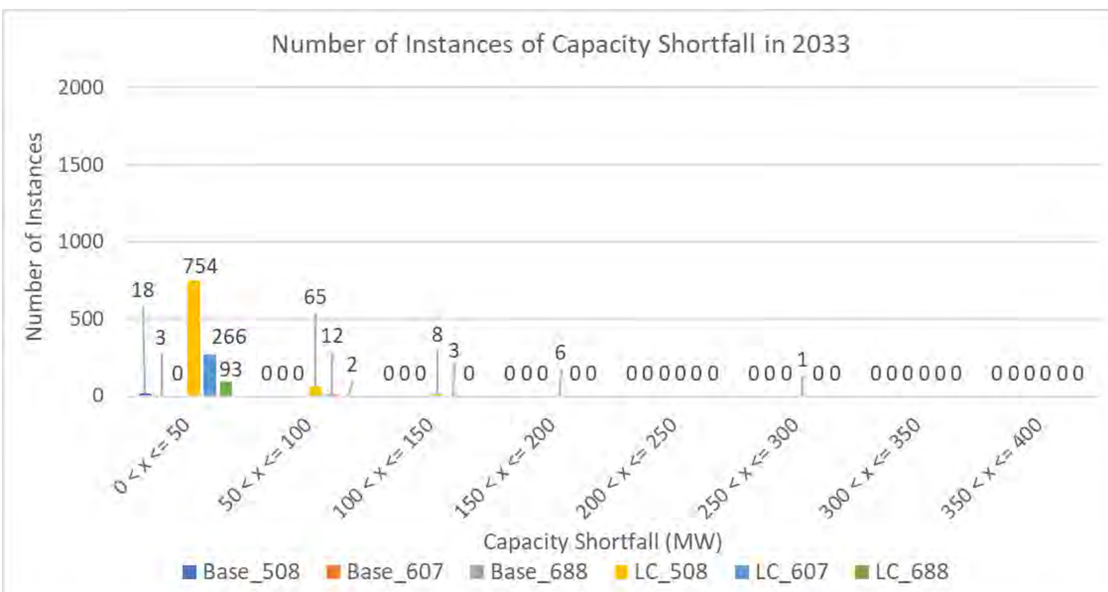


Figure 47. Histograms of capacity shortfall in 2033 grouped by scenario and shortfall magnitude



A summary of the number of instances of a given consecutive hours shortfall in 2029 and 2033 is shown in Figure 48 and Figure 49, respectively, for the three different Base scenarios and three different Land Constrained scenarios.

Figure 48. Histograms of capacity shortfall in 2029 grouped by scenario and shortfall duration

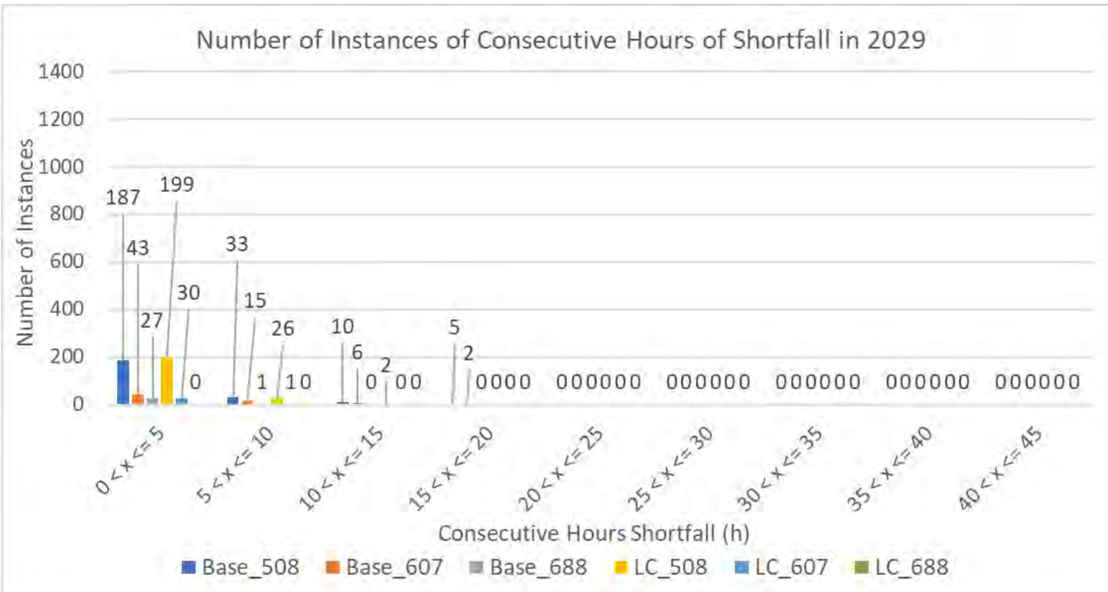
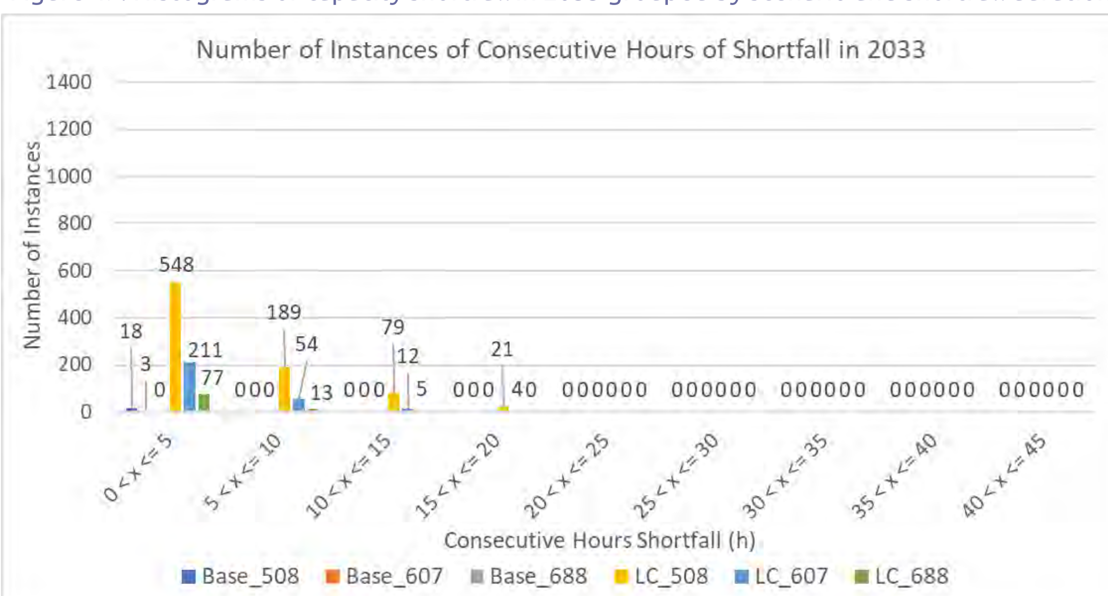


Figure 49. Histograms of capacity shortfall in 2033 grouped by scenario and shortfall duration



When the firm resource is added in 2029, the capacity shortfall and number of instances of shortfall decreases. Similarly, when the firm resource is added in 2029, the consecutive hours shortfall and number of instances of shortfall decreases. The Base scenario also has less shortfall, both in magnitude and frequency, than the Land Constrained scenario due to the higher amounts of renewables (wind and paired solar) added.

Shown below in Figure 50 is a detailed look of the capacity shortfall for the three different Base scenarios and three different Land Constraint scenarios in 2029. As expected, as the size of the firm capacity increases, there is less capacity shortfall.

Figure 50. Year 2029 hourly capacity shortfall. Base and Land Constrained scenarios

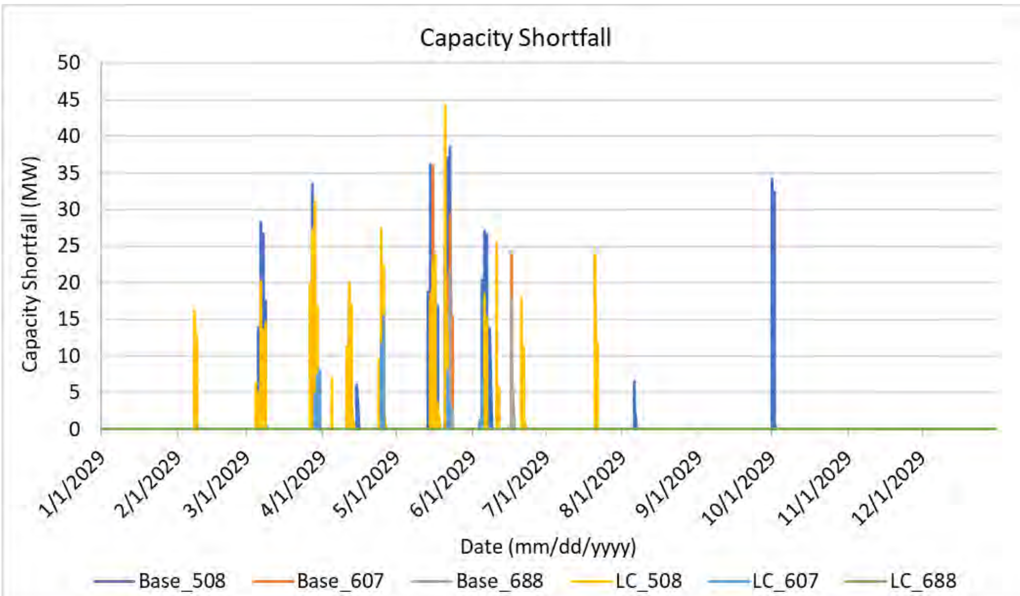


Figure 51 and Figure 52 are the dispatch for a high-renewable day in 2029 and low-renewable day in 2029, respectively. Note that this is the dispatch in the ERM analysis, and therefore, variable renewable production is defined by the HDC and is not representative of the dispatch of the new firm units during normal operation. As shown in Figure 51, even on a day with high renewable energy, the new firm generators are needed to meet capacity need. This becomes even more evident on the low-renewable days shown in Figure 52. Even with the large number of renewables added in 2030, the new firm generators are still needed to help meet the capacity requirement as shown in Figure 51 and Figure 52.

Figure 51. Daily chart – ERM simulation – Base_508 scenario– High renewable day

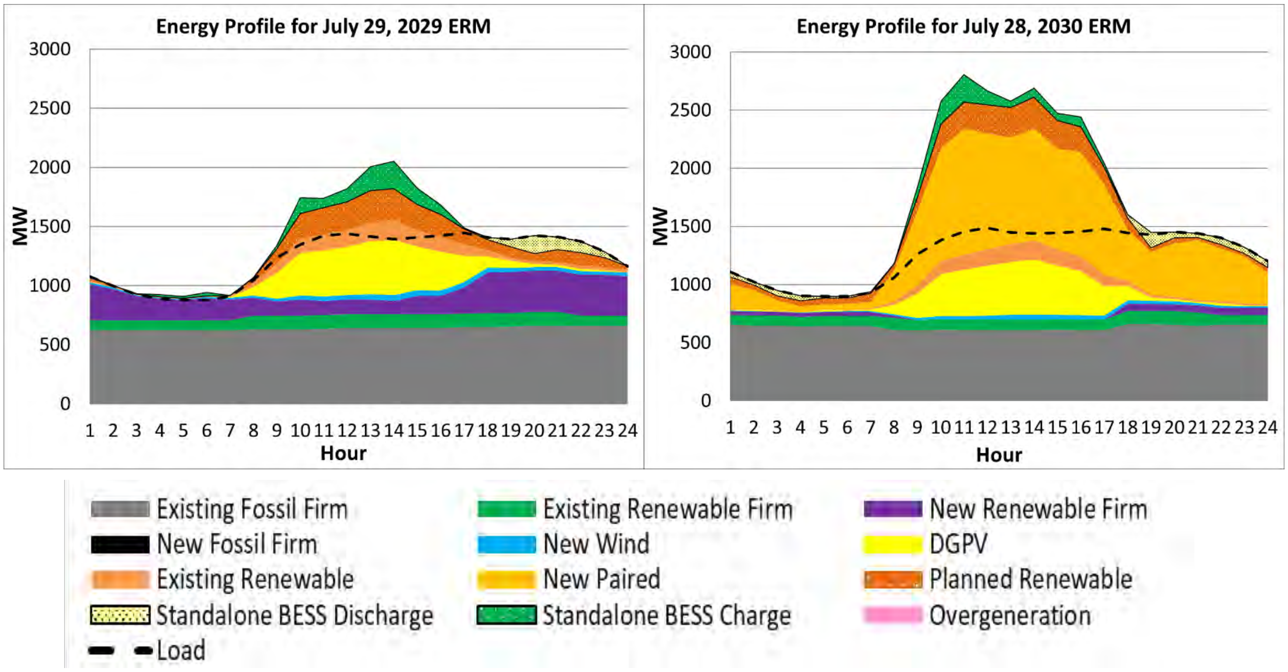
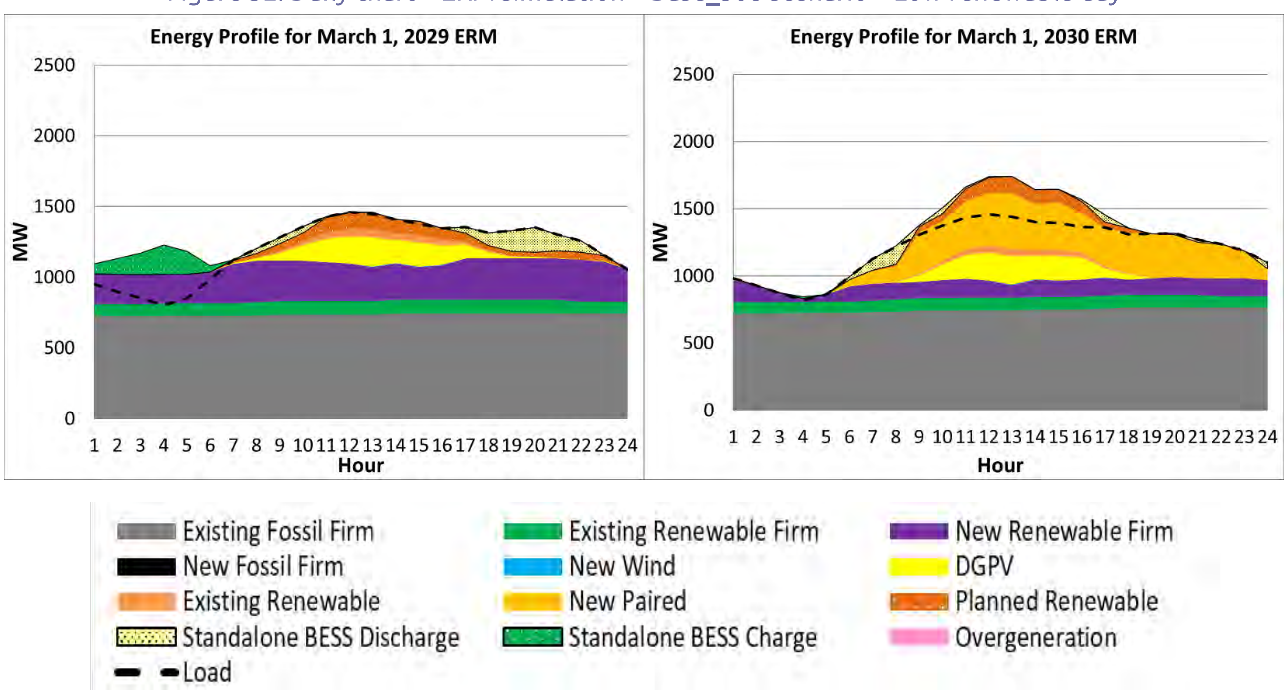


Figure 52. Daily chart – ERM simulation – Base_508 scenario – Low renewable day



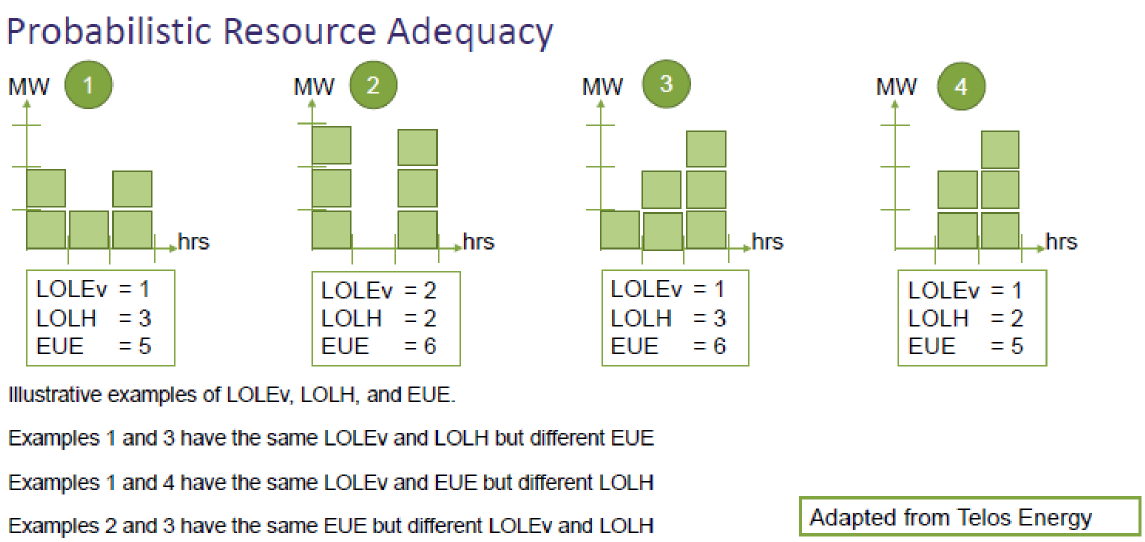
6.5 Probabilistic Resource Adequacy Analysis

This section provides extensive probabilistic resource adequacy analysis (as endorsed by the TAP) to validate the reliability of the resource portfolios generated by RESOLVE in Section 6.3.2. Numerous sensitivities were modeled to test resource adequacy uncertainty and risks associated with energy storage duration, distributed energy resources/demand response, amount of grid-scale solar that may be built, and acceleration/delay of existing fossil-fuel generation, among others.

The probabilistic analysis identified year 2029 as the target year for future firm renewable generation. The analysis used five weather years and 50 thermal generator outage samples. Specifically, PV reliability was based on five years of NREL data, from 2015 through 2019, which was provided as part of the NREL Resource Potential study. Wind reliability was based on historical measured data from existing wind plants for the same five years. DER used historical monthly capacity factor measurements also from the same five years. Thermal generators had 50 random outage samples with each sample modeled as an independent production simulation. A total of 250 (50 outage samples per year for five weather years) samples were modeled.

Four metrics were reported and used to compare the various cases. Loss of Load Expectation (LOLE) is the number of days per year where there is unserved energy. The unserved energy within the day is quantified as Loss of Load Events (LOLEv) defined as the number of unserved energy events per year. The difference between LOLE and LOLEv is that multiple unserved energy events can occur in a single day. Loss of Load Hours (LOLH) is the number of hours of unserved energy. One unserved energy event can last for one or more hours, and therefore, an LOLE of 0.1 days/year is not necessarily the same result as an LOLH of 2.4 hours/year. Expected Unserved Energy (EUE) is the amount of unserved energy. Examples of the various metrics and their interrelationship were shared in the Stakeholder Technical Working Group meeting on June 9, 2022 and recapped below in Figure 53. As shown, while the day has unserved energy, the magnitude, duration, and frequency of that unserved energy affects the various metrics.

Figure 53. Probabilistic resource adequacy metrics examples



The typical North America guideline for LOLE is 0.1 days per year. Belgium, France, Great Britain, and Poland have an LOLH standard of a maximum of 3 hr/yr. AEMO has a reliability standard of a maximum expected unserved energy of 0.002% of total energy demand, which would equate to a target maximum expected unserved energy of 0.137 GWh using Oʻahu's 2029 forecasted energy demand.

This range in LOLE (≤0.1), LOLH (≤3hrs), and EUE (≤0.137 GWh) provides a useful frame of reference when evaluating resource plans that consider different additions of variable renewables and thermal resources. Stricter reliability thresholds may be warranted to address generation resilience on isolated island grids as high impact, low frequency events increase in frequency.

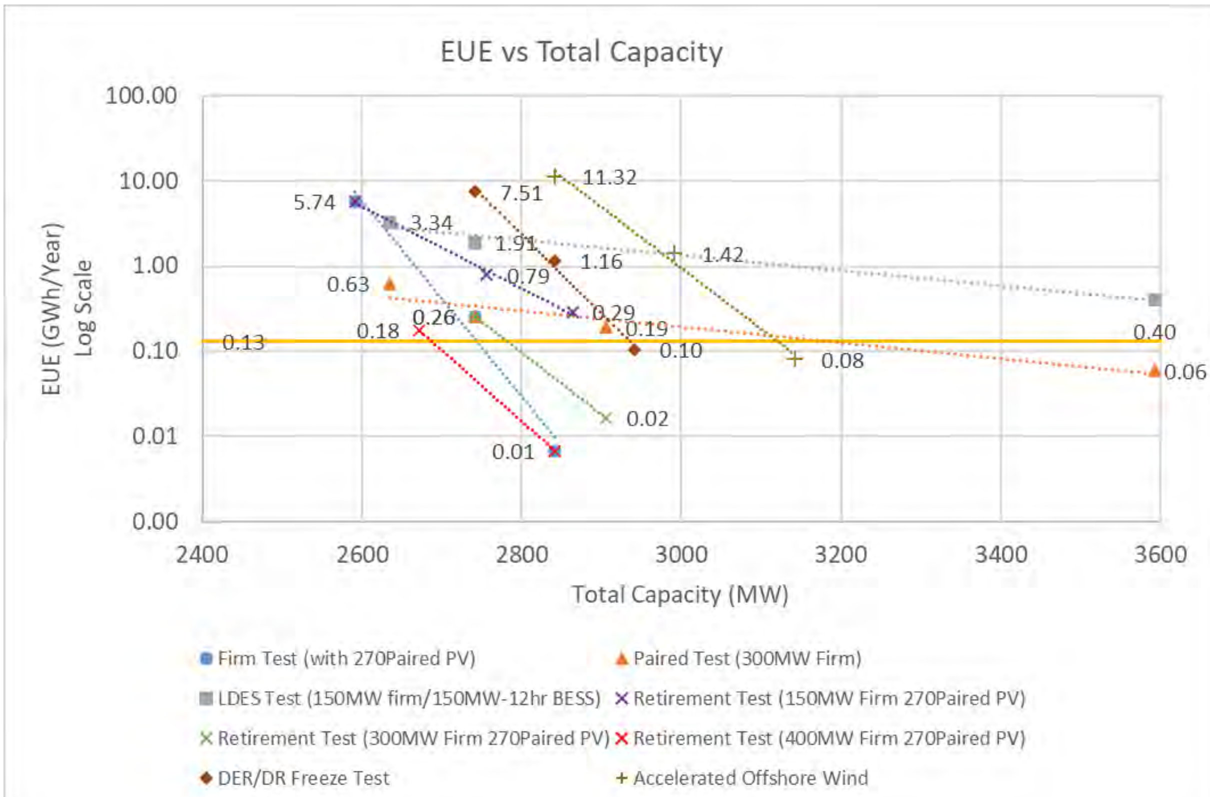
A probabilistic analysis was performed on the following cases and presented to the TAP through the resource adequacy subgroup for feedback.

- Recent Outage Rates Trend Analysis: These cases use the same resource plans from the above cases but update the outage rates for the existing thermal generators to the latest outage forecast based on the most recent trends. These higher outage rates are reflected in the *March 2022 Inputs and Assumptions*. The cases without the higher outage rates used the *August 2021 Inputs and Assumptions* which were based on a longer run historical outage rate for each unit. This analysis will show the impact that the deteriorating performance of the existing generators has on the probabilistic metrics. Based on feedback from the TAP, all subsequent analysis listed below assume the recent, higher outage rates.
- Firm Generation Sensitivity: These cases start with the Base case with 270 MW of paired PV and 0 MW of land-based wind and adjust the amount of firm generation installed. 270 MW paired PV was chosen since it is the approximate size of the Stage 3 RFP target and the size of the Land Constrained scenario. This analysis shows the impact that the size of the new firm generation has on the probabilistic metrics.
- Firm Capacity Based on Paired Renewable: These cases start with the Base case with different amounts of paired renewables and estimate how much firm generation is needed for the EUE to meet the reliability target based on a curve fit of the results.
- Long-Duration Energy Storage: These cases compare runs with 300 MW of new firm generation with cases that have 150 MW of new firm generation and 150 MW of new 12-hour energy storage. This will show the impact that substituting firm generation with long-duration energy storage has on the probabilistic metrics.
- Deactivation Sensitivity: These cases take the Base case with 270 MW of paired PV and add either 150 MW, 300 MW, or 400 MW of new firm generation to look at how the reliability metrics may be affected by the removal from service schedule.
- Load Sensitivity: These cases look at how the reliability metrics are affected by the load forecast and amount of new firm generation, as well as, how the removal from service schedule may need to be adjusted to ensure a reliable system.
- DER/DR Freeze Sensitivity: These cases froze the DER forecast at the end of 2020, EE forecast at the end of 2021, and assumed all EV charging was unmanaged. This analysis shows how the forecast for these customer resources affect the new firm generation needed.
- Additional DER/DR Resource: These cases examine the impact of adding additional 2-hour energy storage on the reliability metrics.

- Accelerated Offshore Wind: These cases look at the impact of adding 400 MW of offshore wind on the reliability metrics and whether adding offshore wind impacts the new firm generation target.
- Planning for Extreme Events: These cases study the impact that a forced outage of 438 consecutive hours on various resource types has on the probabilistic metrics to show whether firm generation provides the same value as variable generation during long duration outages.

Shown below in Figure 55 is a summary of most runs that employed the Base forecast. As shown, the slope of the blue line is steeper than the slope to the orange line indicating that increasing firm generation has greater effect on lowering EUE than increasing paired PV. The figure also shows most cases that meet the EUE reliability target have at least 300MW of firm generation along with additional capacity from another resource.

Figure 54. EUE versus total capacity for various probabilistic analysis using the Base forecast



Shown below in Figure 55 is a summary of all the base cases run which met all three-reliability metrics used in other jurisdictions (i.e., LOLE ≤ 0.1, LOLH ≤ 3hrs, and EUE ≤ 0.137 GWh). In addition, cases which were within twice the reliability metrics on all three (i.e., LOLE ≤ 0.2, LOLH ≤ 6hrs, and EUE ≤ 0.274 GWh) are also shown.

Figure 55. Summary of cases where LOLE, LOLH, and EUE are all within twice the reliability targets of other jurisdictions

Year 2029	Existing Firm (MW)	New Firm (MW)	New Paired PV (MW)	New Onshore Wind (MW)	New Offshore Wind (MW)	LOLE (Days / Yr)	LOLEv (Event / Yr)	LOLH (Hours / Yr)	EUE (GWH / Yr)	Relative Cost ($000)
Base_300_270PVB_0Wd_170HE_Mar22Out	1,135	300	270	0	0	0.09	0.16	0.22	0.02	1,593,167
Base_400_270PVB_0Wnd_Mar22Out	970	400	270	0	0	0.04	0.05	0.09	0.01	1,743,273
Base_300_958PVB_Mar22Out	970	300	958	163	0	0.08	0.20	0.37	0.06	1,419,308
Base_200_1600PVB_Mar22Out	970	200	1,600	163	0	0.08	0.18	0.34	0.09	1,421,125
Base_300_1600PVB_Mar22Out	970	300	1,600	163	0	0.01	0.04	0.07	0.02	1,441,373
Base_250_958PVB_Mar22Out	970	250	958	163	0	0.18	0.42	0.87	0.16	1,412,985
Base_300_270PVB_400OSW_Mar22Out	970	300	270	0	400	0.18	0.34	0.74	0.08	1,335,359

As shown above in Figure 55, a majority of cases require at least 300 MW of firm generation to meet or come close to meeting all three reliability metrics. While there are some cases which require less than 300 MW of new firm generation, those cases require a substantial amount of paired renewables to meet the reliability metrics. To put into context, the Stage 1 and 2 projects that are currently remaining have an aggregate capacity of around 230 MW. Adding 250 MW of new firm generation, would require approximately 958 MW of additional paired PV, or about four times the capacity that's currently expected from Stage 1 and 2. Adding 200 MW of new firm generation (or alternatively 300 MW with accelerated fossil-fuel deactivations), would require approximately 1,600 MW of additional paired PV, or almost seven times the capacity that's currently expected from Stage 1 and 2. A balance must be struck between the need to address the existing firm generation fleet and the time to work with communities, land owners, and developers to realize higher amounts of solar.

Also shown in Figure 55 is the estimated cost in 2029 stated as revenue requirements. This cost includes revenue requirements for fuel, variable and fixed O&M, capacity and energy payments for IPP, and capital. This provides directional costs in a year where both new renewable firm and variable generation are added, taking into account the operating costs with a full year of the simulated resource portfolio. There are five resource portfolios tested that have a cost at or below approximately $1.4B, and more than half of those cases had 300 MW of new firm generation. While there is one portfolio which has 1,600 MW of solar, 163 MW of onshore wind, and only 200 MW of new renewable firm generation, as stated earlier, given the significant amount of hybrid solar needed by 2029, it would be prudent to procure at least 300 MW. If at some point in the future the system conditions allow for additional retirement of fossil-fuel generation, Hawaiian Electric may consider such options to reduce costs.

Shown above in Figure 55, Base_300_270PVB_0Wd_170HE_Mar22Out, achieves an LOLE of 0.09, which is close to the US Mainland standard. Using this case, shown below in Figure 56 is the sum of unserved energy based on the month and hour. As shown, most of the unserved energy is concentrated in the months of April and May during the early morning and evening hours. Whether new resources can further improve reliability will depend in part on their availability during these months and hours.

Figure 56. Unserved energy for 250-sample mean

Hours Beginning	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	0.00	0.00	0.00	0.45	0.23	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1	0.00	0.00	0.00	0.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	1.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.65	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	0.00	0.00	0.00	0.17	0.53	0.00	0.00	0.00	0.00	0.00	0.00	0.00
18	0.00	0.00	0.00	0.15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
19	0.00	0.00	0.00	2.96	0.56	0.00	0.00	0.00	0.00	0.00	0.00	0.00
20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
21	0.00	0.00	0.00	1.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
22	0.00	0.00	0.00	4.43	0.38	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	3.41	0.21	0.00	0.00	0.00	0.00	0.00	0.00	0.00

In response to TAP feedback, for a given set of renewable additions, firm generation was incremented to create a relationship between new firm generation additions and EUE. Using this relationship, based on the amount of renewable addition, the amount of new firm generation needed to meet the 0.002% EUE threshold could be estimated.

The following variable renewable additions were considered:

- 270 MW PV (Land constrained limit for new grid-scale PV development, land-based wind not available)
- 958 MW PV (15% slope limit for new grid-scale PV development) and 163 MW onshore wind (remaining NREL technical potential)

- 1,600 MW (New paired PV selected by RESOLVE in the Base case in year 2030) and 163 MW onshore wind (remaining NREL technical potential)

Figure 57. Expected firm thermal addition needed to satisfy EUE reliability target

Year 2029	Existing Firm (MW)	New Firm (MW)	New Paired PV (MW)	New Onshore Wind (MW)	New Offshore Wind (MW)	LOLE (Days / Yr)	LOLEv (Event / Yr)	LOLH (Hours / Yr)	EUE (GWH / Yr)
Curve Fit – 270PVB	970	300	270	0	0	N/A	N/A	N/A	0.137
Curve Fit – 958PVB	970	255	958	163	0	N/A	N/A	N/A	0.137
Curve Fit – 1600PVB	970	175	1,600	163	0	N/A	N/A	N/A	0.137

Applying a curve fit to these cases and targeting 0.002% EUE or 137 MWh yielded a range of new firm thermal capacity from 175 – 300 MW. The EUE reliability standard was applied here based on feedback from the TAP that EUE should be given serious consideration given the high penetration of energy limited and weather dependent resources on the system. Based on the probabilistic analyses conducted herein, LOLE appears to be the most stringent standard to meet so curve fitting to an LOLE of 0.1 day/year instead would likely yield a higher firm capacity addition.

Above 270 MW of PV, further onshore development may be limited based on stakeholder feedback on available potential, and if greater capacities can be developed, REZ infrastructure will be required. To ensure near-term reliability needs can continue to be met, a minimum of 300 MW of firm generation may be needed.

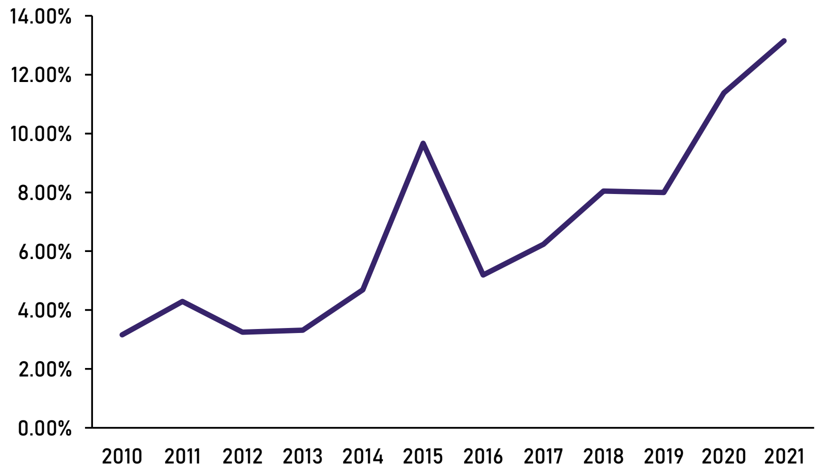
As demonstrated by the Base case simulated in the RESOLVE capacity expansion optimization, low cost renewable dispatchable generation should be the first option. The Stage 3 procurement is based on the 2027 renewable energy optimized by RESOLVE and the limits which the existing transmission system can accommodate. A forthcoming procurement as part of the IGP process will include resources that may take longer to develop through collaboration with communities and project partners. These efforts will work towards increasing low-cost renewables on the system in future years. The 300 MW of new renewable firm generation by 2029 with continued pursuit of low-cost renewable energy is the least-regrets path forward to reduce risks associated with worsening trend of fossil-fuel generator reliability, development of low-cost renewable projects, and the lead time to build renewable firm generation. In the event system conditions allow for additional removal of fossil-fuel generation (i.e., future years where 300 MW of new firm generation is added along with upwards of 1,600 MW of hybrid solar), Hawaiian Electric may further consider accelerated retirements of other fossil-fuel generators.

Additional details on the probabilistic analysis can be found in the following sections. The remaining part of this section disucsses the in-depth analysis performed to support the conlcusions and summary discussed above.

6.5.1 Recent Outage Trend in Current Firm Generation

The historical weighted equivalent forced outage rate for the generating fleet is reported annually as part of the Key Performance Metrics, and it has increased over the past decade, as shown in Figure 58.

Figure 58. Weighted forced outage rate of Hawaiian Electric generators, 2010-2021



An analysis was performed which looked at the impact of higher outage rates on the probabilistic metrics. The outage rates were recently updated to reflect latest trends and were provided in the PUC approved *March 31, 2022 Integrated Grid Planning Inputs and Assumptions*. Shown below in Figure 59 is a comparison of the 2029 outage rates assumed in the initial set of runs, which was provided in August 2021.

Figure 59. Maintenance outage rates and forced outage rates provided in August 2021 and March 2022 Inputs and Assumptions filings

	Maintenance Outage Rate (%)		Forced Outage Rate (%)	
Generator	August 2021	March 2022	August 2021	March 2022
Waiau 5	1.9	11.5	5.0	15.0
Waiau 6	1.9	11.5	5.0	15.0
Waiau 7	13.4	32.0	4.5	13.0
Waiau 8	21.1	11.5	4.5	13.0
Waiau 9	3.8	3.8	4.0	4.0
Waiau 10	3.8	3.8	4.0	4.0
Kahe 1	3.8	11.5	4.5	13.0
Kahe 2	3.8	11.5	4.5	13.0
Kahe 3	13.4	11.5	4.5	13.0
Kahe 4	3.8	11.5	4.5	13.0
Kahe 5	1.9	11.5	5.0	10.0
Kahe 6	13.4	11.5	5.0	10.0
CIP CT-1	3.8	3.8	3.0	4.0
H-POWER	0.0	0.0	3.0	3.0
Airport DSG	1.9	1.9	5.0	5.0
Schofield	1.9	1.9	2.0	2.0

The following scenarios modeled the updated outage rates to match the March 2022, *IGP Inputs and Assumptions* filing.

- Base_508_Staggered_Mar22Out
- Base_688_Staggered_Mar22Out
- Base_Accel_Mar22Out
- Base_Accel_508_Staggered_Mar22Out
- LC_508_Staggered_Mar22Out
- LC_688_Staggered_Mar22Out
- LC_Accel_Mar22Out
- LC_Accel_508_Staggered_Mar22Out

Shown below in Figure 60 is the capacity of resources in 2029 for the Base cases. The capacity of resources in 2029 for the Land Constrained cases is shown in Figure 61.

Figure 60. Probabilistic analysis - resource capacity summary, year 2029. Recent outage trend sensitivity, Base cases

Year 2029	Existing	Base_508 Staggered	Base_688 Staggered	Base_Accel	Base_Accel 508 Staggered
Existing Firm	1,729	970	970	970	970
Existing PV	188	188	188	188	188
Existing Wind	123	123	123	123	123
CBRE	0	185	185	185	185
Stage 1 Hoohana / Mililani / Waiawa / West O'ahu	0	139.5	139.5	139.5	139.5
Stage 2 Barbers Point / Kupono / Mountain View / Waiawa2	0	94	94	94	94
Future PV	0	0	0	1,577	1,577
Future Wind	0	163	163	163	163
Future Firm Units	0	300 MW (6-50 MW CT)	480 MW (6-50 MW CT 9-20 MW Biomass)	0	300 MW (6-50 MW CT)
Total	**2,040**	**2,163**	**2,343**	**3,440**	3,740
Stage 1 BESS	0	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh
Stage 2 BESS (incl. Kapolei BESS)	0	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh
Future BESS	0	287 MW / 539 MWh	287 MW / 539 MWh	1,956 MW / 5,174 MWh	1,956 MW / 5,174 MWh
Total	**0 MW / 0 MWh**	**705 MW / 2,165 MWh**	**705 MW / 2,165 MWh**	**2,374** MW / 6,800 MWh	**2,374 MW / 6,800 MWh**

Figure 61. Probabilistic analysis - resource capacity summary, year 2029. Recent outage trend sensitivity, Land Constrained cases

Year 2029	Existing	LC 508 Staggered	LC 688 Staggered	LC Accel	LC Accel 508 Staggered
Existing Firm	1,729	970	970	970	970
Existing PV	188	188	188	188	188
Existing Wind	123	123	123	123	123
CBRE	0	185	185	185	185
Stage 1 Hoohana / Mililani / Waiawa / West O'ahu	0	139.5	139.5	139.5	139.5
Stage 2 Barbers Point / Kupono / Mountain View / Waiawa2	0	94	94	94	94
Future PV	0	0	0	270	270
Future Wind	0	0	0	0	0
Future Firm Units	0	300 MW (6-50 MW CT)	480 MW (6-50 MW CT 9-20 MW Biomass)	0	300 MW (6-50 MW CT)
Total	**2,040**	**2,000**	**2,180**	**1,970**	**2,270**
Stage 1 BESS	0	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh
Stage 2 BESS (incl. Kapolei BESS)	0	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh
Future BESS	0	232.5 MW / 437 MWh	232.5 MW / 437 MWh	584 MW / 857 MWh	584 MW / 857 MWh
Total	**0 MW /** 0 MWh	**651 MW / 2,063 MWh**	**651 MW / 2,063 MWh**	**1,002** MW / 2,483 MWh	**1,002** MW / 2,483 MWh

Shown below in Figure 62 and Figure 63 are the impact that the higher outage rates have on the reliability metrics discussed earlier (noted by '_Mar22Out') compared to the previous outgae rates used in the August 2021 Inputs and Assumptions. The higher outage rates result in unserved energy, even in the cases where 500 MW of new firm generation is added or the 2030 renewables are accelerated to 2029. Increasing renewables on the system will likely increase the stress on the existing thermal generators and cause higher outage rates in the future.

Figure 62. Probabilistic analysis results summary, year 2029. Recent outage trend sensitivity, Base cases

	New Firm Generation (MW)	LOLE (Days/Year)	LOLEv (Events/Year)	LOLH (Hours/Year)	EUE (GWH/Year)
Existing (2021)	0	1.18	1.30	2.90	0.13
Base_508_Staggered	300	0.22	0.38	0.86	0.07
Base_688_Staggered	480	0.00	0.00	0.00	0.00
Base_508_Staggered_ Mar22Out	300	1.30	2.19	5.98	0.63
Base_688_Staggered_ Mar22Out	480	0.04	0.06	0.17	0.02
Base_Accel	0	0.52	1.05	2.01	0.44
Base_Accel_508_Staggered	300	0.00	0.00	0.00	0.00
Base_Accel_Mar22Out	0	2.08	4.36	8.40	2.03
Base_Accel_508_Staggered _Mar22Out	300	0.03	0.07	0.10	0.02

Figure 63. Probabilistic analysis results summary, year 2029. Recent outage trend sensitivity, Land Constrained cases

Year 2029	New Firm Generation (MW)	LOLE (Days/Year)	LOLEv (Events/Year)	LOLH (Hours/Year)	EUE (GWH/Year)
Existing (2021)	0	1.18	1.30	2.90	0.13
LC_508_Staggered	300	0.30	0.49	1.11	0.09
LC_688_Staggered	480	0.00	0.00	0.00	0.00
LC_508_Staggered_ Mar22Out	300	2.36	4.05	11.14	1.16
LC_688_Staggered_ Mar22Out	480	0.03	0.05	0.08	0.00
LC_Accel	0	29.55	56.92	159.10	22.16
LC_Accel_508_Staggered	300	0.14	0.28	0.48	0.04
LC_Accel_Mar22Out	0	72.82	146.28	460.36	69.81
LC_Accel_508_Staggered _Mar22Out	300	1.32	2.38	5.35	0.56

The results of higher outage rate sensitivities highlight the reliability risk of continuing to run the existing fossil-fuel generation and failing to procure replacement resources. In a Land Constrained future, more than 300 MW of firm renewable energy will be needed to attain a LOLE within the target range.

6.5.2 Firm Generation Sensitivity

Using the latest outage rates, the TAP was interested to see how the metrics are affected by the size of the new firm generation. Therefore, the following scenarios were tested.

- Base_150_270PVB_0Wnd_Mar22Out
    - Base case with 3-50MW CT generators added in 2029, 270 MW PV+ BESS, and 0 MW onshore wind.
    - 270 MW paired PV is the approximate size of the Stage 3 RFP target and limit on the Land Constrained case. The paired BESS was assumed to have 3-hour duration, which is the same size as the paired BESS chosen by RESOLVE as the optimal amount. Land-based or onshore wind was removed due to land use and community acceptance concerns.

- Base_300_270PVB_0Wnd_Mar22Out
    - Base_150_270PVB_0Wnd_Mar22Out with 6-50MW CT generators added in 2029 instead of 3-50MW CT generators.

- Base_400_270PVB_0Wnd_Mar22Out
    - Base_150_270PVB_0Wnd_Mar22Out with 8-50MW CT generators added in 2029 instead of 3-50MW CT generators.

Shown below in Figure 64 is the capacity of resources in 2029 for these cases.

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Resource Grid Needs Analysis

Figure 64. Probabilistic analysis - resource capacity summary, year 2029. New Firm Generation sensitivity

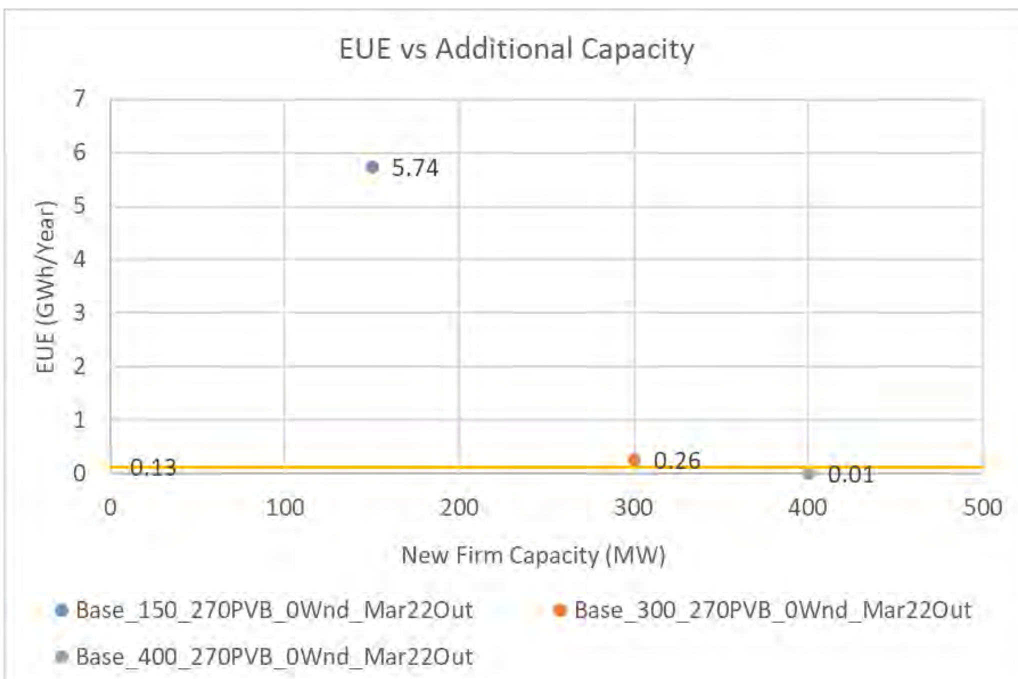
Year 2029	Existing	Base_150_270PVB_0Wnd_ Mar22Out	Base_300_270PVB_0Wnd_ Mar22Out	Base_400_270PVB_0Wnd_ Mar22Out
Existing Firm	1,729	970	970	970
Existing PV	188	188	188	188
Existing Wind	123	123	123	123
CBRE	0	185	185	185
Stage 1 Hoohana / Mililani / Waiawa / West O'ahu	0	139.5	139.5	139.5
Stage 2 Barbers Point / Kupono / Mountain View / Waiawa2	0	94	94	94
Future PV	0	270	270	270
Future Wind	0	0	0	0
Future Firm Units	0	150 MW (3-50 MW CT)	300 MW (6-50 MW CT)	400 MW (8-50 MW CT)
Total	**2,040**	**2,120**	**2,270**	**2,370**
Stage 1 BESS	0	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh
Stage 2 BESS (incl. Kapolei BESS)	0	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh
Future BESS	0	557 MW / 1,349 MWh	557 MW / 1,349 MWh	557 MW / 1,349 MWh
Total	**0 MW / 0 MWh**	975 MW / 2,975 MWh	975 MW / 2,975 MWh	975 MW / 2,975 MWh

Shown below in Figure 65 is the impact that the new firm generation capacity has on the various reliability metrics discussed earlier. Shown in Figure 66 is the relationship between the new firm generation capacity and EUE. As expected, as the size of the new firm generation increases, the reliability metrics improves. The results also show that with the latest outage rates, 300MW of new firm generation will not be adequate to meet the reliability targets; at least 400 MW of new firm generation will be needed. As the existing firm generation gets older and is operated under more extreme conditions, it is likely that the outage rates will increase further, making the need for at least 400MW of firm generation more likely.

Figure 65. Probabilistic analysis - results summary, year 2029. New Firm Generation sensitivity

Year 2029	New Firm Generation (MW)	LOLE (Days/Year)	LOLEv (Events/Year)	LOLH (Hours/Year)	EUE (GWH/Year)
Existing (2021)	0	1.18	1.30	2.90	0.13
Base_150_270PVB_0Wnd_Mar22Out	150	9.25	17.75	42.42	5.74
Base_300_270PVB_0Wnd_Mar22Out	300	0.66	1.18	2.47	0.26
Base_400_270PVB_0Wnd_Mar22Out	400	0.04	0.05	0.09	0.01

Figure 66. EUE and additional firm capacity, year 2029. New Firm Generation sensitivity



6.5.3 Firm Capacity Based on Paired Renewable Size

Using the latest outage rates, the TAP was interested to see how much firm generation would be needed to achieve the reliability target based on a certain amount of paired renewables that was added. For example, if 270 MW of paired PV was added, how much firm generation would be needed to make the system reliable. Therefore, the following scenarios were tested.

- Base_150_270PVB_0Wnd_Mar22Out
  - Base case with 3-50MW CT generators added in 2029, 270 MW PV+ BESS, and 0MW onshore wind.
  - 270 MW paired PV is the approximate size of the Stage 3 RFP target. The paired BESS was assumed to have 3-hour duration, which is the same size as the paired BESS chosen by RESOLVE as the optimal amount. Onshore wind was removed due to land use and community acceptance concerns.
- Base_300_270PVB_0Wnd_Mar22Out
  - Base_150_270PVB_0Wnd_Mar22Out with 6-50MW CT generators added in 2029 instead of 3-50MW CT generators.
- Base_400_270PVB_0Wnd_Mar22Out
  - Base_150_270PVB_0Wnd_Mar22Out with 8-50MW CT generators added in 2029 instead of 3-50MW CT generators.
- Base_150_958PVB_Mar22Out
  - Base case with 3-50MW CT generators added in 2029 and 958MW PV+BESS. The 958MW PV+BESS is the NREL resource potential on slopes up to 15%. Includes 163 MW of onshore wind.
- Base_250_958PVB_Mar22Out
  - Base_150_958PVB_Mar22Out with 5-50MW CT generators added in 2029 instead of 3-50MW CT generators.
- Base_300_958PVB_Mar22Out
  - Base_150_958PVB_Mar22Out with 6-50MW CT generators added in 2029 instead of 3-50MW CT generators.
- Base_150_1600PVB_Mar22Out
  - Base case with 3-50MW CT generators added in 2029 and 1600MW PV+BESS. The 1600MW PV+BESS is approximately the amount that was added by RESOLVE in 2030. Includes 163 MW of onshore wind.
- Base_200_1600PVB _Mar22Out
  - Base_150_1600PVB_Mar22Out with 4-50MW CT generators added in 2029 instead of 3-50MW CT generators.
- Base_300_1600PVB _Mar22Out
  - Base_150_1600PVB_Mar22Out with 6-50MW CT generators added in 2029 instead of 3-50MW CT generators.

In all scenarios, the paired PV+BESS system was assumed to have a 3-hour duration. This is the same duration, rounded to the nearest hour, of the paired battery that was chosen by RESOLVE as the optimal amount. Shown below in Figure 67, Figure 68, and Figure 69 is the capacity of resources in 2029 for the case with 270 MW paired PV, 958 MW paired PV, and 1600 MW paired PV, respectively.

Figure 67. Probabilistic analysis - resource capacity summary, year 2029. Firm Capacity cases with 270 MW paired renewables

Year 2029	Existing	Base_150_270PVB_0Wnd_Mar22Out	Base_300_270PVB_0Wnd_Mar22Out	Base_400_270PVB_0Wnd_Mar22Out
Existing Firm	1,729	970	970	970
Existing PV	188	188	188	188
Existing Wind	123	123	123	123
CBRE	0	185	185	185
Stage 1 Hoohana / Mililani / Waiawa / West O'ahu	0	139.5	139.5	139.5
Stage 2 Barbers Point / Kupono / Mountain View / Waiawa2	0	94	94	94
Future PV	0	270	270	270
Future Wind	0	0	0	0
Future Firm Units	0	150 MW (3-50 MW CT)	300 MW (6-50 MW CT)	400 MW (8-50 MW CT)
Total	**2,040**	**2,120**	**2,270**	**2,370**
Stage 1 BESS	0	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh
Stage 2 BESS (incl. Kapolei BESS)	0	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh
Future BESS	0	557 MW / 1,349 MWh	557 MW / 1,349 MWh	557 MW / 1,349 MWh
Total	**0 MW / 0 MWh**	**975 MW / 2,975 MWh**	**975 MW / 2,975 MWh**	**975 MW / 2,975 MWh**

Figure 68. Probabilistic analysis - resource capacity summary, year 2029. Firm Capacity cases with 958 MW paired renewables

Year 2029	Existing	Base_150 958PVB Mar22Out	Base_250 958PVB Mar22Out	Base_300 958PVB Mar22Out
Existing Firm	1,729	970	970	970
Existing PV	188	188	188	188
Existing Wind	123	123	123	123
CBRE	0	185	185	185
Stage 1 Hoohana / Mililani / Waiawa / West O'ahu	0	139.5	139.5	139.5
Stage 2 Barbers Point / Kupono / Mountain View / Waiawa2	0	94	94	94
Future PV	0	958	958	958
Future Wind	0	163	163	163
Future Firm Units	0	150 MW (3-50 MW CT)	250 MW (5-50 MW CT)	300 MW (6-50 MW CT)
Total	**2,040**	**2,971**	**3,121**	**3,121**
Stage 1 BESS	0	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh
Stage 2 BESS (incl. Kapolei BESS)	0	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh
Future BESS	0	1,245 MW / 3,413 MWh	1,245 MW / 3,413 MWh	1,245 MW / 3,413 MWh
Total	**0 MW / 0 MWh**	**1,663 MW / 5,039 MWh**	**1,663 MW / 5,039 MWh**	**1,663 MW / 5,039 MWh**

Figure 69. Probabilistic analysis - resource capacity summary, year 2029. Firm Capacity cases with 1600 MW paired renewables

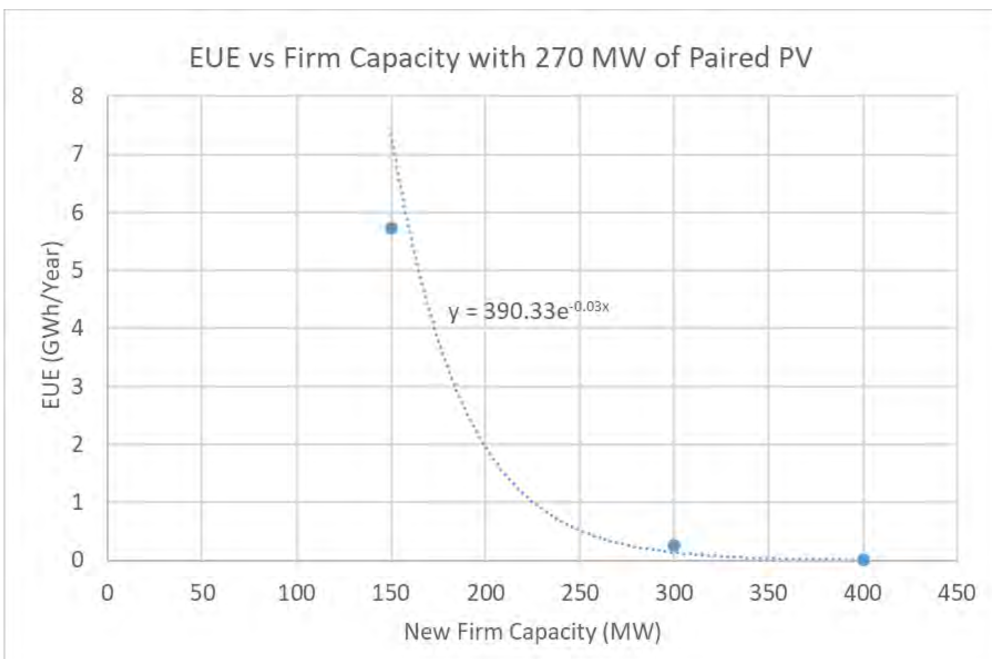
Year 2029	Existing	Base_150_1600PVB_Mar22Out	Base_200_1600PVB_Mar22Out	Base_300_1600PVB_Mar22Out
Existing Firm	1,729	970	970	970
Existing PV	188	188	188	188
Existing Wind	123	123	123	123
CBRE	0	185	185	185
Stage 1 Hoohana / Mililani / Waiawa / West O'ahu	0	139.5	139.5	139.5
Stage 2 Barbers Point / Kupono / Mountain View / Waiawa2	0	94	94	94
Future PV	0	1600	1600	1600
Future Wind	0	163	163	163
Future Firm Units	0	150 MW (3-50 MW CT)	200 MW (4-50 MW CT)	300 MW (6-50 MW CT)
Total	**2,040**	**3,613**	**3,663**	**3,763**
Stage 1 BESS	0	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh
Stage 2 BESS (incl. Kapolei BESS)	0	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh
Future BESS	0	1,887 MW / 5,339 MWh	1,887 MW / 5,339 MWh	1,887 MW / 5,339 MWh
Total	**0 MW / 0 MWh**	**2,305 MW / 6,965 MWh**	**2,305 MW / 6,965 MWh**	**2,305 MW / 6,965 MWh**

Shown below in Figure 70 and Figure 71 is the relationship between the reliability metrics and the new firm capacity in 2029 for the Base case with 270 MW of paired PV and recent outage rates. The trendline produced by the probabilistic results shown in Figure 71 suggest that with 270 MW of paired PV, the EUE reliability target of 0.137 GWh/year can be achieve with approximately 300 MW of new firm generation. Because the curve fit does not directly intersect the cases that were explicitly modeled, it may slightly understate the firm capacity need as shown here when comparing the 300 MW based on curve fit against the 300 MW that was modeled and did not meet the EUE target. However, it is directionally consistent when compared to the curve fits at 958 MW and 1,600 MW of paired PV to show trends in firm capacity need.

Figure 70. Probabilistic analysis - results summary, year 2029. Firm Capacity cases with 270 MW paired PV

Year 2029	New Firm (MW)	New Paired PV (MW)	New Onshore Wind (MW)	LOLE (Days/Year)	LOLEv (Events/Year)	LOLH (Hours/Year)	EUE (GWH/Year)
Existing (2021)	0	0	0	1.18	1.30	2.90	0.13
Base_150_270PVB_0Wnd_Mar22Out	150	270	0	9.25	17.75	42.42	5.74
Base_300_270PVB_0Wnd_Mar22Out	300	270	0	0.66	1.18	2.47	0.26
Base_400_270PVB_0Wnd_Mar22Out	400	270	0	0.04	0.05	0.09	0.01

Figure 71. EUE and new firm capacity in 2029. Firm Capacity cases with 270 MW paired PV

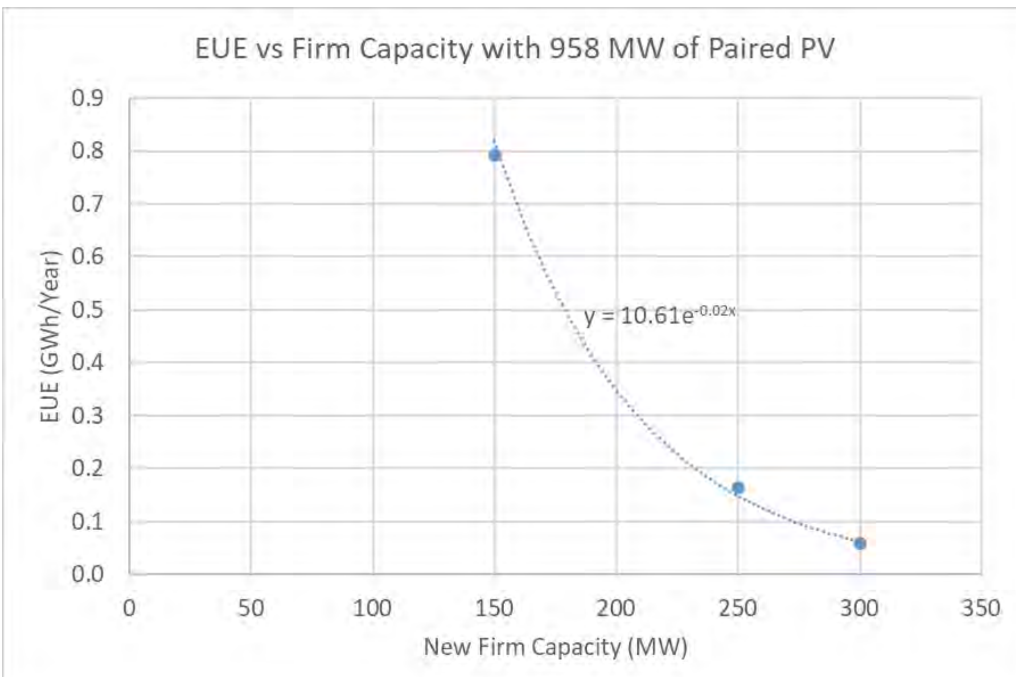


Shown below in Figure 72 and Figure 73 is the relationship between the reliability metrics and the new firm capacity in 2029 for the Base case with 958 MW of paired PV and recent outage rates. The trendline produced by the probabilistic results shown in Figure 73 suggest that with 958 MW of paired PV, the EUE reliability target of 0.137 GWh/year can be achieved with approximately 255 MW of new firm generation.

Figure 72. Probabilistic analysis - results summary, year 2029. Firm Capacity cases with 958 MW Paired PV

Year 2029	New Firm (MW)	New Paired PV (MW)	New Onshore Wind (MW)	LOLE (Days/Year)	LOLEv (Events/Year)	LOLH (Hours/Year)	EUE (GWH/Year)
Existing (2021)	0	0	0	1.18	1.30	2.90	0.13
Base_150_958PVB_Mar22Out	150	958	163	0.98	1.98	4.12	0.79
Base_250_958PVB_Mar22Out	250	958	163	0.18	0.42	0.87	0.16
Base_300_958PVB_Mar22Out	300	958	163	0.08	0.20	0.37	0.06

Figure 73. EUE and new firm capacity in 2029. Firm Capacity cases with 958 MW paired PV

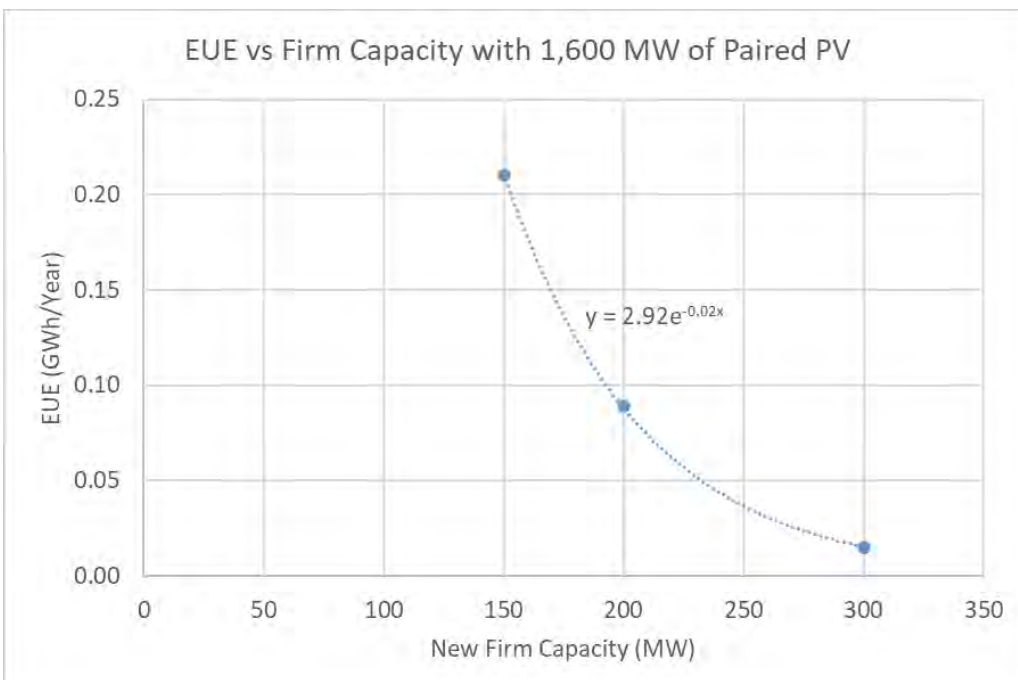


Shown below in Figure 74 and Figure 75 is the relationship between the reliability metrics and the new firm capacity in 2029 for the Base case with 1,600 MW of paired PV and recent outage rates. The trendline produced by the probabilistic results shown in Figure 75 suggest that with 1,600 MW of paired PV, the EUE reliability target of 0.137 GWh/year can be achieve with approximately 175 MW of new firm generation.

Figure 74. Probabilistic analysis - results summary, year 2029. Firm Capacity cases with 1,600 MW paired PV

Year 2029	New Firm (MW)	New Paired PV (MW)	New Onshore Wind (MW)	LOLE (Days/Year)	LOLEv (Events/Year)	LOLH (Hours/Year)	EUE (GWH/Year)
Existing (2021)	0	0	0	1.18	1.30	2.90	0.13
Base_150_ 1600PVB_ Mar22Out	150	1,600	163	0.22	0.49	0.84	0.21
Base_200_ 1600PVB_ Mar22Out	200	1,600	163	0.08	0.18	0.34	0.09
Base_300_ 1600PVB_ Mar22Out	300	1,600	163	0.01	0.04	0.07	0.02

Figure 75. EUE and new firm capacity in 2029. Firm Capacity cases with 1,600 MW paired PV



6.5.4 Long-Duration Energy Storage

Using the latest outage rates, the TAP was also interested to see how the metrics are affected by the size of the standalone BESS system. Therefore, the following scenarios were tested.

- Base_300_Mar22Out
  - 300MW of firm generation is added to the Base case resource plan. This is the same as the Base_508 Staggered scenario and consist of 6-50MW CT generators.
- Base_150_150MW12hrSaB_Mar22Out
  - Base_300_Mar22Out with 150MW of new firm generation replaced with 150MW-12hr Standalone BESS.
- Base_300_270PVB_0Wd_Mar22Out
  - Base_300_Mar22Out with 270MW PV+BESS system added to the Base resource plan, but without the onshore wind. The 270MW PV+BESS is the approximate size of the Stage 3 RFP. Onshore wind was removed due to land use and community acceptance concerns.
- Base_150_150MW12hrSaB_270PVB_0Wd_Mar22Out
  - Base_300_270PVB_0Wd_Mar22Out with 150MW of new firm generation replaced with 150MW-12hr Standalone BESS.
- Base_300_958PVB_Mar22Out
  - Base_300_Mar22Out with 958MW PV+BESS system added to the Base resource plan. The 958MW PV+BESS is the NREL resource potential on slopes up to 15%.
- Base_150_150MW12hrSaB_958PVB_Mar22Out
  - Base_300_958PVB_Mar22Out with 150MW of new firm generation replaced with 150MW-12hr Standalone BESS.

Shown below in Figure 76 is the capacity of resources in 2029 for these cases.

Figure 76. Probabilistic analysis - resource capacity summary, year 2029. Long-Duration Energy Storage sensitivity

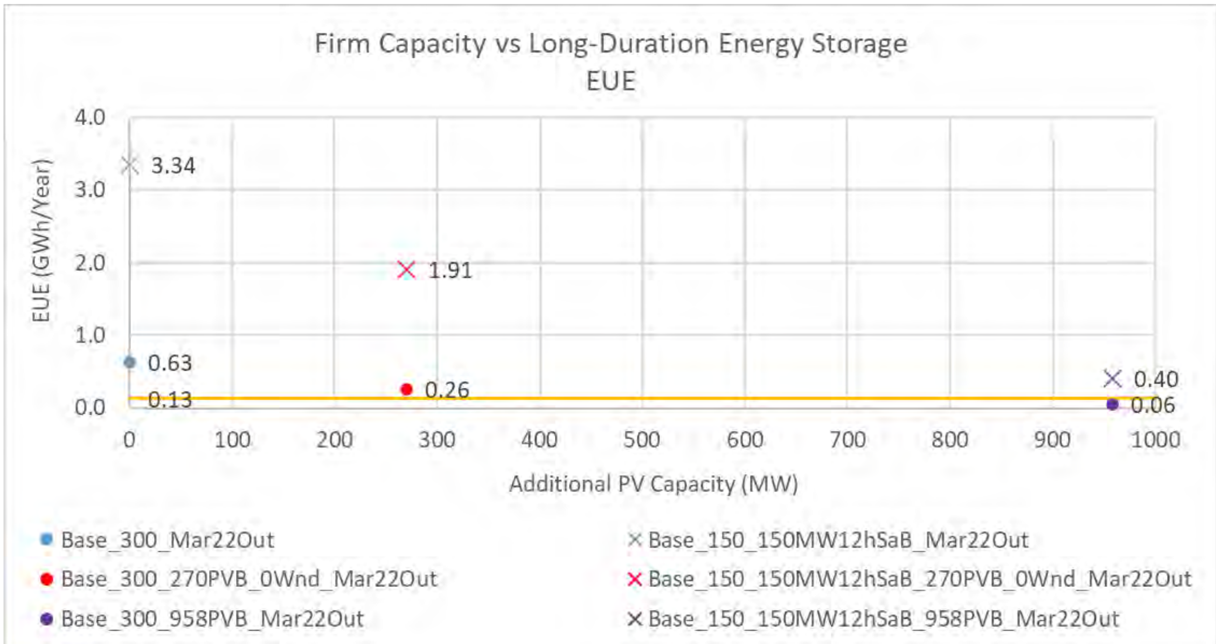
Year 2029	Existing	Base_300 Mar22Out	Base_150 150MW12hrSaB_ Mar22Out	Base_300 270PVB_0Wd Mar22Out	Base_150 150MW12hrSaB_ 270PVB_0Wd Mar22Out	Base_300 958PVB Mar22Out	Base_150 150MW12hrSaB_ 958PVB Mar22Out
Existing Firm	1,729	970	970	970	970	970	970
Existing PV	188	188	188	188	188	188	188
Existing Wind	123	123	123	123	123	123	123
CBRE	0	185	185	185	185	185	185
Stage 1 Hoohana / Mililani / Waiawa / West O'ahu	0	139.5	139.5	139.5	139.5	139.5	139.5
Stage 2 Barbers Point / Kupono / Mountain View / Waiawa2	0	94	94	94	94	94	94
Future PV	0	0	0	270	270	958	958
Future Wind	0	163	163	0	0	163	163
Future Firm Units	0	300 MW (6-50 MW CT)	150 MW (3-50 MW CT)	300 MW (6-50 MW CT)	150 MW (3-50 MW CT)	300 MW (6-50 MW CT)	150 MW (3-50 MW CT)
Total	**2,040**	**2,163**	**2,013**	**2,270**	**2,120**	**3,121**	**2,971**
Stage 1 BESS	0	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh
Stage 2 BESS (incl. Kapolei BESS)	0	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh
Future BESS	0	287 MW / 539 MWh	437 MW / 2,339 MWh	557 MW / 1,349 MWh	707 MW / 3,149 MWh	1,245 MW / 3,413 MWh	1,395 MW / 5,213 MWh
Total	**0 MW / 0 MWh**	**705 MW / 2,165 MWh**	**855 MW / 3,965 MWh**	**975 MW / 2,975 MWh**	**1,125 MW / 4,775 MWh**	**1,663 MW / 5,039 MWh**	**1,813 MW / 6,839 MWh**

Shown below in Figure 77 is the impact that a 150MW/12-hour energy storage system has on the various reliability metrics discussed earlier and how it compares to 150MW of firm generation instead. This information is also shown in Figure 78. As shown, in all scenarios, the 150MW new firm generation results in better reliability than a 150 MW/12-hour standalone energy storage system, even with large amounts of renewables on the system.

Figure 77. Probabilistic analysis - results summary, year 2029. Long-Duration Energy Storage sensitivity

Year 2029	New Firm Generation (MW)	New Paired PV (MW)	New Standalone Storage MW/MWh)	LOLE (Days/Year)	LOLEv (Events/Year)	LOLH (Hours/Year)	EUE (GWH/Year)
Existing (2021)	0	0	0MW / 0MWh	1.18	1.30	2.90	0.13
Base_300_Mar22Out	300	0	287 MW / 539 MWh	1.30	2.19	5.98	0.63
Base_150_150MW12hrSaB_Mar22Out	150	0	437 MW / 2,339 MWh	4.15	8.91	23.19	3.34
Base_300_270PVB_0Wd_Mar22Out	300	270	287 MW / 539 MWh	0.66	1.18	2.47	0.26
Base_150_150MW12hrSaB_270PVB_0Wd_Mar22Out	150	270	437 MW / 2,339 MWh	2.48	5.16	12.17	1.91
Base_300_958PVB_Mar22Out	300	958	287 MW / 539 MWh	0.08	0.20	0.37	0.06
Base_150_150MW12hrSaB_958PVB_Mar22Out	150	958	437 MW / 2,339 MWh	0.36	0.84	1.89	0.40

Figure 78. EUE, firm capacity and long-duration storage in 2029. Long-Duration Energy Storage sensitivity



6.5.5 Removal from Service Schedule Sensitivity

Sensitivities on the removal from service schedule were also analyzed to study how the schedule may be adjusted to improve reliability based on the amount of new firm generation.

- Base_150_270PVB_0Wd_Mar22Out
  - 150MW of new firm generation and 270MW PV+BESS system is added to the Base resource plan. The 270MW PV+BESS is the approximate size of the Stage 3 procurement. Onshore or land-based wind was removed due to land use and community acceptance concerns.
- Base_150_270PVB_0Wd_170HE_Mar22Out
  - Base_150_270PVB_0Wd_Mar22Out with the removal of 170MW of utility thermal generation delayed.
- Base_150_270PVB_0Wd_280HE_Mar22Out
  - Base_150_270PVB_0Wd_Mar22Out with the removal of 280MW of utility thermal generation delayed.
- Base_300_270PVB_0Wd_Mar22Out
  - Base_150_270PVB_0Wd_Mar22Out with 300MW of new firm generation instead of 150MW of new firm generation
- Base_300_270PVB_0Wd_170HE_Mar22Out
  - Base_300_270PVB_0Wd_Mar22Out with the removal of 170MW of utility thermal generation delayed.
- Base_400_270PVB_0Wd_Mar22Out
  - Base_150_270PVB_0Wd_Mar22Out with 400MW of new firm generation instead of 150MW of new firm generation.

- Base_400_270PVB_0Wd_wo170HE_Mar22Out
    - Base_400_270PVB_0Wd_Mar22Out with the removal of an additional 170MW of utility firm generation accelerated.

Shown below in Figure 79 is the capacity of resources in 2029 for these cases. Due to rounding, the existing firm capacity may be slightly different from the amount of removed capacity that is accelerated/delayed in the case descriptions above.

Figure 79. Probabilistic analysis – resource capacity summary, year 2029. Removal from Service sensitivity

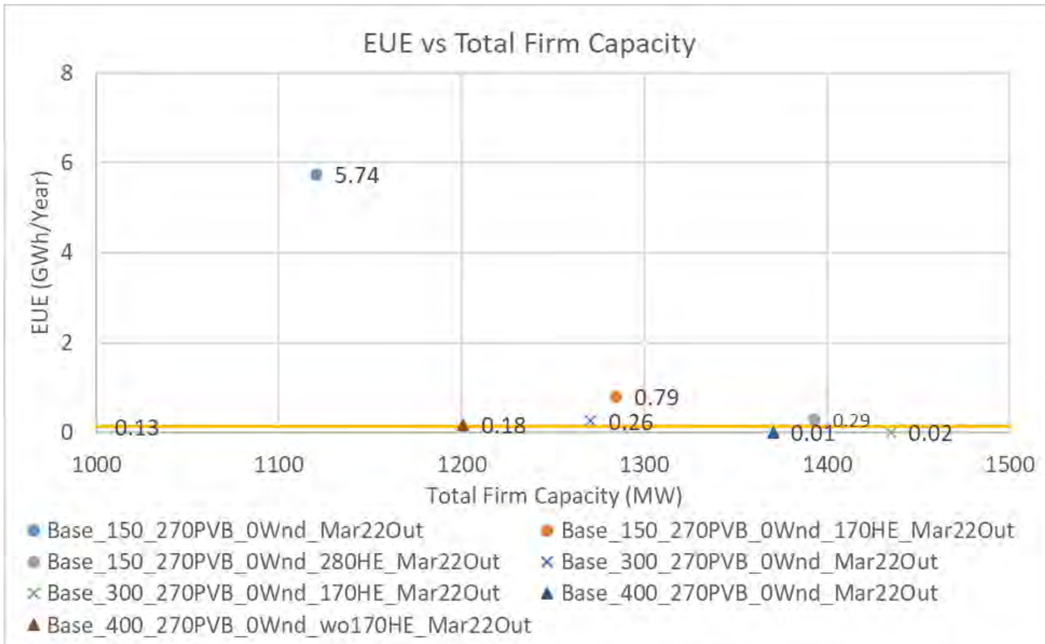
Year 2029	Existing	Base_150 270PVB_0Wd Mar22Out	Base_150 270PVB_0Wd 170HE_ Mar22Out	Base_150 270PVB_0Wd 280HE_ Mar22Out	Base_300 270PVB_0Wd Mar22Out	Base_300 270PVB_0Wd 170HE_ Mar22Out	Base_400 270PVB_0Wd Mar22Out	Base_400 270PVB_0Wd Mar22Out
Existing Firm	1,729	970	1,135	1,243	970	1,135	970	801
Existing PV	188	188	188	188	188	188	188	188
Existing Wind	123	123	123	123	123	123	123	123
CBRE	0	185	185	185	185	185	185	185
Stage 1 Hoohana / Mililani / Waiawa / West O'ahu	0	139.5	139.5	139.5	139.5	139.5	139.5	139.5
Stage 2 Barbers Point / Kupono / Mountain View / Waiawa2	0	94	94	94	94	94	94	94
Future PV	0	270	270	270	270	270	270	270
Future Wind	0	0	0	0	0	0	0	0
Future Firm Units	0	150 MW (3-50 MW CT)	150 MW (3-50 MW CT)	150 MW (3-50 MW CT)	300 MW (6-50 MW CT)	300 MW (6-50 MW CT)	400 MW (8-50 MW CT)	400 MW (8-50 MW CT)
Total	**2,040**	**2,120**	**2,284**	**2,393**	**2,270**	**2,434**	**2,370**	**2,201**
Stage 1 BESS	0	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh
Stage 2 BESS (incl. Kapolei BESS)	0	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh
Future BESS	0	557 MW / 1,349 MWh	557 MW / 1,349 MWh	557 MW / 1,349 MWh	557 MW / 1,349 MWh	557 MW / 1,349 MWh	557 MW / 1,349 MWh	557 MW / 1,349 MWh
Total	**0 MW / 0 MWh**	**975 MW / 2,975 MWh**	**975 MW / 2,975 MWh**	**975 MW / 2,975 MWh**	**975 MW / 2,975 MWh**	**975 MW / 2,975 MWh**	**975 MW / 2,975 MWh**	**975 MW / 2,975 MWh**

Shown below in Figure 80 is the impact that the existing and new firm generation capacity has on the various reliability metrics discussed earlier. This information is also shown in Figure 81. As shown below, with 270MW of paired PV+BESS and only 150MW of new firm generation, most of the reliability targets will not be met, even with delaying the removal of 280MW of utility firm generation. This demonstrates the urgency in which the services provided by existing fossil-fuel generation must be replaced to reduce the risk of an aging and less reliable generation fleet. With 270MW of paired PV+BESS and the Base plan removal from service schedule, at least 300MW of new firm generation will be needed to meet the reliability targets.

Figure 80. Probabilistic analysis - results summary, year 2029. Removal from Service sensitivity

Year 2029	Existing Firm Generation (MW)	New Firm Generation (MW)	LOLE (Days/Year)	LOLEv (Events/Year)	LOLH (Hours/Year)	EUE (GWH/Year)
Existing (2021)	1,729	0	1.18	1.30	2.90	0.13
Base_150_270PVB_0Wd_Mar22Out	970	150	9.25	17.75	42.42	5.74
Base_150_270PVB_0Wd_170HE_Mar22Out	1,135	150	1.70	3.20	6.52	0.79
Base_150_270PVB_0Wd_280HE_Mar22Out	1,243	150	0.54	1.02	2.25	0.29
Base_300_270PVB_0Wd_Mar22Out	970	300	0.66	1.18	2.47	0.26
Base_300_270PVB_0Wd_170HE_Mar22Out	1,135	300	0.09	0.16	0.22	0.02
Base_400_270PVB_0Wd_Mar22Out	970	400	0.04	0.05	0.09	0.01
Base_400_270PVB_0Wd_wo170HE_Mar22Out	801	400	0.47	0.92	1.82	0.18

Figure 81. EUE and total firm capacity in 2029. Removal from Service sensitivity



6.5.6 Load Sensitivity

Additional load sensitivities were done to evaluate the low load and high load bookends using the updated forced outage rates.

- Base_300_270PVB_0Wd_Mar22Out_HiLd
  - 300MW of new firm generation and 270MW PV+BESS system is added to the Base resource plan. The 270MW PV+BESS is the approximate size of the next O'ahu variable RFP. Onshore wind was removed due to land use and community acceptance concerns.
  - With the high load forecast
- Base_300_270PVB_0Wd_170HE_Mar22Out_HiLd
  - Base_300_270PVB_0Wd_Mar22Out_HiLd with the removal of 170MW of utility thermal generation delayed.
- Base_300_270PVB_0Wd_280HE_Mar22Out_HiLd
  - Base_300_270PVB_0Wd_Mar22Out_HiLd with the removal of 280MW of utility thermal generation delayed.
- Base_300_270PVB_0Wd_Mar22Out_LwLd
  - Base_300_270PVB_0Wd_Mar22Out_HiLd with the low load forecast
- Base_300_270PVB_0Wd_wo170HE_Mar22Out_LwLd
  - Base_300_270PVB_0Wd_Mar22Out_LwLd with an additional 170MW of utility thermal generation deactivated.

- Base_400_270PVB_0Wd_Mar22Out_HiLd
    - 400MW of new firm generation and 270MW PV+BESS system is added to the Base resource plan. The 270MW PV+BESS is the approximate size of the next O'ahu variable RFP. Onshore wind was removed due to land use and community acceptance concerns.
    - With the high load forecast
- Base_400_270PVB_0Wd_170HE_Mar22Out_HiLd
    - Base_400_270PVB_0Wd_Mar22Out_HiLd with the removal of 170MW of utility thermal generation delayed.
- Base_400_270PVB_0Wd_280HE_Mar22Out_HiLd
    - Base_400_270PVB_0Wd_Mar22Out_HiLd with the removal of 280MW of utility thermal generation delayed.
- Base_400_270PVB_0Wd_Mar22Out_LwLd
    - Base_400_270PVB_0Wd_Mar22Out_HiLd with the low load forecast
- Base_400_270PVB_0Wd_wo170HE_Mar22Out_LwLd
    - Base_400_270PVB_0Wd_Mar22Out_LwLd with an additional 170MW of utility thermal generation removed.

Shown below in Figure 82 is the capacity of resources in 2029 for each case where 300MW of new firm generation was added.

Figure 83 shows the capacity of resources in 2029 for each case where 400MW of new firm generation was added. Due to rounding, the existing firm capacity may be slightly different from the amount of removed capacity that is accelerated/delayed in the case descriptions at the beginning of this section.

Figure 82. Probabilistic analysis – resource capacity summary, year2029. Load sensitivity with 300MW of new firm generation

Year 2029	Existing	Base_300_270PVB_0Wd Mar22Out	Base_300_270PVB_0Wd 170HE_Mar22Out	Base_300_270PVB_0Wd 280HE_Mar22Out	Base_300_270PVB_0Wd wo170HE_Mar22Out
Existing Firm	1,729	970	1,135	1,243	801
Existing PV	188	188	188	188	188
Existing Wind	123	123	123	123	123
CBRE	0	185	185	185	185
Stage Mililani / Mililani / Waiawa / West O‘ahu	0	139.5	139.5	139.5	139.5
Stage 2 Barbers Point / Kupono / Mountain View / Waiawa2	0	94	94	94	94
Future PV	0	270	270	270	270
Future Wind	0	0	0	0	0
Future Firm Units	0	300 MW (6-50 MW CT)	300 MW (6-50 MW CT)	300 MW (6-50 MW CT)	300 MW (6-50 MW CT)
Total	**2,040**	**2,270**	**2,434**	**2,543**	**2,101**
Stage 1 BESS	0	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh
Stage 2 BESS (incl. Kapolei BESS)	0	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh
Future BESS	0	557 MW / 1,349 MWh	557 MW / 1,349 MWh	557 MW / 1,349 MWh	557 MW / 1,349 MWh
Total	**0 MW / 0 MWh**	**975 MW / 2,975 MWh**	**975 MW / 2,975 MWh**	**975 MW / 2,975 MWh**	**975 MW / 2,975 MWh**

Figure 83. Probabilistic analysis – resource capacity summary, year 2029. Load sensitivity with 400MW of new firm generation

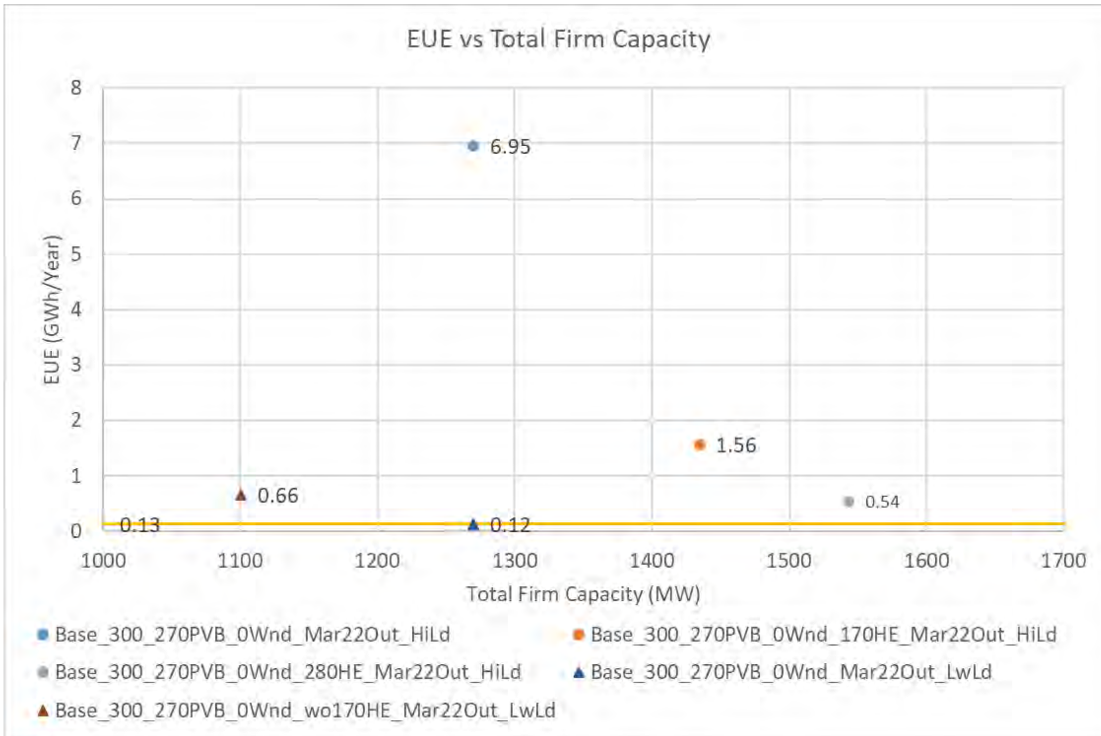
Year 2029	Existing	Base 400_270PVB_0Wd Mar22Out	Base 400_270PVB_0Wd 170HE_Mar22Out	Base 400_270PVB_0Wd 280HE_Mar22Out	Base 400_270PVB_0Wd wo170HE_Mar22Out
Existing Firm	1,729	970	1,135	1,243	801
Existing PV	188	188	188	188	188
Existing Wind	123	123	123	123	123
CBRE	0	185	185	185	185
Stage 1 Hoohana / Mililani / Waiawa / West O'ahu	0	139.5	139.5	139.5	139.5
Stage 2 Barbers Point / Kupono / Mountain View / Waiawa2	0	94	94	94	94
Future PV	0	270	270	270	270
Future Wind	0	0	0	0	0
Future Firm Units	0	400 MW (8-50 MW CT)	400 MW (8-50 MW CT)	400 MW (8-50 MW CT)	400 MW (8-50 MW CT)
Total	**2,040**	**2,370**	**2,534**	**2,643**	**2,201**
Stage 1 BESS	0	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh
Stage 2 BESS (incl. Kapolei BESS)	0	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh
Future BESS	0	557 MW / 1,349 MWh	557 MW / 1,349 MWh	557 MW / 1,349 MWh	557 MW / 1,349 MWh
Total	**0 MW / 0 MWh**	**975 MW / 2,975 MWh**	**975 MW / 2,975 MWh**	**975 MW / 2,975 MWh**	**975 MW / 2,975 MWh**

Shown below in Figure 84 is the impact that the firm generation capacity and load forecast has on the various reliability metrics discussed earlier. This is for the case where 300MW of new firm generation is added. This information is also shown in Figure 85. As shown below, with 300MW of new firm generation, none of the reliability targets will be met under the high load forecast even with the delayed deactivation of 280MW of firm generation. With the low load forecast, the Stage 3 procurement target of 270MW paired PV and 300MW of firm generation, will still be short of the LOLE target.

Figure 84. Probabilistic analysis - results summary, year 2029. Load sensitivity with 300MW of new firm generation

Year 2029	Existing Firm Generation (MW)	New Firm Generation (MW)	LOLE (Days/Year)	LOLEv (Events/Year)	LOLH (Hours/Year)	EUE (GWH/Year)
Existing (2021)	1,729	0	1.18	1.30	2.90	0.13
High Load Forecast						
Base_300_270PVB_0Wd_Mar22Out_HiLd	970	300	10.10	19.42	48.01	6.95
Base_300_270PVB_0Wd_170HE_Mar22Out_HiLd	1,135	300	2.63	4.61	11.04	1.56
Base_300_270PVB_0Wd_280HE_Mar22Out_HiLd	1,243	300	1.00	1.82	4.02	0.54
Low Load Forecast						
Base_300_270PVB_0Wd_Mar22Out_LwLd	970	300	0.26	0.48	0.99	0.12
Base_300_270PVB_0Wd_wo170HE_Mar22Out_LwLd	801	300	1.51	3.012	5.91	0.66

Figure 85. EUE and total firm capacity in 2029. Load sensitivity with 300MW of new firm generation

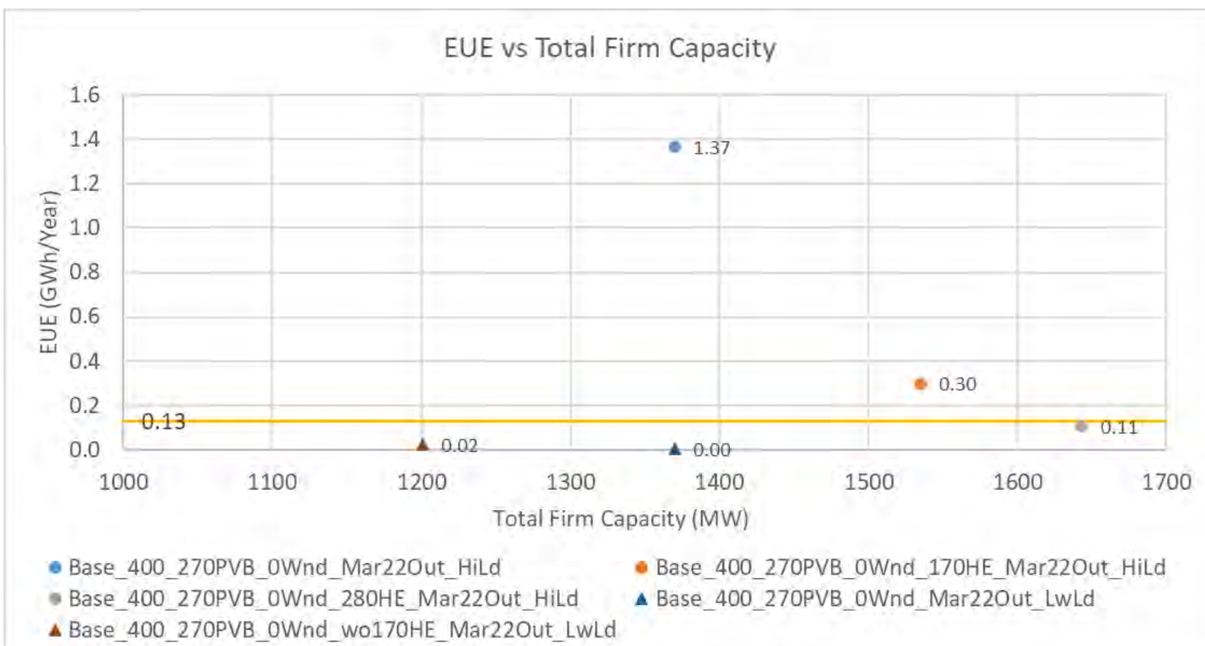


Shown below in Figure 86 is the impact that the firm generation capacity and load forecast has on the various reliability metrics discussed earlier. This is for the case where 400 MW of new firm generation is added. This information is also shown in Figure 87. As shown below, with 400 MW of new firm generation, under the high load forecast even with the delayed deactivation of 280 MW of firm generation LOLE will not meet the 0.1 metric. With the low load forecast, the Stage 3 procurement target of 270 MW paired PV and 400 MW of firm generation, the reliability targets are satsified. Also, with the low load forecast, and 400MW of firm generation, additional fossil-fuel generation capacity could be deactivated and acheive close to the reliability targets.

Figure 86. Probabilistic analysis - results summary, year 2029. Load sensitivity with 400MW of new firm generation

Year 2029	Existing Firm Generation (MW)	New Firm Generation (MW)	LOLE (Days/Year)	LOLEv (Events/Year)	LOLH (Hours/Year)	EUE (GWH/Year)
Existing (2021)	1,729	0	1.18	1.30	2.90	0.13
High Load Forecast						
Base_400_270PVB_0Wd_Mar22Out_HiLd	970	400	2.52	4.63	10.49	1.37
Base_400_270PVB_0Wd_170HE_Mar22Out_HiLd	1,135	400	0.65	1.12	2.59	0.30
Base_400_270PVB_0Wd_280HE_Mar22Out_HiLd	1,243	400	0.19	0.30	0.78	0.11
Low Load Forecast						
Base_400_270PVB_0Wd_Mar22Out_LwLd	970	400	0.03	0.04	0.09	0.00
Base_400_270PVB_0Wd_wo170HE_Mar22Out_LwLd	801	400	0.12	0.19	0.30	0.02

Figure 87. EUE and total firm capacity in 2029. Load sensitivity with 400MW of new firm generation



6.5.7 DER and EE Freeze Sensitivity

Shown below in Figure 88 is the amount of DER including distributed PV and BESS and EE assumed in the Freeze case versus the Base case. The EE in the freeze case includes the forecasted Codes and Standards. The DER in both the Base case and Freeze case includes degradation.

Figure 88. Forecasted 2029 DER and EE sales (GWh). Base and Freeze scenarios

2029 (Sales GWH)	Acquired and Future DER	Future EE
Base	1,384	992
Freeze	919	530

Using the latest outage rates, a few scenarios were tested to determine what firm capacity would be needed if the DER and EE freeze forecast were used.

- Base_300_270PVB_0Wnd_Fze_Mar22Out
    - Base case with 6-50MW CT generators added in 2029, 270 MW PV+ BESS, and 0MW onshore wind.
    - 270 MW paired PV is the approximate size of the Stage 3 procurement target. The paired BESS was assumed to have 3-hour duration, which is the same size as the paired BESS chosen by RESOLVE as the optimal amount. Onshore wind was removed due to land use and community acceptance concerns.
    - DGPV/DBESS amounts frozen at the end of 2020. EE amount was frozen at the end of 2021.
    - EV load was assumed to be unmanaged.
- Base_400_270PVB_0Wnd_Fze_Mar22Out
    - Base_300_270PVB_0Wnd_Mar22Out with 8-50MW CT generators added in 2029 instead of 6-50MW CT generators.
- Base_500_270PVB_0Wnd_Fze_Mar22Out
    - Base_300_270PVB_0Wnd_Mar22Out with 10-50MW CT generators added in 2029 instead of 6-50MW CT generators.

Shown below in Figure 89 is the capacity of resources in 2029 for these cases.

Figure 89. Probabilistic analysis – resource capacity summary, year 2029. DER Freeze sensitivity

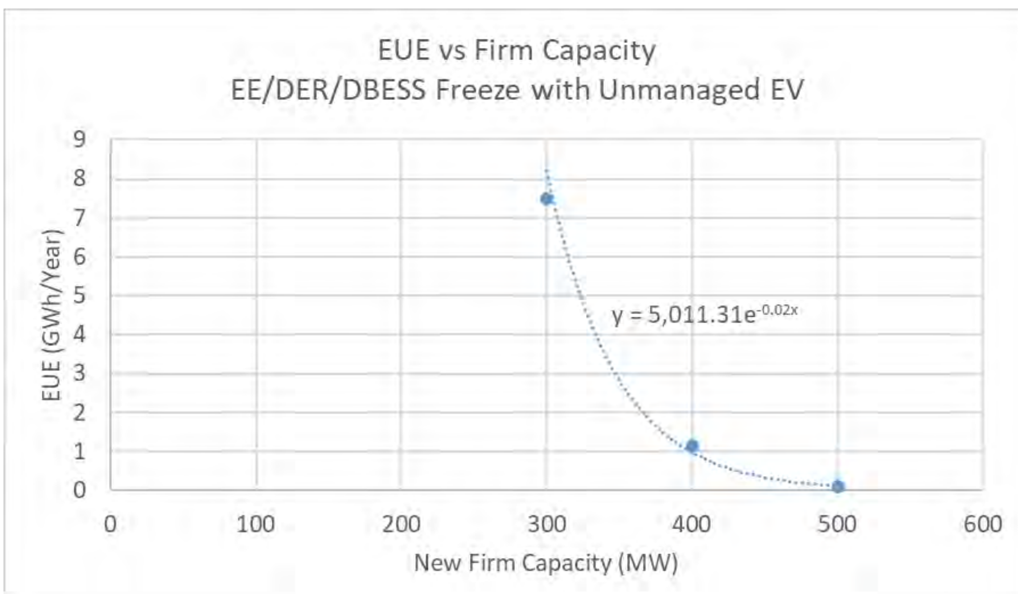
Year 2029	Existing	Base_300_270PVB_0Wnd Fze_Mar22Out	Base_400_270PVB_0Wnd Fze_Mar22Out	Base_500_270PVB_0Wnd Fze_Mar22Out
Existing Firm	1,729	970	970	970
Existing PV	188	188	188	188
Existing Wind	123	123	123	123
CBRE	0	185	185	185
Stage 1 Hoohana / Mililani / Waiawa / West O'ahu	0	139.5	139.5	139.5
Stage 2 Barbers Point / Kupono / Mountain View / Waiawa2	0	94	94	94
Future PV	0	270	270	270
Future Wind	0	0	0	0
Future Firm Units	0	300 MW (6-50 MW CT)	400 MW (8-50 MW CT)	500 MW (10-50 MW CT)
Total	**2,040**	**2,270**	**2,370**	**2,470**
Stage 1 BESS	0	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh
Stage 2 BESS (incl. Kapolei BESS)	0	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh
Future BESS	0	557 MW / 1,349 MWh	557 MW / 1,349 MWh	557 MW / 1,349 MWh
Total	**0 MW / 0 MWh**	**975 MW / 2,975 MWh**	**975 MW / 2,975 MWh**	**975 MW / 2,975 MWh**

Shown below in Figure 90 is the impact that the new firm generation has on the various reliability metrics if the DER/EE were frozen and the EV charging was unmanaged. In this situation, with the DER frozen at 2021 levels and EE frozen at 2022 levels, the system load is approximately 7,500 GWh, resulting in an EUE target of approximately 0.15 GWh, or 0.002% of system load. A trendline can be used to estimate the amount of firm generation needed. Using the trendline provided in Figure 91, the new firm capacity needed is approximately 485 MW, or approximately 185 MW more. This empahsizes the importance role of customer resources providing grid flexibility and their contributions to resource adequacy.

Figure 90. Probabilistic analysis - results summary, year 2029. DER Freeze sensitivity

Year 2029	New Firm Generation (MW)	LOLE (Days/Year)	LOLEv (Events/Year)	LOLH (Hours/Year)	EUE (GWH/Year)
Existing (2021)	0	1.18	1.30	2.90	0.13
Base_300_270PVB_0Wd_Fze_Mar22Out	300	10.08	19.78	54.84	7.51
Base_400_270PVB_0Wd_Fze_Mar22Out	400	2.31	4.30	10.28	1.16
Base_500_270PVB_0Wd_Fze_Mar22Out	500	0.31	0.58	1.12	0.10

Figure 91. EUE and new firm capacity in 2029. DER Freeze sensitivity



6.5.8 Additional DER/DR Resources

There was some stakeholder inquiry into whether a Demand Response program using batteries could help reduce the new firm generation target in addition to the distributed resources already consdiered as shown in the previous section. A few scenarios were tested assuming additional short-duration energy storage was installed in 2029.

- Base_300_270PVB_0Wd_Mar22Out
  - Base case with 300 MW of new firm generation, 270 MW PV+ BESS, and 0MW onshore wind.
  - The 270MW PV+BESS is the approximate size of the next Oʻahu variable RFP. Onshore wind was removed due to land use and community acceptance concerns.
- Base_150_150MW2hrSaB_270PVB_0Wd_Mar22Out
  - Base_300_270PVB_0Wd_Mar22Out with 150MW of new firm generation replaced with 150MW-2hr Standalone BESS.
- Base_150_150MW12hrSaB_270PVB_0Wd_Mar22Out
  - Base_300_270PVB_0Wd_Mar22Out with 150MW of new firm generation replaced with 150MW-12hr Standalone BESS.
- Base_300_105MW2hrSaB_270PVB_0Wd_Mar22Out
  - Base_300_270PVB_0Wd_Mar22Out with an additional 105MW-2hr Standalone BESS.
- Base_400_270PVB_0Wd_Mar22Out
  - Base_300_270PVB_0Wd_Mar22Out with 8-50MW CT generators added in 2029 instead of 3-50MW CT generators.

Shown below in Figure 92 is the capacity of resources in 2029 for these cases.

Figure 92. Probabilistic analysis – resource capacity summary, year 2029. Additional DER/DR sensitivity

Year 2029	Existing	Base_300 _270PVB_0Wnd Mar22Out	Base_150 150MW2hrSaB_ 270PVB_0Wd Mar22Out	Base_150 150MW12hrSaB_ 270PVB_0Wd Mar22Out	Base_300 105MW2hrSaB_ 270PVB_0Wd Mar22Out	Base_400 270PVB_0Wnd Mar22Out
Existing Firm	1,729	970	970	970	970	970
Existing PV	188	188	188	188	188	188
Existing Wind	123	123	123	123	123	123
CBRE	0	185	185	185	185	185
Stage 1 Hoohana / Mililani / Waiawa / West O'ahu	0	139.5	139.5	139.5	139.5	139.5
Stage 2 Barbers Point / Kupono / Mountain View / Waiawa2	0	94	94	94	94	94
Future PV	0	270	270	270	270	270
Future Wind	0	0	0	0	0	0
Future Firm Units	0	300 MW (6-50 MW CT)	150 MW (3-50 MW CT)	150 MW (3-50 MW CT)	300 MW (6-50 MW CT)	400 MW (8-50 MW CT)
Total	**2,040**	**2,270**	**2,120**	**2,120**	**2,270**	**2,370**
Stage 1 BESS	0	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh
Stage 2 BESS (incl. Kapolei BESS)	0	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh
Future BESS	0	557 MW / 1,349 MWh	707 MW / 1,649 MWh	707 MW / 3,149 MWh	662 MW / 1,559 MWh	557 MW / 1,349 MWh
Total	**0 MW / 0 MWh**	**975 MW / 2,975 MWh**	**1,125 MW / 3,275 MWh**	**1,125 MW / 4,775 MWh**	**1,125 MW / 3,185 MWh**	**975 MW / 2,975 MWh**

Shown below in Figure 93 is the impact that the additional short-duration energy storage has on the various reliability metrics.

Figure 93. Probabilistic analysis - results summary, year 2029. Additional DER/DR sensitivity

Year 2029	New Firm Generation (MW)	New Paired PV (MW)	New Standalone Storage (MW/MWh)	LOLE (Days/Year)	LOLEv (Events/Year)	LOLH (Hours/Year)	EUE (GWH/Year)
Existing (2021)	0	0	0MW / 0MWh	1.18	1.30	2.90	0.13
Base_300_270PVB_0Wd_Mar22Out	300	270	287 MW / 539 MWh	0.66	1.18	2.47	0.26
Base_150_150MW2hrSaB_270PVB_0Wd_Mar22Out	150	270	437 MW / 839 MWh	6.96	13.37	31.32	4.49
Base_150_150MW12hrSaB_270PVB_0Wd_Mar22Out	150	270	437 MW / 2,339 MWh	2.48	5.16	12.17	1.91
Base_300_270PVB_0Wnd_Mar22Out	300	270	287 MW / 539 MWh	0.66	1.18	2.47	0.26
Base_300_105MW2hrSaB_270PVB_0Wd_Mar22Out	300	270	392 MW / 749 MWh	0.48	0.92	1.78	0.19
Base_400_270PVB_0Wnd_Mar22Out	400	270	287 MW / 539 MWh	0.04	0.05	0.09	0.01

Shown in Figure 94 is the impact that accelerating the additional short-duration energy storage has on the EUE and compares it to a long-duration storage and new firm generation with the same power output. As expected, while a longer-duration storage improves reliability more than the short-duration energy storage system, neither improves reliability as much as new firm generation with the same power output.

Shown in Figure 95 is the impact that adding short-duration energy storage to 300MW of new firm generation has on the reliability targets. While the addition of short-duration energy storage improves reliability, it does not improve reliability as much as a firm generator with similar power output.

Figure 94. EUE and total firm capacity in 2029. Additional DER/DR sensitivity

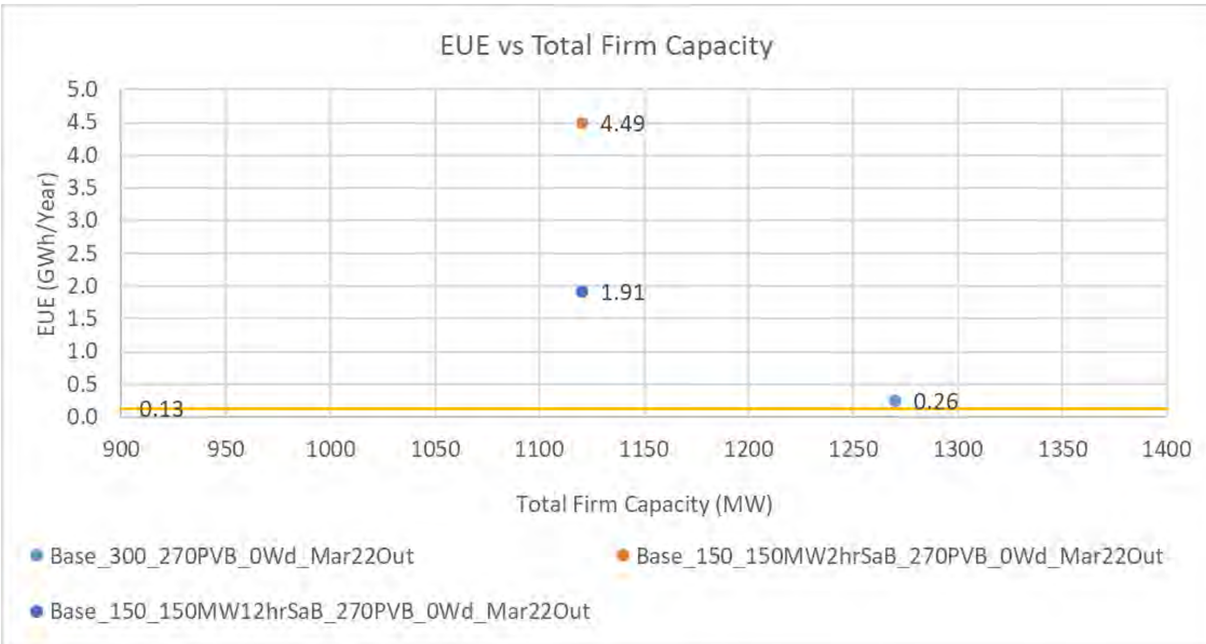
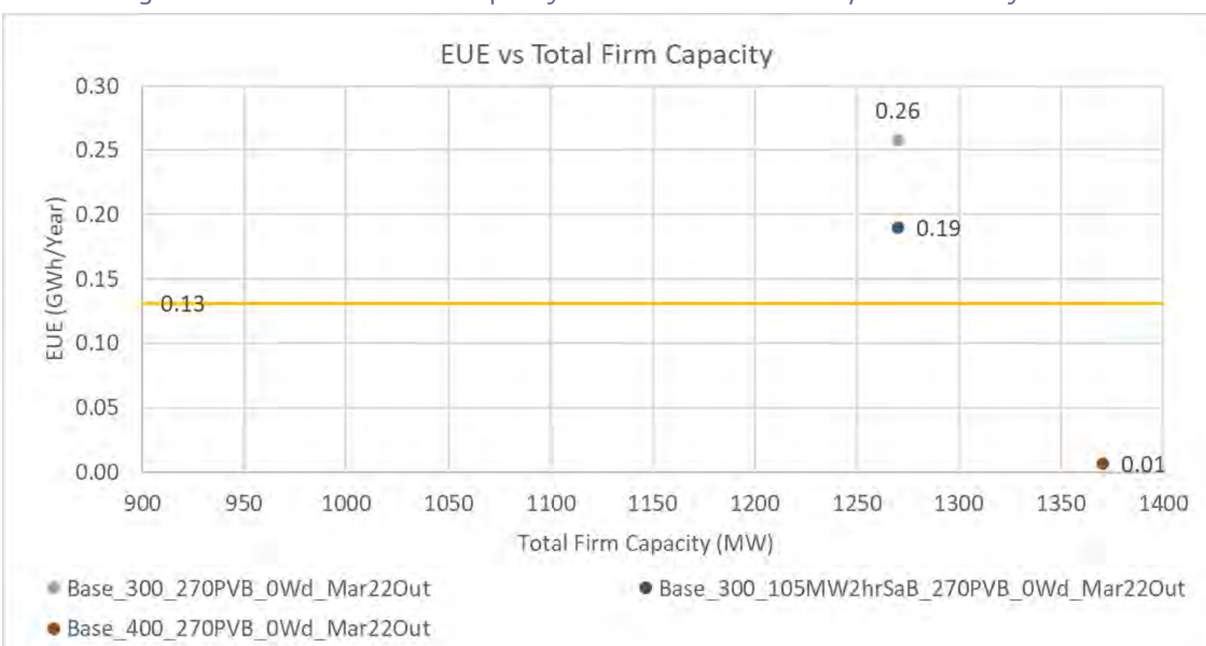


Figure 95. EUE and total firm capacity in 2029. Additional DER/DR sensitivity cont'd



6.5.9 Accelerated Offshore Wind

There was some stakeholder inquiry into how the firm generation target may be affected if offshore wind was capable of being developed earlier than 2035. Using the latest outage rates, a few scenarios were tested assuming offshore wind was installed in 2029.

- Base_270PVB_0Wnd_Mar22Out
  - Base case with 270 MW PV+ BESS and 0MW onshore wind.
  - 270 MW paired PV is the approximate size of the Stage 3 RFP target. The paired BESS was assumed to have 3-hour duration, which is the same size as the paired BESS chosen by RESOLVE as the optimal amount. Onshore wind was removed due to land use and community acceptance concerns.
- Base_270PVB_400OSW_Mar22Out
  - Base_270PVB_0Wnd_Mar22Out with 400 MW of offshore wind.
  - The size of the offshore wind was set at 400 MW because of stakeholder comments that this is the approximate size that would achieve the lowest Levelized Cost of Energy.
- Base_300_270PVB_0Wnd_Mar22Out
  - Base_270PVB_0Wnd_Mar22Out with 300 MW of new firm generation.
- Base_400_270PVB_0Wnd_Mar22Out
  - Base_270PVB_0Wnd_Mar22Out with 400 MW of new firm generation.
- Base_150_270PVB_400OSW_Mar22Out
  - Base_270PVB_400OSW_Mar22Out with 150 MW of firm generation.
- Base_300_270PVB_400OSW_Mar22Out
  - Base_270PVB_400OSW_Mar22Out with 300 MW of firm generation.

Shown below in Figure 96 is the capacity of resources in 2029 for these cases.

Figure 96. Probabilistic analysis - resource capacity summary, year 2029. Accelerated Offshore Wind sensitivity

Year 2029	Existing	Base_270PVB_ 0Wnd Mar22Out	Base_270PVB_ 400OSW Mar22Out	Base_300_270PVB_ 0Wnd Mar22Out	Base_400_270PVB_ 0Wnd Mar22Out	Base_150_270PVB_ 400OSW Mar22Out	Base_300_270PVB_ 400OSW Mar22Out
Existing Firm	1,729	970	970	970	970	970	970
Existing PV	188	188	188	188	188	188	188
Existing Wind	123	123	123	123	123	123	123
CBRE	0	185	185	185	185	185	185
Stage 1 Hoohana / Mililani / Waiawa / West O'ahu	0	139.5	139.5	139.5	139.5	139.5	139.5
Stage 2 Barbers Point / Kupono / Mountain View / Waiawa2	0	94	94	94	94	94	94
Future PV	0	270	270	270	270	270	270
Future Wind	0	0	400	0	0	400	400
Future Firm Units	0	0	0	300 MW (6-50 MW CT)	400 MW (8-50 MW CT)	150 MW (3-50 MW CT)	300 MW (6-50 MW CT)
Total	**2,040**	**1,970**	**2,370**	**2,270**	**2,370**	**2,520**	**2,670**
Stage 1 BESS	0	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh	139.5 MW / 558 MWh
Stage 2 BESS (incl. Kapolei BESS)	0	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh	279 MW / 1,068 MWh
Future BESS	0	557 MW / 1,349 MWh	557 MW / 1,349 MWh	557 MW / 1,349 MWh	557 MW / 1,349 MWh	557 MW / 1,349 MWh	557 MW / 1,349 MWh
Total	**0 MW / 0 MWh**	**975 MW / 2,975 MWh**	**975 MW / 2,975 MWh**	**975 MW / 2,975 MWh**	**975 MW / 2,975 MWh**	**975 MW / 2,975 MWh**	**975 MW / 2,975 MWh**

Shown below in Figure 97 and Figure 98 is the impact that the accelerated offshore wind has on the various reliability metrics. While installing 400 MW of offshore wind helps to improve reliability and reduces the unserved energy to around 11 GWh, installing 300-400MW of firm generation shows a larger improvement on reliability and reduces the unserved energy to around 0.3 GWh or less.

Shown in Figure 97 and Figure 99 is the impact that accelerating offshore wind has on the new firm generation needed. With 400 MW of offshore wind, the EUE reliability target is only satisfied with an additional 300 MW of new firm generation. With only 150 MW of new firm generation and 400 MW of offshore wind, none of the reliability targets are met. Even in this scenario with 300 MW of new firm generation, the LOLE target is not met.

Figure 97: Probabilistic analysis - results summary, year 2029. Accelerated Offshore Wind sensitivity

Year 2029	New Firm Generation (MW)	Offshore Wind (MW)	LOLE (Days/Year)	LOLEv (Events/Year)	LOLH (Hours/Year)	EUE (GWH/Year)
Existing (2021)	0	0	1.18	1.30	2.90	0.13
Base_270PVB_0Wnd_ Mar22Out	0	0	54.91	112.08	322.86	51.42
Base_270PVB_400OSW_ Mar22Out	0	400	12.14	21.96	69.56	11.32
Base_300_270PVB_0Wnd_ Mar22Out	300	0	0.66	1.18	2.47	0.26
Base_400_270PVB_0Wnd_ Mar22Out	400	0	0.04	0.05	0.09	0.01
Base_270PVB_400OSW_ Mar22Out	0	400	12.14	21.96	69.56	11.32
Base_150_270PVB_400OSW _Mar22Out	150	400	2.06	3.80	10.35	1.42
Base_300_270PVB_400OSW _Mar22Out	300	400	0.18	0.34	0.74	0.08

Figure 98. EUE and total firm capacity in 2029. Accelerated Offshore Wind sensitivity

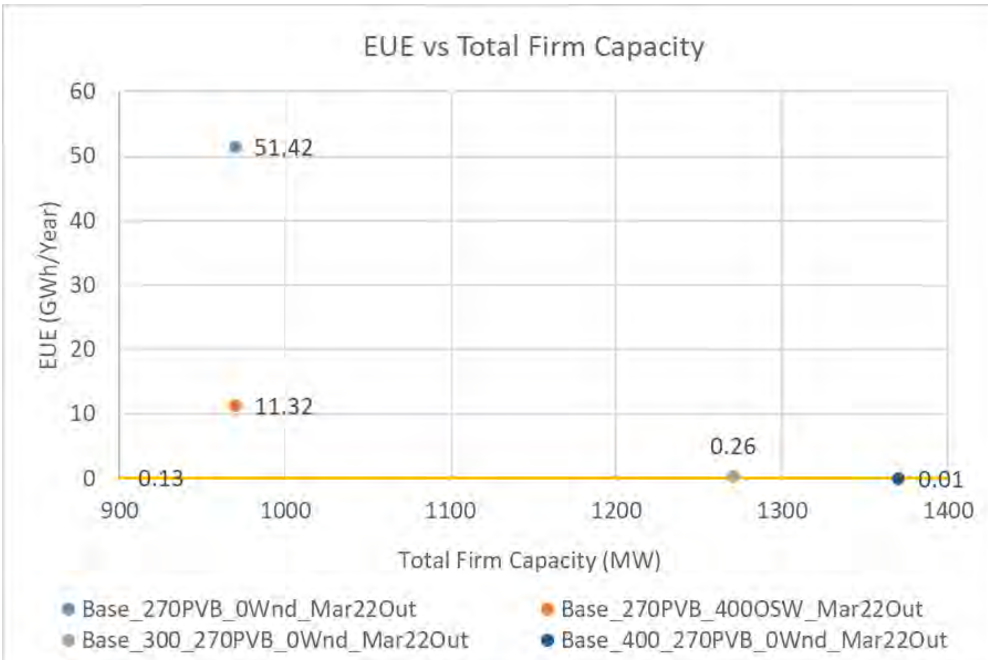
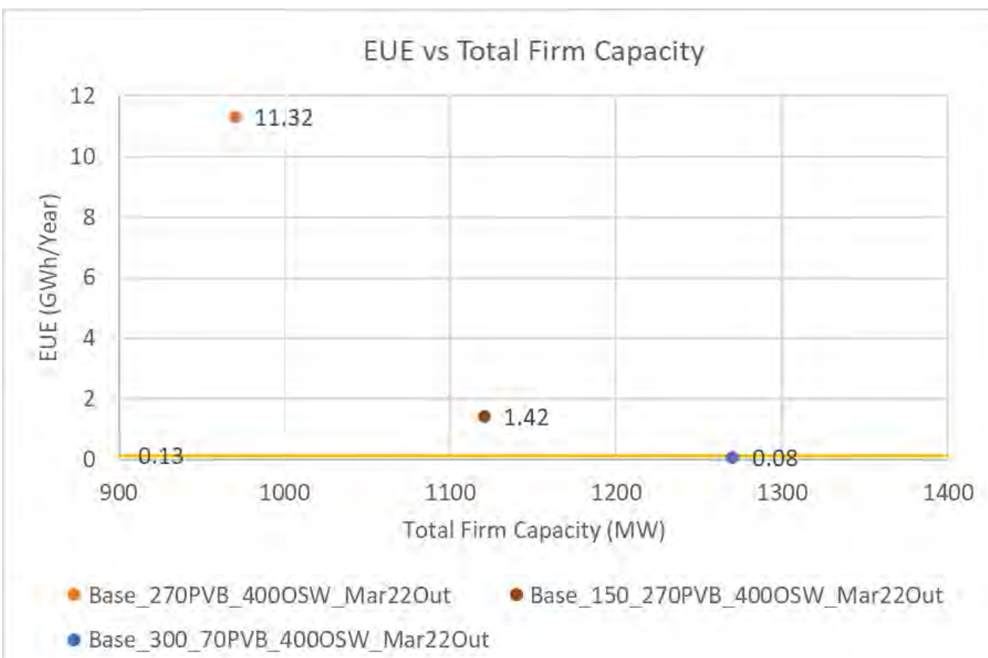


Figure 99. EUE and total firm capacity in 2029. Accelerated Offshore Wind sensitivity cont'd



Shown below in Figure 100 is what one of the worst days could look like for the Base_150_270PVB_400OSW_Mar22Out case where the new generation added consists of only 150MW of new firm generation, 270 MW of new paired renewables, and 400MW of new offshore wind. This day has one of the highest outages of thermal generators and one of the lowest renewable generation. Figure 101 shows the day with the largest amount of available renewable energy.

Figure 100. Sample dispatch for the day with the highest amount of unserved energy. Base_150_270PVB_400OSW_Mar22Out scenario

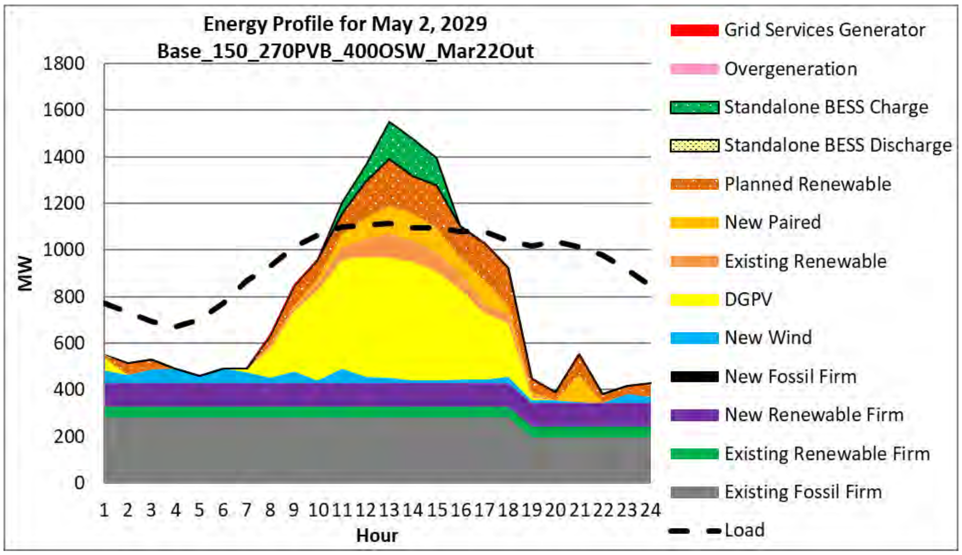
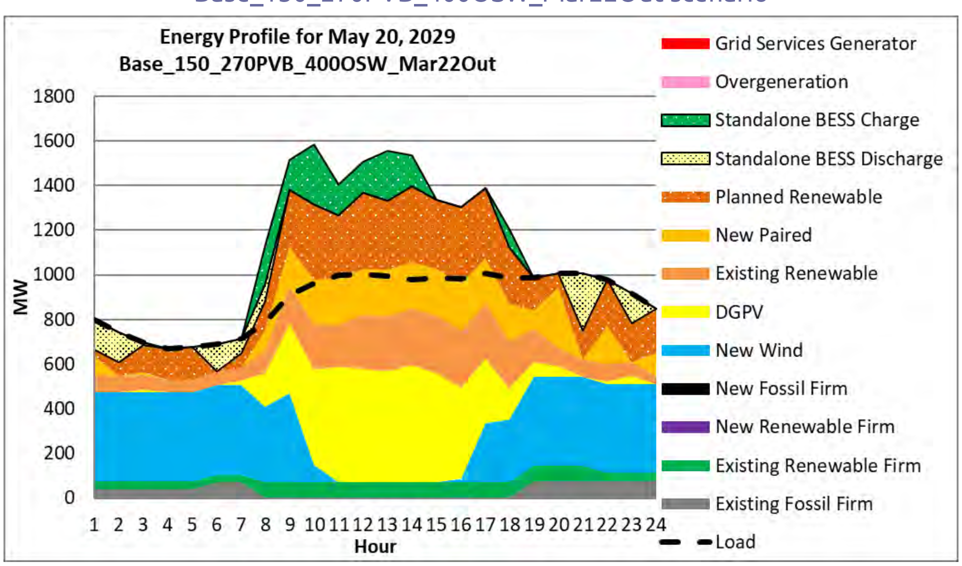


Figure 101. Sample dispatch for the day with the highest amount of available variable renewable generation. Base_150_270PVB_400OSW_Mar22Out scenario



6.5.10 Planning for Extreme Events

Initial analysis was performed to evaluate potential extreme events and their impact on reliability. More work must be done in this area to determine the magnitude and impact an extreme event could have on the system and whether investments should be made to mitigate such events. This analysis, however, provides an initial starting point.

A forced outage caused by an extreme event may last several weeks or longer. This forced outage may be caused by various factors such as transmission line outages, wildfires and supply-chain issues, among other things. Resources were assumed to be out for 438 consecutive hours, or 5% of the year. The assumption to use a 5% outage rate for transmission outages is consistent with the LA100 Renewable Energy Study. The scenarios analyzed were:

- Base_Accel_163WindOut_5pct – Base_Accel case with 438 consecutive hours of forced outage on the 163MW onshore wind.
- Base_Accel_300BESSOut_5pct – Base_Accel case with 438 consecutive hours of forced outage on 300MW/600MWh Standalone BESS. The 2-hour standalone battery duration was determined by RESOLVE.
- Base_Accel_300PVBOut_5pct – Base_Accel case with 438 consecutive hours of forced outage on 300MW paired PV with 300MW/900MWh paired BESS. The 3-hour paired battery duration was determined by RESOLVE.
- Base_Accel_508_Staggered_163WindOut_5pct – Base_Accel_508_Staggered case with 438 consecutive hours of forced outage on the 163MW onshore wind.
- Base_Accel_508_Staggered _300BESSOut_5pct – Base_Accel_508_Staggered case with 438 consecutive hours of forced outage on 300MW/600MWh Standalone BESS. The 2-hour standalone battery duration was determined by RESOLVE.
- Base_Accel_508_Staggered _300PVBOut_5pct – Base_Accel_508_Staggered case with 438 consecutive hours of forced outage on 300MW paired PV with 300MW/900MWh paired BESS. The 3-hour paired battery duration was determined by RESOLVE.
- Base_Accel_508_Staggered_300FirmOut_5pct – Base_Accel_508_Staggered case with 438 consecutive hours of forced outage on the 300MW new firm generation.

Figure 102 shows the impact that the higher outage rates have on the reliability metrics.

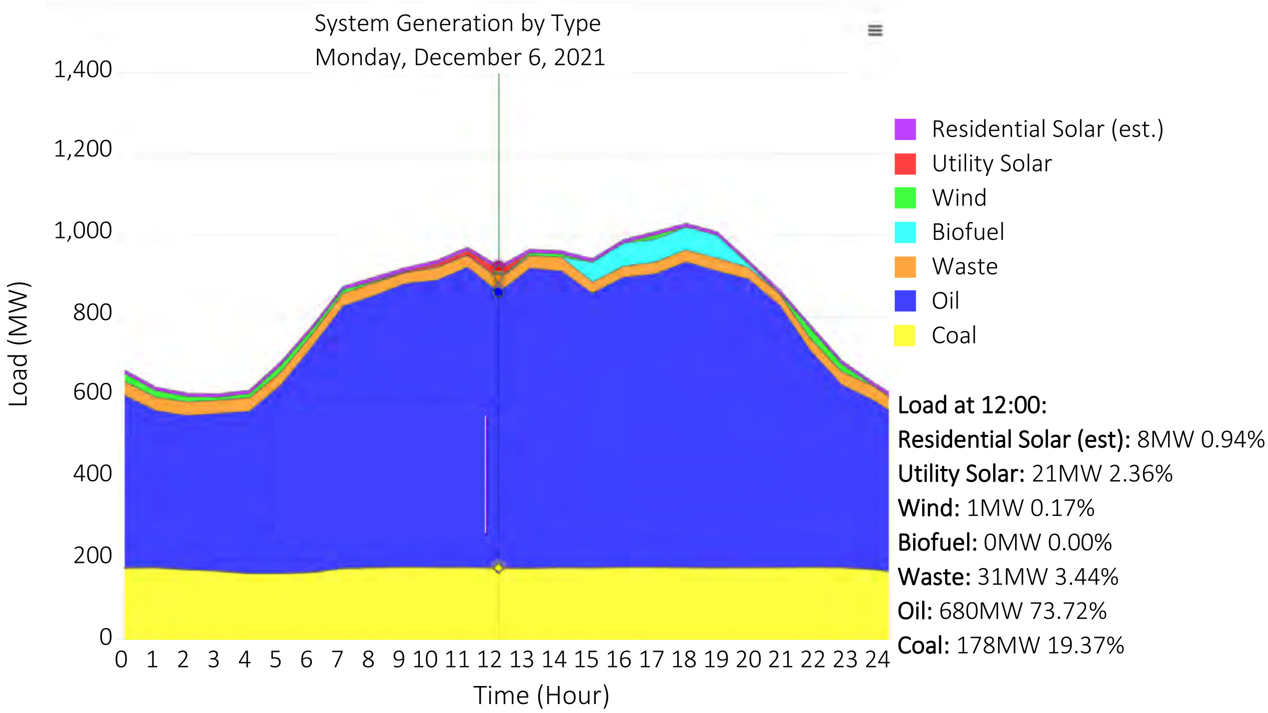
Figure 102. Probabilistic analysis - results summary, year 2029. Base cases sensitivity with extended forced outage

Year 2029	New Firm Generation (MW)	LOLE (Days/Year)	LOLEv (Events/Year)	LOLH (Hours/Year)	EUE (GWH/Year)
Existing (2021)	0	1.18	1.30	2.90	0.13
Base_Accel	0	0.52	1.05	2.01	0.44
Base_Accel_163WindOut_5pct	0	0.50	1.02	1.97	0.44
Base_Accel_300BESSOut_5pct	0	0.53	1.09	1.98	0.44
Base_Accel_300PVBOut_5pct	0	0.54	1.10	2.02	0.45
Base_Accel_508_Staggered	300	0.00	0.00	0.00	0.00
Base_Accel_508_Staggered_163WindOut_5pct	300	0.00	0.00	0.00	0.00
Base_Accel_508_Staggered_300BESSOut_5pct	300	0.00	0.00	0.00	0.00
Base_Accel_508_Staggered_300PVBOut_5pct	300	0.00	0.00	0.00	0.00
Base_Accel_508_Staggered_300FirmOut_5pct	300	0.03	0.06	0.10	0.02

As shown, by comparing the cases with the 300 MW of new firm generation to the cases without, the addition of firm generation eliminated the unserved energy in most cases. Focusing on the cases with the 300 MW of new firm generation, only the case where the firm generation was forced out for 438 consecutive hours showed unserved energy. This highlights the value that firm generation provides to the system. In the cases where the onshore wind, paired PV, or standalone BESS is removed from service, there is no expected unserved energy, indicating the remaining resources were able to adequately meet demand. Only in the case where the new firm resources were removed from service do the results show unserved energy, indicating that the remaining resources were not able to meet demand.

One area that warrants further exploration is the occurrence of poor weather conditions such as the Kona Low experienced on Oʻahu in December 2021. As shown in Figure 103, on December 6, 2021, an unusually low amount of DG-PV, utility scale solar and wind was available on this day. About 92% of the load was supplied by firm generation. In 2030, without sufficient renewable firm generation, it’s possible that there could be insufficient generation to charge energy storage systems and supply the load.

Figure 103. Generation by resource type on December 6, 2021



There are several considerations in evaluating these potentially high impact events:

- The resource adequacy does attempt to account for "extreme events", but the impacts are weighted to the probability of occurrence, thus excluding mitigation measures for tail events. The 80th percentile hourly dependable capacity for renewable resources and probabilistic resource adequacy would not account for these events. Further, by convention, the probabilistic resource adequacy metrics are reported as the average of the total samples.
- The likelihood and negative impact of a tail event is reduced in two ways: increase in probability of generation availability (adding more of a resource, improving outage rates, etc.) and decrease in unavailability overlap (flexible generation, diversification). Risk can be reduced by focusing on only one of these aspects, but the effectiveness of each mitigation is augmented when addressed at the same time. While possible to meet demand with a portfolio comprised of a singular resource type, the repercussions of a tail event will be amplified, especially if the singular resource has a high chance of being collectively unavailable at the same time as is the case with solar.

During this low frequency / high impact event, each subsequent period of poor renewable generation increases the likelihood of a cascading unavailability at a later time. As one of the more flexible resource types, diversification with firm resources reduces the risks of these events by acting as a buffer to absorb the ripple effects caused by low renewable generation and storage with low state of charge.

7 PRODUCTION COST MODELING AND OPERATIONS UNDER THE PROCUREMENT PLAN

The resource adequacy analysis found that 500-700 MW of new renewable firm capacity would provide sufficient reliability over a range of future scenarios. This amount of new firm generation could also facilitate removal or deactivation of older fossil-fuel generating units depending on the system conditions, such as number of new renewable resources and the load forecasts at the time.

To verify the operations under the procurement scenario, production cost simulations were evaluated using a mix of flexible generators and base loaded renewable firm generators to inform how different technologies would be operated.

For the 500 MW target, a 200 MW combined cycle plant (CC) and 6 quick starting 50 MW combustion turbine (CT) generators were added. The 600 MW target added 100 MW of quick starting internal combustion engines (ICE), similar to Schofield Generating Station, and the 700 MW target includes the CC and CTs in the 500 MW target plus a 180-200 MW of base loaded renewable steam generation that could represent repowering of existing fossil-fuel steam generation facilities.

The characteristics of the different renewable firm generators being considered is shown in Figure 104.

Figure 104. Operating characteristics of firm generators

	RE CT	RE CC	RE ICE	RE Steam/Biomass
Max Capacity (MW)	300 MW (50MW x 6 units)	208 MW	99 MW (9 MW x 11 units)	180 MW (20 MW x 9 units)
Min Stable Level per Unit (MW)	13.75 MW	29.07 MW	3.96 MW	8 MW
Ramp Rate (MW/min)	50	50	1.66	2.5
Start Time (min)	5	30	5	5
Capital – 2029 ($/kW)	1,416	1,670	2,988	7,111
Fixed O&M – 2029 ($/kWyr)	31	41	46	224
Variable O&M – 2029 ($/MWh)	7	3	34	7
Fuel – 2029 ($/mmbtu)	Diesel – 18.85 Biodiesel – 37.30	Diesel – 18.85 Biodiesel – 37.30	ULSD – 20.42 Biodiesel – 37.30	Biomass – 4.76 Biodiesel – 37.30

The biomass option has a relatively higher fixed cost than the renewable CT, CC and ICE options. However, because of its lower variable cost, it can be a cost-effective option if the firm capacity is expected to have higher run hours and stable usage. Otherwise, in a situation where the firm capacity acts more as a standby capacity that may not run often, the CT, CC and ICE could be more cost effective.

7.1 Operations under the Procurement Plan

As discussed in Section 6.2.2, firm capacity between 508 MW and 688 MW would address most of the capacity shortfall requirements. A production simulation was performed in PLEXOS using the Base staggered resource plans provided in Figure 129 and the Land Constrained staggered resource plans provided in

Figure 130 to determine how the new firm units would operate. One set of simulations assumed the new CT, CC, and ICE units were on biofuel, and a separate set of simulations assumed the new CT, CC, and ICE units were on fossil-fuel.

As shown in the following sections, even in the cases where the new firm units are on biofuel, they will still operate. Given the significantly higher cost of biofuel over fossil-fuel, this indicates the value these units provide to the system to meet demand, even when they are on biofuel. Furthermore, since the new units are more efficient than the current fleet of firm generators, when the new units are on fossil-fuel rather than biofuel, they operate significantly more. As a result, whether the new units are on biofuel or fossil-fuel, they will provide value to the system either through providing capacity to meet demand or through better efficiency compared to existing generators.

As shown below, the simulations still project large amounts of variable renewable generation being used to meet load, even with the addition of new firm generation. The simulations also project that even in the Land Constrained cases, which have the least amount of renewables added, the RPS-A is projected to be over 50% by 2030.

7.1.1 Characteristics – Capacity Factor

Shown below in Figure 105 is the capacity factor for the new firm resources in each of the Base staggered resource plans and Figure 106 is the capacity factor for the existing firm generators in the Base_508_Staggered case.

Figure 105. Capacity factor of new firm units in Base (staggered) cases

Capactiy Factor (%)	Base_508 Staggered		Base_607 Staggered			Base_688 Staggered		
Year	RE CT	RE CC	RE CT	RE ICE	RE CC	RE CT	BioM	RE CC
2025	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2026	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2027	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2028	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2029	12%	N/A	4%	26%	N/A	1%	97%	N/A
2030	5%	N/A	2%	10%	N/A	0%	76%	N/A
2031	5%	N/A	2%	8%	N/A	0%	73%	N/A
2032	4%	N/A	1%	8%	N/A	0%	72%	N/A
2033	0%	10%	0%	2%	11%	0%	69%	1%
2034	1%	8%	0%	2%	9%	0%	66%	1%
2035	0%	6%	0%	1%	6%	0%	59%	0%

Figure 106. Capacity factor of existing firm units in Base_508_Staggered case

Capacity Factor (%)	Existing Thermal Capacity Factor Base_508_Staggered								
Year	CIP1	DSG	SCH 1	Kahe 1	Kahe 2	Kahe 3	Kahe 4	Kahe 5	Kahe 6
2025	5.59	6.85	1.26	69.12	59.63	41.36	63.30	14.77	16.91
2026	11.12	12.63	2.52	57.81	61.42	47.33	67.14	9.91	3.08
2027	2.08	2.75	6.32	27.82	51.73	18.75	61.03	9.48	7.60
2028	2.85	3.07	9.19	44.00	49.03	27.57	52.46	3.03	2.42
2029	14.54	4.81	61.79	N/A	N/A	77.54	87.94	21.94	9.57
2030	4.77	1.52	25.86	N/A	N/A	10.61	33.80	1.36	0.57
2031	5.43	0.75	25.59	N/A	N/A	10.76	31.25	0.46	1.03
2032	4.38	0.91	23.78	N/A	N/A	9.19	32.10	3.10	0.23
2033	1.79	0.29	30.43	N/A	N/A	23.25	40.79	8.84	0.52
2034	1.60	0.41	29.14	N/A	N/A	21.59	38.39	5.85	0.95
2035	1.42	0.32	23.07	N/A	N/A	17.02	32.49	2.03	0.26

Figure 107. Capacity factor of existing firm units in Base_508_Staggered case cont'd

Capacity Factor (%)	Existing Thermal Capacity Factor Base_508_Staggered					
Year	Waiau 5	Waiau 6	Waiau 7	Waiau 8	Waiau 9	Waiau 10
2025	27.43	21.45	69.44	65.42	17.39	9.67
2026	38.90	27.98	60.68	62.88	15.05	12.96
2027	N/A	N/A	64.32	62.47	11.18	4.10
2028	N/A	N/A	66.45	64.30	14.50	6.74
2029	N/A	N/A	76.02	71.60	66.71	51.65
2030	N/A	N/A	32.78	36.15	24.56	20.48
2031	N/A	N/A	33.05	29.23	22.40	18.51
2032	N/A	N/A	31.96	28.92	19.10	16.42
2033	N/A	N/A	N/A	N/A	25.69	18.92
2034	N/A	N/A	N/A	N/A	24.35	18.55
2035	N/A	N/A	N/A	N/A	18.52	14.47

Shown below in Figure 108 is the capacity factor for the new firm resources in each of the Land Constrained staggered resource plans and Figure 109 is the capacity factor for the existing firm generators in the LC_508_Staggered case.

Figure 108. Capacity factor of new firm units in Land Constrained (staggered) cases

Capacity Factor (%)	LC_508_Staggered		LC_607_Staggered			LC_688_Staggered		
Year	RE CT	RE CC	RE CT	RE ICE	RE CC	RE CT	BioM	RE CC
2025	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2026	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2027	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2028	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2029	24%	N/A	10%	44%	N/A	4%	97%	N/A
2030	13%	N/A	6%	21%	N/A	3%	95%	N/A
2031	13%	N/A	6%	23%	N/A	2%	96%	N/A
2032	23%	N/A	12%	36%	N/A	5%	96%	N/A
2033	11%	56%	4%	23%	50%	1%	96%	24%
2034	12%	57%	5%	27%	50%	2%	96%	24%
2035	3%	31%	1%	9%	28%	0%	89%	11%

Figure 109. Capacity factor of existing firm units in LC_508_Staggered case

Capacity Factor (%)	Existing Thermal Capacity Factor LC_508_Staggered								
Year	CIP1	DSG	SCH 1	Kahe 1	Kahe 2	Kahe 3	Kahe 4	Kahe 5	Kahe 6
2025	6.00	6.68	1.09	69.14	59.65	41.08	63.08	14.79	16.76
2026	10.92	11.68	2.30	58.60	61.25	47.38	67.06	9.93	3.11
2027	4.67	5.41	10.53	52.81	62.21	49.44	70.21	10.26	5.32
2028	3.73	3.91	11.85	61.57	59.80	51.11	59.24	5.08	13.61
2029	22.68	5.02	77.84	N/A	N/A	81.90	90.17	23.26	16.46
2030	8.93	2.88	49.93	N/A	N/A	73.21	82.77	22.96	25.52
2031	11.19	2.41	60.84	N/A	N/A	83.21	77.34	11.98	21.60
2032	17.50	8.00	72.42	N/A	N/A	65.13	86.68	14.57	2.42
2033	15.42	2.64	86.15	N/A	N/A	86.59	85.35	24.07	9.08
2034	16.17	2.93	86.41	N/A	N/A	88.50	79.26	15.77	19.42
2035	6.25	1.12	68.10	N/A	N/A	70.58	81.73	10.07	15.55

Figure 110. Capacity factor of existing firm units in LC_508_Staggered case cont'd

Capacity Factor (%)	Existing Thermal Capacity Factor LC_508_Staggered					
Year	Waiau 5	Waiau 6	Waiau 7	Waiau 8	Waiau 9	Waiau 10
2025	27.09	21.30	69.54	65.63	16.98	10.07
2026	40.14	28.08	60.15	62.81	14.53	12.59
2027	N/A	N/A	73.22	69.59	19.32	7.83
2028	N/A	N/A	73.64	70.54	20.24	10.14
2029	N/A	N/A	77.35	73.80	80.38	69.35
2030	N/A	N/A	79.81	81.53	50.06	36.85
2031	N/A	N/A	87.78	87.39	53.47	43.51
2032	N/A	N/A	74.42	77.12	56.75	56.67
2033	N/A	N/A	N/A	N/A	76.80	63.03
2034	N/A	N/A	N/A	N/A	75.90	69.28
2035	N/A	N/A	N/A	N/A	57.37	47.38

The new CC, SC, and ICE units were assumed to be on biodiesel while existing steam units located at Kahe and Waiau were assumed to be on low-sulfur fuel oil (LSFO). As expected, due to the higher cost of biodiesel compared to LSFO, the new CC, SC, and ICE units had lower utilization and were primarily used as standby capacity; a critical function that these generators serve to mitigate the risks of weather dependent resources. The biomass fuel cost was based on the 2021 NREL Annual Technology Baseline, which was significantly lower than the LSFO fuel cost assumed. As a result, the biomass generator ran considerably more. As the existing generators are deactivated, the capacity factor of the remaining generators increases, which suggests greater burden on the old existing generators, which may lead to increasing outage rates and worsening reliability.

The same production simulations were performed, this time assuming the new CC and SC were on diesel and the new ICE was on ultra-low sulfur diesel (ULSD). This illustrates how units would be dispatched if all generators were using the same fuel type. This does not imply that the new firm generators acquired would necessarily be operated on diesel fuel. Shown below in Figure 111 is the capacity factor for the new firm resources in each of the Base staggered resource plans when the new CC, SC and ICE are fueled by diesel.

Figure 111. Capacity factor of new firm units in Base (staggered fossil) cases

Capacity Factor (%)	Base_508 Staggered_Fossil		Base_607 Staggered_Fossil			Base_688 Staggered_Fossil		
Year	CT	CC	CT	ICE	CC	CT	BioM	CC
2025	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2026	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2027	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2028	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2029	47%	N/A	29%	73%	N/A	14%	97%	N/A
2030	19%	N/A	12%	52%	N/A	3%	76%	N/A
2031	17%	N/A	10%	49%	N/A	1%	73%	N/A
2032	16%	N/A	10%	47%	N/A	1%	72%	N/A
2033	2%	53%	0%	12%	52%	0%	69%	12%
2034	2%	48%	0%	11%	47%	0%	66%	9%
2035	1%	38%	0%	4%	38%	0%	59%	5%

Figure 112. Capacity factor of existing firm units in Base_508_Staggered_Fossil case

Capacity Factor (%)	Existing Thermal Capacity Factor Base_508 Staggered_Fossil								
Year	CIP1	DSG	SCH 1	Kahe 1	Kahe 2	Kahe 3	Kahe 4	Kahe 5	Kahe 6
2025	5.79	6.61	1.23	68.79	59.57	41.46	63.17	14.75	16.90
2026	11.03	12.40	2.43	57.99	61.13	47.13	67.08	9.91	3.09
2027	2.31	2.58	6.23	26.50	50.35	20.22	61.22	9.54	7.96
2028	3.05	2.68	9.26	42.48	50.20	27.60	52.73	2.98	1.09
2029	1.29	0.78	3.76	N/A	N/A	73.23	86.37	21.64	10.80
2030	0.70	0.92	3.30	N/A	N/A	10.16	32.78	1.35	0.90
2031	0.79	0.69	3.43	N/A	N/A	9.66	31.40	0.41	0.86
2032	0.36	0.45	2.87	N/A	N/A	9.10	30.10	3.03	0.94
2033	0.03	0.01	0.28	N/A	N/A	5.31	9.20	0.29	0.31
2034	0.03	0.00	0.38	N/A	N/A	5.75	7.61	1.07	0.51
2035	0.01	0.00	0.06	N/A	N/A	1.88	7.09	0.47	0.02

Figure 113. Capacity factor of existing firm units in Base_508_Staggered_Fossil case cont'd

Capacity Factor (%)	Existing Thermal Capacity Factor Base_508 Staggered_Fossil					
Year	Waiau 5	Waiau 6	Waiau 7	Waiau 8	Waiau 9	Waiau 10
2025	28.05	20.45	69.94	65.34	17.35	9.43
2026	40.91	28.62	60.49	62.67	14.61	12.56
2027	N/A	N/A	63.32	62.83	11.92	4.48
2028	N/A	N/A	67.76	64.35	14.95	6.88
2029	N/A	N/A	75.46	71.05	6.18	2.70
2030	N/A	N/A	36.06	31.28	2.47	1.08
2031	N/A	N/A	33.06	31.02	2.31	1.39
2032	N/A	N/A	30.99	26.92	1.54	1.35
2033	N/A	N/A	N/A	N/A	0.14	0.21
2034	N/A	N/A	N/A	N/A	0.18	0.08
2035	N/A	N/A	N/A	N/A	0.03	0.00

Shown below in Figure 114 is the capacity factor for the new firm resources in each of the Land Constrained staggered resource plans when the new CC, SC and ICE are on fossil-fuel.

Figure 114. Capacity factor of new firm units in Land Constrained (staggered fossil) cases

Capacity Factor (%)	LC_508 Staggered_Fossil		LC_607 Staggered_Fossil			LC_688 Staggered_Fossil		
Year	CT	CC	CT	ICE	CC	CT	BioM	CC
2025	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2026	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2027	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2028	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2029	65%	N/A	51%	81%	N/A	28%	97%	N/A
2030	38%	N/A	28%	65%	N/A	19%	96%	N/A
2031	44%	N/A	29%	64%	N/A	19%	96%	N/A
2032	55%	N/A	41%	69%	N/A	23%	96%	N/A
2033	39%	94%	24%	63%	94%	16%	96%	81%
2034	40%	93%	24%	64%	93%	18%	96%	81%
2035	24%	82%	16%	59%	82%	7%	89%	64%

Figure 115. Capacity factor of existing firm units in LC_508_Staggered_Fossil case

Capacity Factor (%)	Existing Thermal Capacity Factor LC 508 Staggered Fossil								
Year	CIP1	DSG	SCH 1	Kahe 1	Kahe 2	Kahe 3	Kahe 4	Kahe 5	Kahe 6
2025	5.31	6.40	1.15	70.35	59.55	40.84	63.13	14.84	16.95
2026	10.72	11.94	2.47	59.17	61.00	47.37	67.08	9.91	3.03
2027	3.38	3.36	7.07	48.23	61.71	43.40	67.75	10.28	23.31
2028	4.01	4.10	12.68	61.74	59.82	48.48	59.04	4.79	13.68
2029	4.39	4.30	13.69	N/A	N/A	79.01	88.74	22.64	14.58
2030	1.51	1.36	7.21	N/A	N/A	69.41	80.85	22.65	24.70
2031	1.29	1.01	7.55	N/A	N/A	76.49	75.03	11.37	20.40
2032	5.30	5.81	15.30	N/A	N/A	60.64	84.57	14.25	2.74
2033	0.98	0.91	4.68	N/A	N/A	67.68	72.69	20.41	7.44
2034	1.44	0.97	7.13	N/A	N/A	69.77	68.97	13.41	15.85
2035	0.34	0.21	1.59	N/A	N/A	32.99	55.21	3.48	4.04

Figure 116. Capacity factor of existing firm units in LC_508_Staggered_Fossil case cont'd

Capacity Factor (%)	Existing Thermal Capacity Factor LC_508 Staggered_Fossil					
Year	Waiau 5	Waiau 6	Waiau 7	Waiau 8	Waiau 9	Waiau 10
2025	27.89	21.10	69.62	65.95	16.26	8.91
2026	40.36	27.71	60.31	62.77	14.64	12.57
2027	N/A	N/A	70.59	66.84	13.68	4.25
2028	N/A	N/A	73.63	71.21	20.84	11.16
2029	N/A	N/A	77.30	73.79	19.60	10.31
2030	N/A	N/A	78.89	80.11	8.48	3.92
2031	N/A	N/A	87.55	86.61	7.15	3.24
2032	N/A	N/A	73.57	76.07	12.26	10.25
2033	N/A	N/A	N/A	N/A	3.07	1.30
2034	N/A	N/A	N/A	N/A	4.96	2.98
2035	N/A	N/A	N/A	N/A	1.21	0.54

In the simulations where the new CC and CT were assumed to be on diesel and the new ICE was assumed to be on ultra-low sulfur diesel, the firm units run considerably more because the cost of fuel is relatively similar to existing generators as opposed to the relatively higher price of biofuel assumed in the renewable fuel production simulations.

7.1.2 Characteristics – Daily Dispatch Chart

Shown below in Figure 117 is the dispatch of the new firm renewables for a high renewable day in 2029, 2030, and 2033 for the Base_508_Staggered case. Shown below Figure 118 is the dispatch of the new firm renewables for a low renewable day in 2029, 2030, and 2033 for the Base_508_Staggered case.

In the daily charts, resources listed as "New" were resources selected by RESOLVE, Planned Renewables are renewable resources that are not yet in service but are expected to come into service by 2025, and Existing Renewables are renewables that are currently in service. The "Load" line is the system load without the charging of any energy storage. Any generation above the "Load" line is energy that goes into an energy storage system. Overgeneration is remaining no-cost capacity that does not go into meeting any of the system load or energy storage systems.

As shown in the figures below, in 2029, the new firm renewable generators are needed regardless if it is a high or low renewable day. Also, on low-renewable days, the new firm renewable generators are needed in 2033, even with the large number of renewables added in prior years.

Figure 117. Daily chart – Base_508_Staggered scenario – High-renewable day

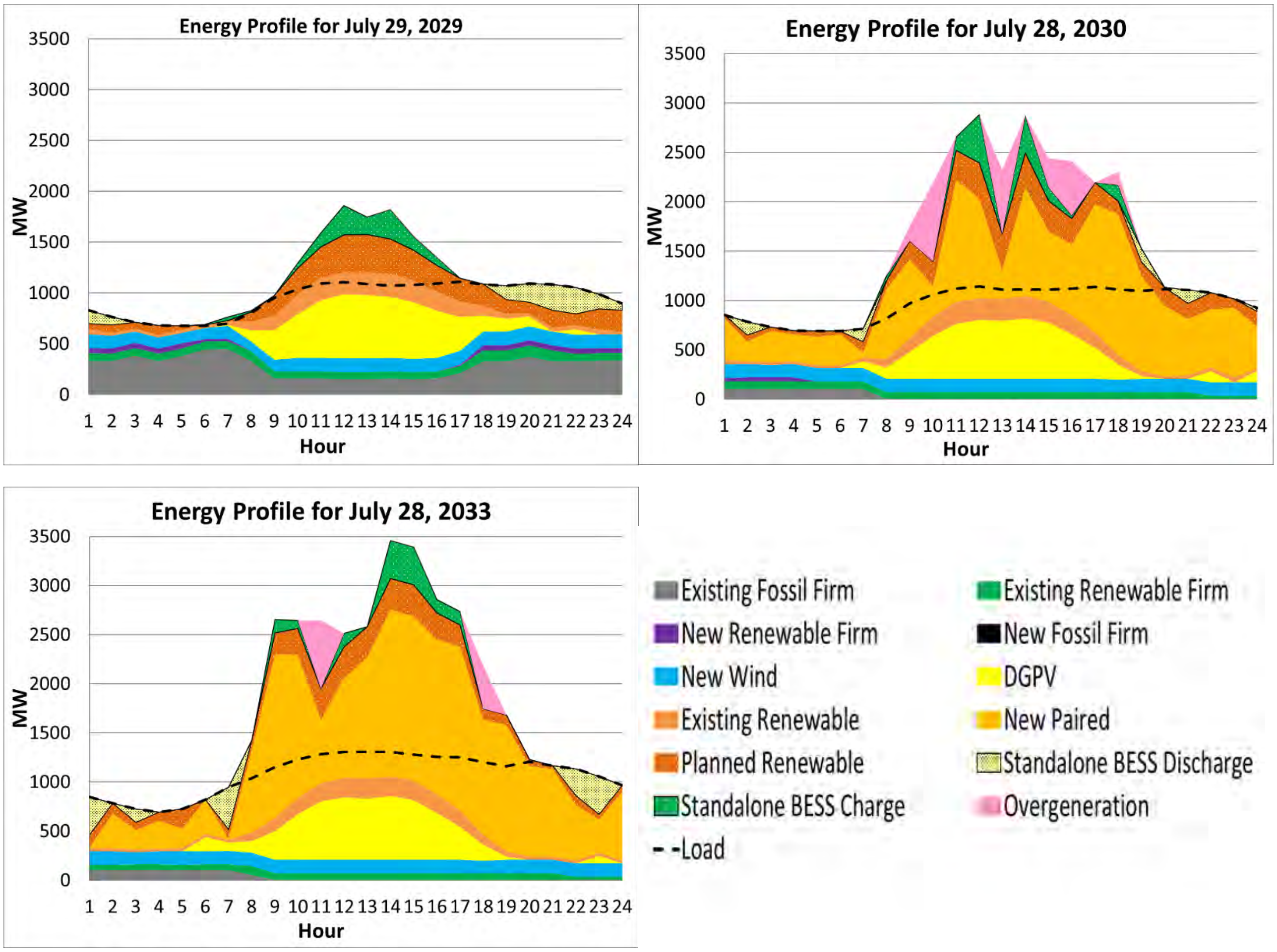
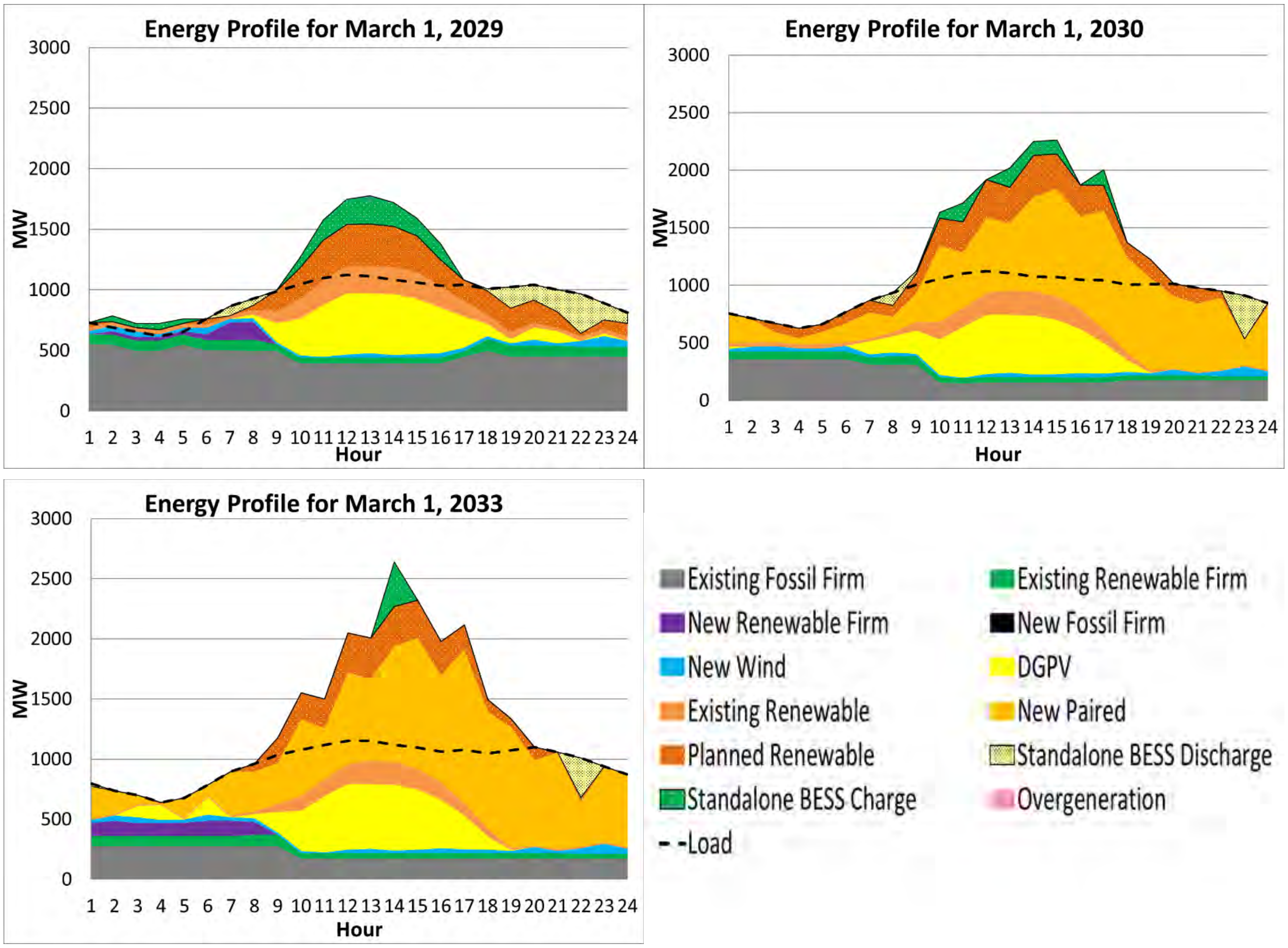


Figure 118. Daily chart – Base_508_Staggered scenario – Low-renewable day



Shown below in Figure 119 is the dispatch for a high-renewable day in 2029, 2030 and 2033 for the Base_508_Staggered_Fossil scenario, where the new firm resource is on fossil-fuel. Shown below in Figure 120 is the dispatch for a low renewable day in 2029, 2030 and 2033 for the Base_508_Staggered_Fossil scenario, where the new firm resource is on fossil-fuel. As shown in the figures below, when the new firm generators are on fossil-fuel, they are expected to operate significantly more than when they are on biofuel. This is driven by the almost 50% reduction in price for diesel when compared to biodiesel. Despite the higher utilization of the new firm resources, there is still a significant amount of variable renewable generation that will be used to serve load.

Figure 119. Daily chart – Base_508_Staggered_Fossil scenario – High-renewable day

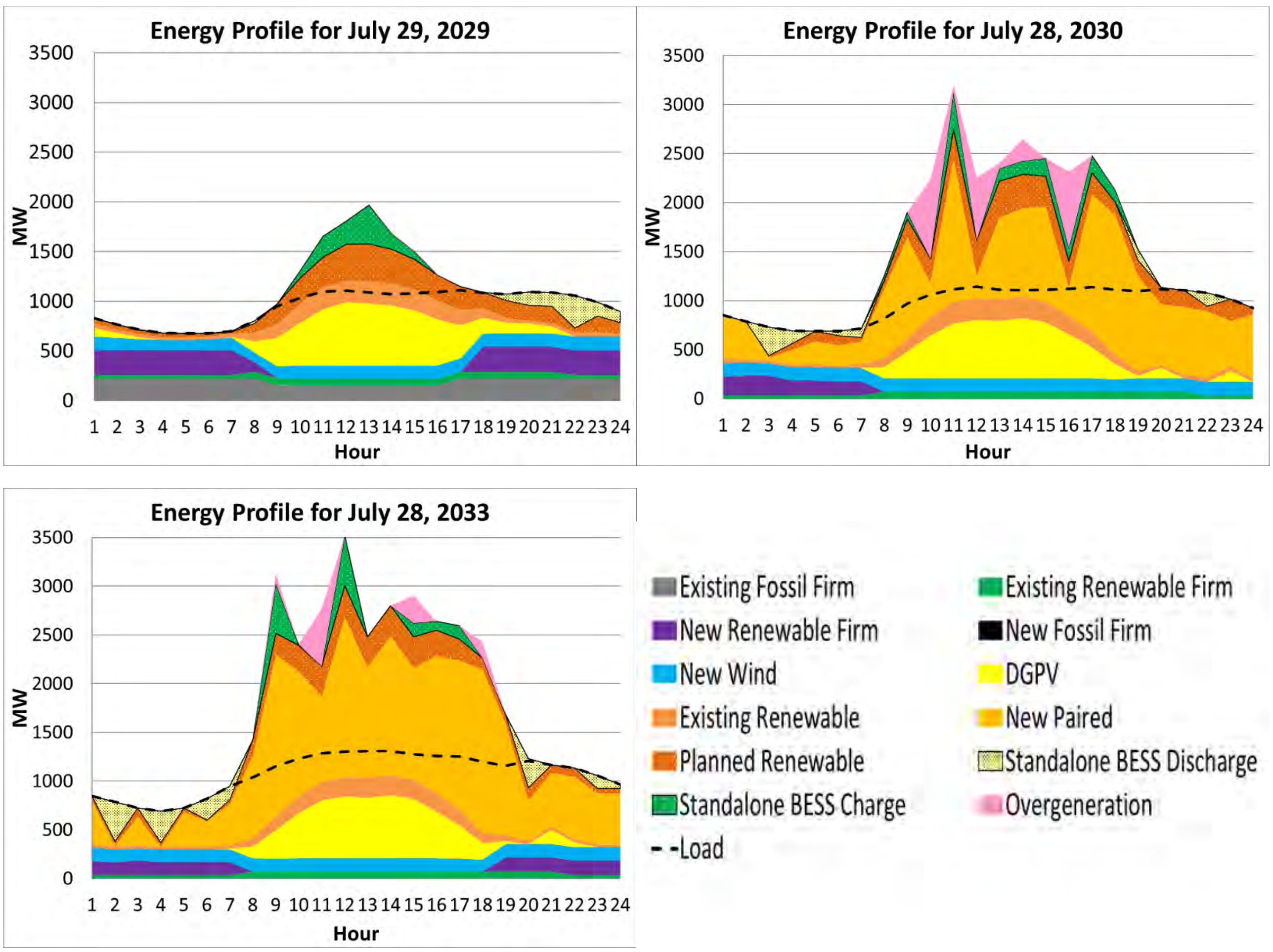
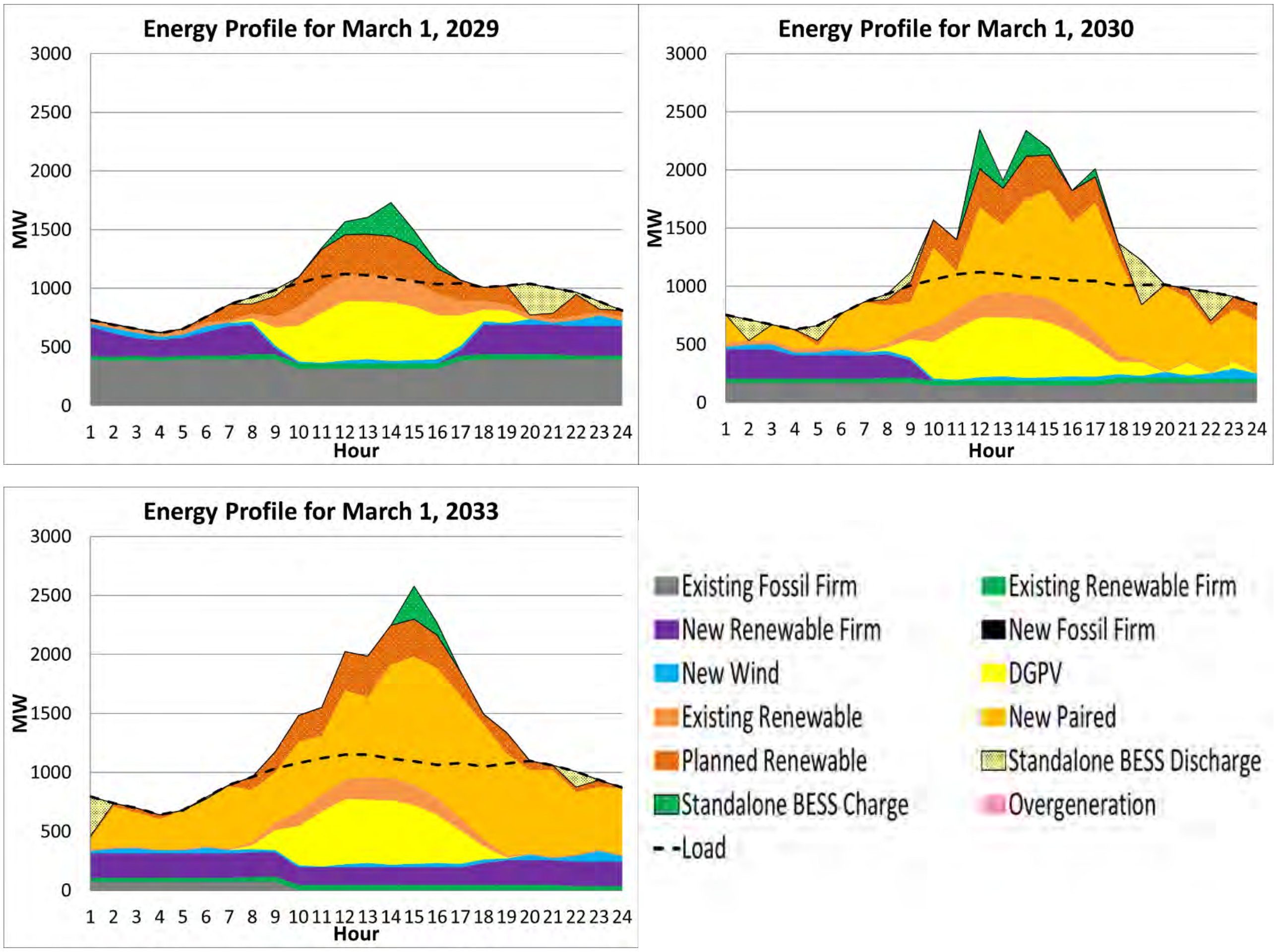


Figure 120. Daily chart – Base_508_Staggered_Fossil scenario – Low-renewable day



7.1.3 Results – RPS-A

Shown below in Figure 121 and Figure 122 is the RPS-A for each of the Base staggered resource plans and Land Constrained staggered resource plans, respectively. The darker columns are the case where the new firm resources were assumed to be on biofuel and the lighter columns are the cases where the new firm resources were assumed to be on fossil-fuel. RPS-A is consistent with the recent amended RPS definition after Governor Ige signed Act 240 (HB2089).

Figure 121. RPS-A for the Base (staggered) scenarios

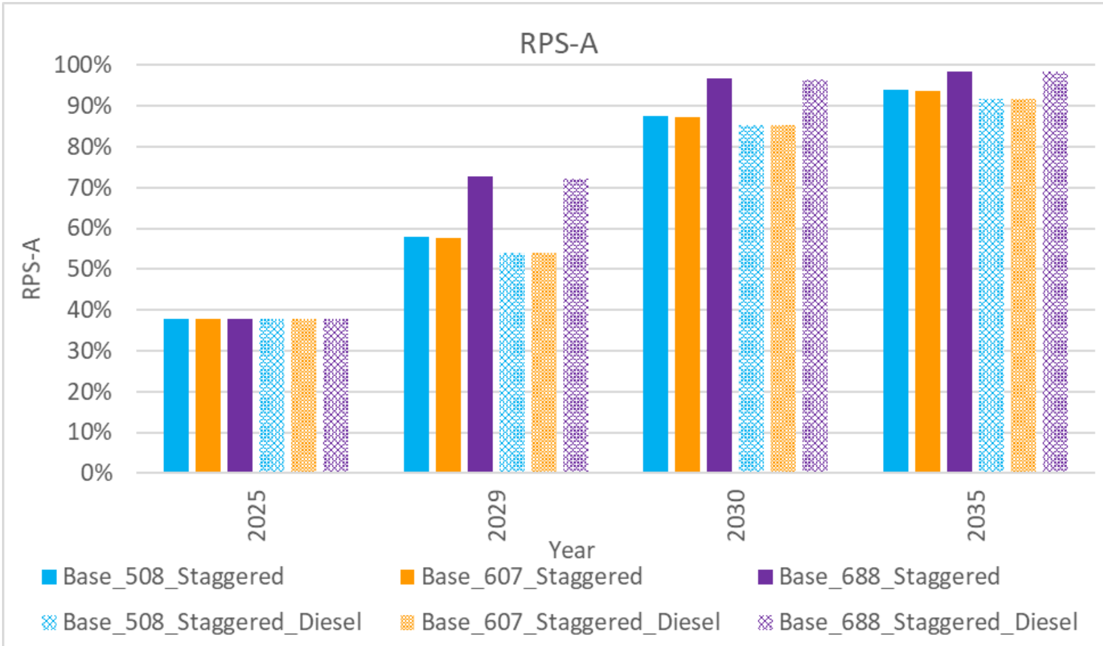
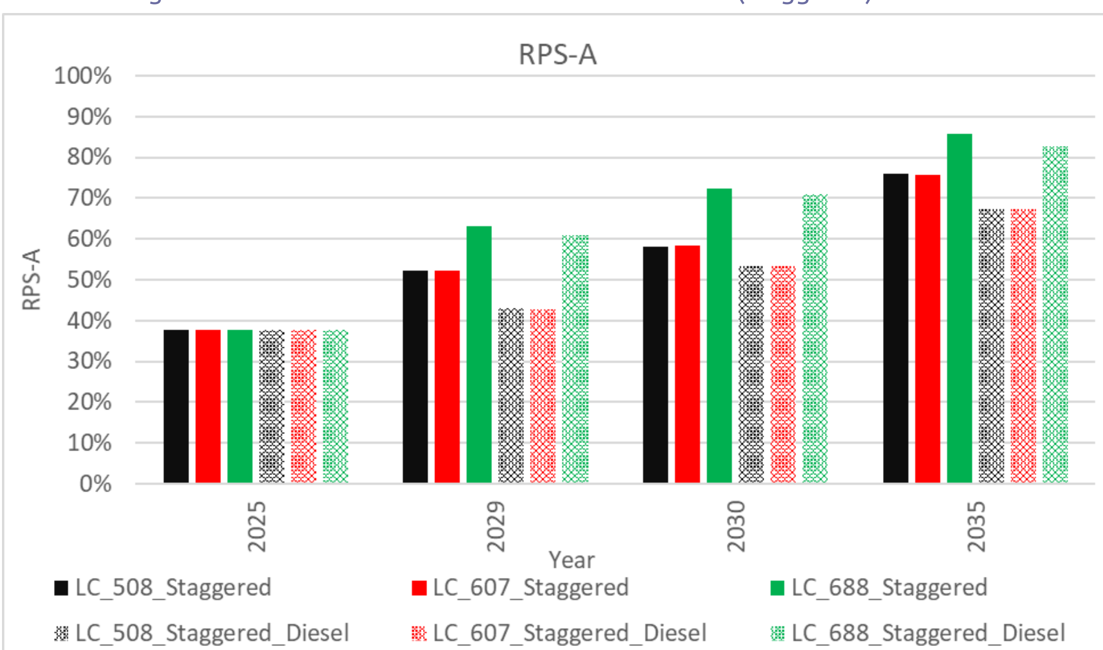


Figure 122. RPS-A for each of the Land Constrained (staggered) scenarios



In the cases where a firm biomass is added, the RPS-A is noticeably higher than the cases where only CT/CC/ICE are added. Also, the Base staggered cases achieve a noticeably higher RPS-A than the Land Constrained staggered cases due to the large amounts of renewables that are added to the system in the Base staggered cases.

7.1.4 Results – Relative NPV

Shown below in Figure 123 is a comparison of the estimated NPV in 2021$ for each of the Base staggered resource plans for 2025-2035 and in Figure 124 is a comparison of the estimated NPV in 2021$ for each of the Land Constrained staggered resource plans for 2025-2035. The cost includes revenue requirements for fuel, variable and fixed O&M, capacity and energy payments for IPP, and capital.

Figure 123. Relative NPV for the Base (staggered) scenarios

	% Difference Relative to Base_508 Staggered (NPV 2025 2035)	NPV 2025 2035 (2021$, 000)
Base_508_Staggered	100%	$8,173,179
Base_607_Staggered	101%	$8,268,483
Base_688_Staggered	100%	$8,145,437
Base_508_Staggered_Fossil	97%	$7,944,130
Base_607_Staggered_Fossil	99%	$8,069,383
Base_688_Staggered_Fossil	99%	$8,101,986

Figure 124. Relative NPV for the Land Constrained (staggered) scenarios

	% Difference Relative to LC 508 Staggered (NPV 2025 2035)	NPV 2025 2035 (2021$, 000)
LC_508_Staggered	100%	$9,156,864
LC_607_Staggered	101%	$9,228,775
LC_688_Staggered	94%	$8,614,233
LC_508_Staggered_Fossil	93%	$8,538,185
LC_607_Staggered_Fossil	94%	$8,583,024
LC_688_Staggered_Fossil	91%	$8,328,604

When the new CT, CC, and ICE are on biofuel, the NPV increases. This occurs because the high cost of biofuel causes low utilization of these resources, and as a result, they are primarily on standby. The addition of biomass, however, causes the NPV to decrease. This is due to the low fuel cost of biomass that was provided in the 2021 NREL Annual Technology Baseline, and as a result, the biomass offsets some of the generation provided by the existing generators on more expensive fossil-fuel.

When the new CT, CC, and ICE are on fossil-fuel, however, the NPV decreases. This occurs because the better efficiency of the new CT, CC, ICE causes greater utilization of these resources, and as a result, their addition offsets some of the generation provided by the existing generators. In the Base case with the large amount of renewable energy already being added, more firm generation added to the system causes the NPV to increase.

8 RECOMMENDED ACTIONS AND NEXT STEPS

Continue to displace fossil-fuel through acquisition of low cost, low carbon renewable energy, starting with 544 GWh through the Stage 3 RFP in Docket No. 2017-0352.

The Grid Needs Assessment provides consistent findings across multiple futures – if renewable energy can be acquired at a low cost, such resources should be pursued in alignment with efforts to reduce carbon emissions by 70% by 2030. The grid needs assessment indicates that 544 GWhs of renewable dispatchable generation in 2027 is needed to offset energy previously provided by the AES coal plant and provide a market test of the remaining, developable renewable potential that can be put into service by 2027.

Continue to pursue customer adoption of DER through new programs and advanced rate design, consistent with the outcomes of the DER Docket No. 2019-0323.

The Grid Needs Assessment demonstrates the necessity of DER to achieve 70% greenhouse gas reductions by 2030, to reduce grid-scale resource needs, and contribute to resource adequacy. Programs and advanced rate designs should provide cost-effective incentives to encourage or accelerate adoptions of these resources.

Pursue generation modernization as soon as practicable to improve operational flexibility and mitigate present reliability risks. Firm renewable generation needs include 300-500 MW of in 2029, and another 200 MW in the 2033 timeframe, starting with the Stage 3 RFP in Docket No. 2017-0352.

The current steam generation fleet on Oʻahu has served the community well beyond its expected life and is now operated as a flexible generator, a role it was not designed for. Thus, in recent years, the availability of those generators continues to decrease, which directly impacts reliability. As recent experience has demonstrated, when resources are needed to fulfill reliability needs on a short timeframe or in emergency situations, options are limited to measures such as customer programs and backup diesel generators. Customer programs, while effective, have shown they take time to ramp up even when significant premiums and incentives are offered, and backup diesel generators may not have long-term grid or environmental value. Reliability analysis completed as part of the grid needs assessment demonstrates that 500-700 MW is a "least regrets" range of firm capacity generation across multiple future scenarios and could allow a significant reduction in dependency on older fossil-fuel generators. New renewable firm generation will also diversify the resource portfolio that is currently heavy with solar and susceptible to severe weather events.

Pursue development of renewable energy zones to facilitate interconnection of additional renewable energy.

The grid needs assessment found that partial or full buildout of certain renewable energy zones could be cost-effective if paired with low-cost renewable energy resources. Renewable energy zones will be needed to maintain transmission reliability, harvest solar and wind resources and transmit them to the load center. Community and commercial interests should be engaged to determine the viability of enabling renewable energy zones for timely development as part of the next competitive procurement for renewable energy following the expected Stage 3 RFP.

Consider procurement of energy efficiency to accelerate adoption in amounts up to the forecasted target to reduce supply side needs.

Significant energy efficiency is forecasted over the next 10 years. Aggressive acquisition of cost-effective energy efficiency measures, greater than what has been acquired historically, should be pursued to reduce supply-side needs and add diversity to the resource portfolio. A procurement of EE from energy service providers could potentially accelerate adoption in parallel to on-going programmatic efforts.

Continue to pursue managed EV charging programs, time-of-use rates, DER, and energy efficiency.

Continued pursuit of flexible management of customer resources, building upon programs such as battery bonus, grid services agreements with aggregators, electric bus time-of-use rates and residential and commercial time-of-use rates. Efforts should continue to attract customer participation to adopt technologies that can support grid management balanced with the cost of operating the grid and the allocation of those costs.

Incorporate system security and system stability analyses, which may yield additional resource needs to mitigate risks associated with a high renewable energy system.

The next iteration of the Oʻahu Grid Needs Assessment will include system security analysis within the IGP process. System security will be critical to realizing a decarbonized grid to ensure that the appropriate essential reliability services are in place to operate a system dominated by inverter-based resources (solar, wind, battery energy storage). The output from the system security study analysis will confirm whether the system under future expansion has any transmission planning criteria violation(s). Violations can be steady state (e.g., steady state voltage, equipment thermal loading, steady state voltage stability, and voltage and current harmonics) or dynamic stability (e.g., excessive under frequency load shedding, undamped oscillation), and may be identified as temporary in nature (e.g., only exists under extreme dispatch scenario) or permanent (e.g., could happen every day).

System security measures include, but are not limited to, proven grid-forming inverters, improving legacy and first-generation advanced inverter trip-and ride-through settings, including EV batteries. These measures will support and improve system stability, synchronous condensers and improved underfrequency load shedding. Example mitigations are provided in the table below.

Examples of Mitigation Solutions Required by System Security Analysis
• Install traditional wire solutions (e.g. reconductor, cable replacement, add transformers to increase steady state capacity, add cap banks)
• Add synchronous condensers, STATCOM to address dynamic voltage support and increase short circuit current
• Short duration, temporary curtailment of a non-GFM resource
• Short duration, temporary charge of grid-scale GFM BESS and increase rotating machine generation
• Short duration, temporary increase in generation at certain locations to provide voltage support
• Install additional centralized FFR resource
• Reserve headroom on GFM resource
• Increase number of inverter units to increase IBR short circuit capacity, overcurrent capacity
• Retrofit a GFL resource to enable GFM function (currently only for the resources with BESS, future could be for standalone PV and wind)
• Retrofit DER inverter ride-through settings
• Revise Rule 14H source requirements document
• Add additional communication and control to increase capacity of controllable DER
• Add GFM STATCOM to address system stability issue
• Add dual-pilot communication to enable fast protection
• Increase circuit breaker size to host more firm generation
• Use dynamic UFLS to improve UFLS effectiveness
• Use advanced protection to address high inverter penetration system protection issue
• Add power quality filter to mitigate power quality issue
• Add individual equipment (e.g., BESS) to provide damping for system oscillation

Pursue procurement(s) as part of the IGP solution sourcing process to determine market for long lead renewable resources such as offshore wind and renewable energy zones to increase resource diversity and mitigate land use risks.

The various futures are consistent in maximizing grid-scale hybrid solar due to its cost-effective energy; however, there are many uncertainties concerning the amount of hybrid solar that will be built over the near-term including, community needs, land availability, slope of the land and willingness of landowners to participate, among others. If high amounts of solar cannot be built in the near-term, other low-carbon resources will be needed. The land constrained scenario suggests that resources that take more than 5 years to develop such as offshore wind will be critical to achieving decarbonization goals. A more diverse portfolio will also improve the resilience of the resource portfolio.

9 APPENDIX

9.1 Capacity Expansion Plans

Figure 125. Resource plans for the High Load and Low Load cases

Year	RESOLVE High Load	RESOLVE Low Load
Stage 1 and 2 Projects	Hoohana Solar 1 Mililani Solar 1 Waiawa Solar AES West O'ahu Solar Barbers Point Solar Kupono Solar Mahi Solar Mountain View Solar Waiawa Phase 2 Solar Kapolei Energy Storage	Hoohana Solar 1 Mililani Solar 1 Waiawa Solar AES West O'ahu Solar Barbers Point Solar Kupono Solar Mahi Solar Mountain View Solar Waiawa Phase 2 Solar Kapolei Energy Storage
2027	Install 82MW of Group 1 Onshore Wind Install 82MW of Group 2 Onshore Wind Install 3MW 5 MWh of Standalone BESS Remove 108 MW of Firm Generation	Install 82MW of Group 1 Onshore Wind Install 82MW of Group 2 Onshore Wind Install 286MW 537MWH of Standalone Battery Remove 108 MW Firm Generation
2028	Install 47MW of LM6000_2x1CC_SyncCond Install 17MW 32 MWh of Standalone BESS	Install 20MW 37MWH of Standalone Battery
2029	Install 134MW 134 MWh of Group 1 Paired PV Install 170MW of LM6000_2x1CC_SyncCond Install 32MW of LM6000CT Install 83MW 160 MWh of Standalone BESS Remove 165 MW of Firm Generation	Install 18MW 33MWH of Standalone Battery Remove 165 MW of Firm Generation
2030	Install 295MW 1060 MWh of Group 1 Paired PV Install 1249MW 3212 MWh of Group 2 Paired PV Install 2MW 0 MWh of Standalone BESS	Install 428MW of Group 1 Paired PV 1500 MWh Install 861MW of Group 2 Paired PV 2346 MWh Install 108MW 203MWH of Standalone Battery
2031	Install 0MW 124 MWh of Group 1 Paired PV Install 195MW 718 MWh of Group 2 Paired PV Remove 30 MW Kahuku Wind	Install 71MW of Group 2 Paired PV 263 MWh Remove 30 MW Kahuku Wind
2032	Install 0MW 157 MWh of Group 1 Paired PV Install 54MW 247 MWh of Group 2 Paired PV Install 125MW 335 MWh of Group 3 Paired PV Remove 1 MW Kapolei Sustainable Energy Park	Install 60MW of Group 2 Paired PV 162 MWh Remove 1 MW Kapolei Sustainable Energy Park
2033	Install 0MW 84 MWh of Group 1 Paired PV Install 0MW 66 MWh of Group 2 Paired PV Install 168MW 516 MWh of Group 3 Paired PV Install 0MW 1 MWh of Standalone BESS Remove 169 MW of Firm Generation Remove 5 MW Kalaeloa Solar II	Install 7MW of Group 2 Paired PV 0 MWh Remove 169 MW of Firm Generation Remove 5 MW Kalaeloa Solar II
2034	Install 20MW 135 MWh of Group 2 Paired PV Install 114MW 343 MWh of Group 3 Paired PV Install 33MW of LM6000CT Remove 5 MW Kalaeloa Renewable Energy Park	Install 5MW of Group 2 Paired PV 0 MWh Remove 5 MW Kalaeloa Renewable Energy Park

Year	RESOLVE High Load	RESOLVE Low Load
2035	Install 204MW of Offshore Wind Install 73MW of LM6000CT	Install 10MW of Group 2 Paired PV 0 MWh Install 44MW of Offshore Wind Install 10MW of LM6000CT
2036		
2037	Remove 171 MW of Firm Generation	Remove 171 MW of Firm Generation
2038	Remove 69 MW Kawailoa Wind	Remove 69 MW Kawailoa Wind
2039	Remove 27.6 MW Waianae Solar	Remove 27.6 MW Waianae Solar
2040	Install 2MW 129 MWh of Group 2 Paired PV Install 588MW 1765 MWh of Group 3 Paired PV Install 152MW of Biomass Install 88MW of LM6000CT	Install 398MW of Group 2 Paired PV 1094 MWh Install 111MW of Group 3 Paired PV 259 MWh Install 37MW of Biomass Install 130MW of LM6000CT
2041	Remove 24 MW Na Pua Makani Wind Remove 109.6 MW Clearway Projects	Remove 24 MW Na Pua Makani Wind Remove 109.6 MW Clearway Projects
2042		
2043		
2044	Remove 20 MW of West Loch	Remove 20 MW of West Loch
2045	Install 73MW 0 MWh of Group 2 Paired PV Install 171MW 153 MWh of Group 3 Paired PV Install 192MW of Biomass Install 59MW 111 MWh of Standalone BESS	Install 126MW of Group 2 Paired PV 0 MWh Install 551MW of Group 3 Paired PV 1297 MWh Install 66MW of Biomass
2046	Remove 269 MW of Firm Generation	Remove 269 MW of Firm Generation
2047		
2048		
2049		
2050	Install 89MW of Biomass	Install 53MW of Group 2 Paired PV 190 MWh Install 182MW of Group 3 Paired PV 212 MWh Install 76MW of Biomass Install 223MW of LM6000CT

Figure 126. Resource plans for the Base case and the Land Constrained case

Year	RESOLVE Base	RESOLVE Land Constrained
Stage 1 and 2 Projects	Hoohana Solar 1 Mililani Solar 1 Waiawa Solar AES West O'ahu Solar Barbers Point Solar Kupono Solar Mahi Solar Mountain View Solar Waiawa Phase 2 Solar Kapolei Energy Storage	Hoohana Solar 1 Mililani Solar 1 Waiawa Solar AES West O'ahu Solar Barbers Point Solar Kupono Solar Mahi Solar Mountain View Solar Waiawa Phase 2 Solar Kapolei Energy Storage
2027	Install 82MW of Group 1 Onshore Wind Install 82MW of Group 2 Onshore Wind Install 231MW 434MWH of Standalone Battery Remove 108 MW of Firm Generation	Install 176MW 331 MWh of Standalone BESS Remove 108 MW of Firm Generation
2028	Install 14MW 26MWH of Standalone Battery	Install 14MW 25 MWh of Standalone BESS
2029	Install 35MW of LM6000_2x1CC_SyncCond Install 42MW 79MWH of Standalone Battery Remove 165 MW of Firm Generation	Install 39MW of LM6000_2x1CC_SyncCond Install 43MW 81 MWh of Standalone BESS Remove 165 MW of Firm Generation
2030	Install 428MW of Group 1 Paired PV 1489 MWh Install 1148MW of Group 2 Paired PV 2973 MWh Install 93MW 174MWH of Standalone Battery	Install 270MW 270 MWh of Group 1 Paired PV Install 88MW 162 MWh of Standalone BESS
2031	Install 0MW of Group 1 Paired PV 74 MWh Install 107MW of Group 2 Paired PV 423 MWh Install 8MW 14MWH of Standalone Battery Remove 30 MW Kahuku Wind	Remove 30 MW Kahuku Wind
2032	Install 0MW of Group 1 Paired PV 68 MWh Install 62MW of Group 2 Paired PV 211 MWh Remove 1 MW Kapolei Sustainable Energy Park	Install 4MW 7 MWh of Standalone BESS Remove 1 MW Kapolei Sustainable Energy Park
2033	Install 0MW of Group 1 Paired PV 19 MWh Install 90MW of Group 2 Paired PV 328 MWh Remove 169 MW of Firm Generation Remove 5 MW Kalaeloa Solar II	Install 172MW of LM6000_2x1CC_SyncCond Install 0MW 1 MWh of Standalone BESS Remove 169 MW of Firm Generation Remove 5 MW Kalaeloa Solar II
2034	Install 101MW of Group 2 Paired PV 321 MWh Install 8MW of LM6000_2x1CC_SyncCond Remove 5 MW Kalaeloa Renewable Energy Park	Install 31MW of LM6000_2x1CC_SyncCond Install 18MW 33 MWh of Standalone BESS Remove 5 MW Kalaeloa Renewable Energy Park
2035	Install 78MW of Offshore Wind Install 6MW of LM6000_2x1CC_SyncCond Install 19MW of LM6000CT	Install 400MW of Offshore Wind Install 22MW of LM6000_2x1CC_SyncCond Install 86MW 162 MWh of Standalone BESS

Year	RESOLVE Base	RESOLVE Land Constrained
2036		
2037	Remove 171 MW of Firm Generation	Remove 171 MW of firm generation
2038	Remove 69 MW Kawailoa Wind	Remove 69 MW Kawailoa Wind
2039	Remove 27.6 MW Waianae Solar	Remove 27.6 MW Waianae Solar
2040	Install 58MW of Group 2 Paired PV 317 MWh Install 628MW of Group 3 Paired PV 1573 MWh Install 6MW of Biomass Install 177MW of LM6000CT	Install 68MW of Aggregated DER 136 MWh Install 154MW of LM6000_2x1CC_SyncCond Install 90MW of LM6000CT Install 23MW 45 MWh of Standalone BESS
2041	Remove 24 MW Na Pua Makani Wind Remove 109.6 MW Clearway Projects	Remove 24 MW Na Pua Makani Wind Remove 109.6 MW Clearway Projects
2042		
2043		
2044	Remove 20 MW of West Loch	Remove 20 MW of West Loch
2045	Install 26MW of Group 2 Paired PV 0 MWh Install 538MW of Group 3 Paired PV 1291 MWh Install 115MW of Biomass Install 7MW 13MWH of Standalone Battery	Install 0MW 933 MWh of Group 1 Paired PV Install 1706MW of Aggregated DER 3412 MWh Install 388MW 2695 MWh of Standalone BESS
2046	Remove 269 MW Firm Generation	Remove 269 MW Firm Generation
2047		
2048		
2049		
2050	Install 0MW of Group 3 Paired PV 223 MWh Install 132MW of Biomass Install 192MW of LM6000CT Install 23MW 51MWH of Standalone Battery	Install 0MW 76 MWh of Group 1 Paired PV Install 961MW of Aggregated DER 1923 MWh Install 185MW of LM6000CT Install 78MW 761 MWh of Standalone BESS

Figure 127. Resource plans for the Base_508, Base_607 and Base_688 scenarios

Year	Base_508	Base_607	Base_688
Stage 1 and 2 Projects	Hoohana Solar 1 Mililani Solar 1 Waiawa Solar AES West O'ahu Solar Barbers Point Solar Kupono Solar ~~Mahi Solar~~ Mountain View Solar Waiawa Phase 2 Solar Kapolei Energy Storage	Hoohana Solar 1 Mililani Solar 1 Waiawa Solar AES West O'ahu Solar Barbers Point Solar Kupono Solar ~~Mahi Solar~~ Mountain View Solar Waiawa Phase 2 Solar Kapolei Energy Storage	Hoohana Solar 1 Mililani Solar 1 Waiawa Solar AES West O'ahu Solar Barbers Point Solar Kupono Solar ~~Mahi Solar~~ Mountain View Solar Waiawa Phase 2 Solar Kapolei Energy Storage
2027	Install 82MW of Group 1 Onshore Wind Install 82MW of Group 2 Onshore Wind Install 231MW 434MWH of Standalone Battery Remove 108 MW Firm Generation	Install 82MW of Group 1 Onshore Wind Install 82MW of Group 2 Onshore Wind Install 231MW 434MWH of Standalone Battery Remove 108 MW Firm Generation	Install 82MW of Group 1 Onshore Wind Install 82MW of Group 2 Onshore Wind Install 231MW 434MWH of Standalone Battery Remove 108 MW Firm Generation
2028	Install 14MW 26MWH of Standalone Battery	Install 14MW 26MWH of Standalone Battery	Install 14MW 26MWH of Standalone Battery
2029	Install 42MW 79MWH of Standalone Battery Install 300 MW CT Install 208 MW CC Remove 165 MW Firm Generation Remove 208 MW KPLP	Install 42MW 79MWH of Standalone Battery Install 300 MW CT Install 208 MW CC Install 99 MW ICE Remove 165 MW Firm Generation Remove 208 MW KPLP	Install 42MW 79MWH of Standalone Battery Install 300 MW CT Install 208 MW CC Install 180 MW Biomass Remove 165 MW Firm Generation Remove 208 MW KPLP
2030	Install 428MW of Group 1 Paired PV 1489 MWh Install 1148MW of Group 2 Paired PV 2973 MWh Install 93MW 174MWH of Standalone Battery	Install 428MW of Group 1 Paired PV 1489 MWh Install 1148MW of Group 2 Paired PV 2973 MWh Install 93MW 174MWH of Standalone Battery	Install 428MW of Group 1 Paired PV 1489 MWh Install 1148MW of Group 2 Paired PV 2973 MWh Install 93MW 174MWH of Standalone Battery
2031	Install 0MW of Group 1 Paired PV 74 MWh Install 107MW of Group 2 Paired PV 423 MWh Install 8MW 14MWH of Standalone Battery Remove 30 MW Kahuku Wind	Install 0MW of Group 1 Paired PV 74 MWh Install 107MW of Group 2 Paired PV 423 MWh Install 8MW 14MWH of Standalone Battery Remove 30 MW Kahuku Wind	Install 0MW of Group 1 Paired PV 74 MWh Install 107MW of Group 2 Paired PV 423 MWh Install 8MW 14MWH of Standalone Battery Remove 30 MW Kahuku Wind
2032	Install 0MW of Group 1 Paired PV 68 MWh Install 62MW of Group 2 Paired PV 211 MWh Remove 1 MW Kapolei Sustainable Energy Park	Install 0MW of Group 1 Paired PV 68 MWh Install 62MW of Group 2 Paired PV 211 MWh Remove 1 MW Kapolei Sustainable Energy Park	Install 0MW of Group 1 Paired PV 68 MWh Install 62MW of Group 2 Paired PV 211 MWh Remove 1 MW Kapolei Sustainable Energy Park

Year	Base_508	Base_607	Base_688
2033	Install 0MW of Group 1 Paired PV 19 MWh Install 90MW of Group 2 Paired PV 328 MWh Remove 169 MW of Firm Generation Remove 5 MW Kalaeloa Solar II	Install 0MW of Group 1 Paired PV 19 MWh Install 90MW of Group 2 Paired PV 328 MWh Remove 169 MW of Firm Generation Remove 5 MW Kalaeloa Solar II	Install 0MW of Group 1 Paired PV 19 MWh Install 90MW of Group 2 Paired PV 328 MWh Remove 169 MW of Firm Generation Remove 5 MW Kalaeloa Solar II
2034	Install 101MW of Group 2 Paired PV 321 MWh Remove 5 MW Kalaeloa Renewable Energy Park	Install 101MW of Group 2 Paired PV 321 MWh Remove 5 MW Kalaeloa Renewable Energy Park	Install 101MW of Group 2 Paired PV 321 MWh Remove 5 MW Kalaeloa Renewable Energy Park
2035	Install 78MW of Offshore Wind	Install 78MW of Offshore Wind	Install 78MW of Offshore Wind
2036			
2037	Remove 171 MW of Firm Generation	Remove 171 MW of Firm Generation	Remove 171 MW of Firm Generation
2038	Remove 69 MW Kawailoa Wind	Remove 69 MW Kawailoa Wind	Remove 69 MW Kawailoa Wind
2039	Remove 27.6 MW Waianae Solar	Remove 27.6 MW Waianae Solar	Remove 27.6 MW Waianae Solar
2040	Install 58MW of Group 2 Paired PV 317 MWh Install 628MW of Group 3 Paired PV 1573 MWh	Install 58MW of Group 2 Paired PV 317 MWh Install 628MW of Group 3 Paired PV 1573 MWh	Install 58MW of Group 2 Paired PV 317 MWh Install 628MW of Group 3 Paired PV 1573 MWh
2041	Remove 24 MW Na Pua Makani Wind Remove 109.6 MW Clearway Projects	Remove 24 MW Na Pua Makani Wind Remove 109.6 MW Clearway Projects	Remove 24 MW Na Pua Makani Wind Remove 109.6 MW Clearway Projects
2042			
2043			
2044	Remove 20 MW of West Loch	Remove 20 MW of West Loch	Remove 20 MW of West Loch
2045	Install 26MW of Group 2 Paired PV 0 MWh Install 538MW of Group 3 Paired PV 1291 MWh Install 7MW 13MWH of Standalone Battery	Install 26MW of Group 2 Paired PV 0 MWh Install 538MW of Group 3 Paired PV 1291 MWh Install 7MW 13MWH of Standalone Battery	Install 26MW of Group 2 Paired PV 0 MWh Install 538MW of Group 3 Paired PV 1291 MWh Install 7MW 13MWH of Standalone Battery
2046	Remove 269 MW Firm Generation	Remove 269 MW Firm Generation	Remove 269 MW Firm Generation
2047			
2048			
2049			
2050	Install 0MW of Group 3 Paired PV 223 MWH Install 23MW 51MWH of Standalone Battery	Install 0MW of Group 3 Paired PV 223 MWH Install 23MW 51MWH of Standalone Battery	Install 0MW of Group 3 Paired PV 223 MWH Install 23MW 51MWH of Standalone Battery

Figure 128. Resource plans for the LC_508, LC_607 and LC_688 scenarios

Year	LC_508	LC_607	LC_688
Stage 1 and 2 Projects	Hoohana Solar 1 Mililani Solar 1 Waiawa Solar AES West O'ahu Solar Barbers Point Solar Kupono Solar ~~Mahi Solar~~ Mountain View Solar Waiawa Phase 2 Solar Kapolei Energy Storage	Hoohana Solar 1 Mililani Solar 1 Waiawa Solar AES West O'ahu Solar Barbers Point Solar Kupono Solar ~~Mahi Solar~~ Mountain View Solar Waiawa Phase 2 Solar Kapolei Energy Storage	Hoohana Solar 1 Mililani Solar 1 Waiawa Solar AES West O'ahu Solar Barbers Point Solar Kupono Solar ~~Mahi Solar~~ Mountain View Solar Waiawa Phase 2 Solar Kapolei Energy Storage
2027	Install 176MW 331 MWh of Standalone BESS Remove 108 MW of Firm Generation	Install 176MW 331 MWh of Standalone BESS Remove 108 MW of Firm Generation	Install 176MW 331 MWh of Standalone BESS Remove 108 MW of Firm Generation
2028	Install 14MW 25 MWh of Standalone BESS	Install 14MW 25 MWh of Standalone BESS	Install 14MW 25 MWh of Standalone BESS
2029	Install 43MW 81 MWh of Standalone BESS Install 300 MW CT Install 208 MW CC Remove 165 MW of Firm Generation Remove 208 MW KPLP	Install 43MW 81 MWh of Standalone BESS Install 300 MW CT Install 208 MW CC Install 99 MW ICE Remove 165 MW of Firm Generation Remove 208 MW KPLP	Install 43MW 81 MWh of Standalone BESS Install 300 MW CT Install 208 MW CC Install 180 MW Biomass Remove 165 MW of Firm Generation Remove 208 MW KPLP
2030	Install 270MW 270 MWh of Group 1 Paired PV Install 88MW 162 MWh of Standalone BESS **Install 120 MW 480 MWh of Mahi Solar** **Install 60 MW 240 MWh of Kupehau**	Install 270MW 270 MWh of Group 1 Paired PV Install 88MW 162 MWh of Standalone BESS **Install 120 MW 480 MWh of Mahi Solar** **Install 60 MW 240 MWh of Kupehau**	Install 270MW 270 MWh of Group 1 Paired PV Install 88MW 162 MWh of Standalone BESS **Install 120 MW 480 MWh of Mahi Solar** **Install 60 MW 240 MWh of Kupehau**
2031	Remove 30 MW Kahuku Wind	Remove 30 MW Kahuku Wind	Remove 30 MW Kahuku Wind
2032	Install 4MW 7 MWh of Standalone BESS Remove 1 MW Kapolei Sustainable Energy Park	Install 4MW 7 MWh of Standalone BESS Remove 1 MW Kapolei Sustainable Energy Park	Install 4MW 7 MWh of Standalone BESS Remove 1 MW Kapolei Sustainable Energy Park
2033	Install 0MW 1 MWh of Standalone BESS Remove 169 MW of Firm Generation Remove 5 MW Kalaeloa Solar II	Install 0MW 1 MWh of Standalone BESS Remove 169 MW of Firm Generation Remove 5 MW Kalaeloa Solar II	Install 0MW 1 MWh of Standalone BESS Remove 169 MW of Firm Generation Remove 5 MW Kalaeloa Solar II
2034	Install 18MW 33 MWh of Standalone BESS Remove 5 MW Kalaeloa Renewable Energy Park	Install 18MW 33 MWh of Standalone BESS Remove 5 MW Kalaeloa Renewable Energy Park	Install 18MW 33 MWh of Standalone BESS Remove 5 MW Kalaeloa Renewable Energy Park

Year	LC_508	LC_607	LC_688
2035	Install 400MW of Offshore Wind Install 86MW 162 MWh of Standalone BESS	Install 400MW of Offshore Wind Install 86MW 162 MWh of Standalone BESS	Install 400MW of Offshore Wind Install 86MW 162 MWh of Standalone BESS
2036			
2037	Remove 171 MW of Firm Generation	Remove 171 MW of Firm Generation	Remove 171 MW of Firm Generation
2038	Remove 69 MW Kawailoa Wind	Remove 69 MW Kawailoa Wind	Remove 69 MW Kawailoa Wind
2039	Remove 27.6 MW Waianae Solar	Remove 27.6 MW Waianae Solar	Remove 27.6 MW Waianae Solar
2040	Install 68MW of Aggregated DER 136 MWh Install 23MW 45 MWh of Standalone BESS	Install 68MW of Aggregated DER 136 MWh Install 23MW 45 MWh of Standalone BESS	Install 68MW of Aggregated DER 136 MWh Install 23MW 45 MWh of Standalone BESS
2041	Remove 24 MW Na Pua Makani Wind Remove 109.6 MW Clearway Projects	Remove 24 MW Na Pua Makani Wind Remove 109.6 MW Clearway Projects	Remove 24 MW Na Pua Makani Wind Remove 109.6 MW Clearway Projects
2042			
2043			
2044	Remove 20 MW of West Loch	Remove 20 MW of West Loch	Remove 20 MW of West Loch
2045	Install 0MW 933 MWh of Group 1 Paired PV Install 1706MW of Aggregated DER 3412 MWh Install 388MW 2695 MWh of Standalone BESS	Install 0MW 933 MWh of Group 1 Paired PV Install 1706MW of Aggregated DER 3412 MWh Install 388MW 2695 MWh of Standalone BESS	Install 0MW 933 MWh of Group 1 Paired PV Install 1706MW of Aggregated DER 3412 MWh Install 388MW 2695 MWh of Standalone BESS
2046	Remove 269 MW of Firm Generation	Remove 269 MW of Firm Generation	Remove 269 MW of Firm Generation
2047			
2048			
2049			
2050	Install 0MW 76 MWh of Group 1 Paired PV Install 961MW of Aggregated DER 1923 MWh Install 78MW 761 MWh of Standalone BESS	Install 0MW 76 MWh of Group 1 Paired PV Install 961MW of Aggregated DER 1923 MWh Install 78MW 761 MWh of Standalone BESS	Install 0MW 76 MWh of Group 1 Paired PV Install 961MW of Aggregated DER 1923 MWh Install 78MW 761 MWh of Standalone BESS

Figure 129. Resource plans for the Base_508_Staggered, Base_607_Staggered and Base_688_Staggered scenarios

Year	Base_508 Staggered	Base_607 Staggered	Base_688 Staggered
Stage 1 and 2 Projects	Hoohana Solar 1 Mililani Solar 1 Waiawa Solar AES West O'ahu Solar Barbers Point Solar Kupono Solar ~~Mahi Solar~~ Mountain View Solar Waiawa Phase 2 Solar Kapolei Energy Storage	Hoohana Solar 1 Mililani Solar 1 Waiawa Solar AES West O'ahu Solar Barbers Point Solar Kupono Solar ~~Mahi Solar~~ Mountain View Solar Waiawa Phase 2 Solar Kapolei Energy Storage	Hoohana Solar 1 Mililani Solar 1 Waiawa Solar AES West O'ahu Solar Barbers Point Solar Kupono Solar ~~Mahi Solar~~ Mountain View Solar Waiawa Phase 2 Solar Kapolei Energy Storage
2027	Install 82MW of Group 1 Onshore Wind Install 82MW of Group 2 Onshore Wind Install 231MW 434MWH of Standalone Battery Remove 108 MW Firm Generation	Install 82MW of Group 1 Onshore Wind Install 82MW of Group 2 Onshore Wind Install 231MW 434MWH of Standalone Battery Remove 108 MW Firm Generation	Install 82MW of Group 1 Onshore Wind Install 82MW of Group 2 Onshore Wind Install 231MW 434MWH of Standalone Battery Remove 108 MW Firm Generation
2028	Install 14MW 26MWH of Standalone Battery	Install 14MW 26MWH of Standalone Battery	Install 14MW 26MWH of Standalone Battery
2029	Install 42MW 79MWH of Standalone Battery Install 300 MW CT Remove 165 MW Firm Generation Remove 208 MW KPLP	Install 42MW 79MWH of Standalone Battery Install 300 MW CT Install 99 MW ICE Remove 165 MW Firm Generation Remove 208 MW KPLP	Install 42MW 79MWH of Standalone Battery Install 300 MW CT Install 180 MW Biomass Remove 165 MW Firm Generation Remove 208 MW KPLP
2030	Install 428MW of Group 1 Paired PV 1489 MWh Install 1148MW of Group 2 Paired PV 2973 MWh Install 93MW 174MWH of Standalone Battery	Install 428MW of Group 1 Paired PV 1489 MWh Install 1148MW of Group 2 Paired PV 2973 MWh Install 93MW 174MWH of Standalone Battery	Install 428MW of Group 1 Paired PV 1489 MWh Install 1148MW of Group 2 Paired PV 2973 MWh Install 93MW 174MWH of Standalone Battery
2031	Install 0MW of Group 1 Paired PV 74 MWh Install 107MW of Group 2 Paired PV 423 MWh Install 8MW 14MWH of Standalone Battery Remove 30 MW Kahuku Wind	Install 0MW of Group 1 Paired PV 74 MWh Install 107MW of Group 2 Paired PV 423 MWh Install 8MW 14MWH of Standalone Battery Remove 30 MW Kahuku Wind	Install 0MW of Group 1 Paired PV 74 MWh Install 107MW of Group 2 Paired PV 423 MWh Install 8MW 14MWH of Standalone Battery Remove 30 MW Kahuku Wind
2032	Install 0MW of Group 1 Paired PV 68 MWh Install 62MW of Group 2 Paired PV 211 MWh Remove 1 MW Kapolei Sustainable Energy Park	Install 0MW of Group 1 Paired PV 68 MWh Install 62MW of Group 2 Paired PV 211 MWh Remove 1 MW Kapolei Sustainable Energy Park	Install 0MW of Group 1 Paired PV 68 MWh Install 62MW of Group 2 Paired PV 211 MWh Remove 1 MW Kapolei Sustainable Energy Park

Year	Base_508 Staggered	Base_607 Staggered	Base_688 Staggered
2033	Install 0MW of Group 1 Paired PV 19 MWh Install 90MW of Group 2 Paired PV 328 MWh Install 208 MW CC Remove 169 MW of Firm Generation Remove 5 MW Kalaeloa Solar II	Install 0MW of Group 1 Paired PV 19 MWh Install 90MW of Group 2 Paired PV 328 MWh Install 208 MW CC Remove 169 MW of Firm Generation Remove 5 MW Kalaeloa Solar II	Install 0MW of Group 1 Paired PV 19 MWh Install 90MW of Group 2 Paired PV 328 MWh Install 208 MW CC Remove 169 MW of Firm Generation Remove 5 MW Kalaeloa Solar II
2034	Install 101MW of Group 2 Paired PV 321 MWh Remove 5 MW Kalaeloa Renewable Energy Park	Install 101MW of Group 2 Paired PV 321 MWh Remove 5 MW Kalaeloa Renewable Energy Park	Install 101MW of Group 2 Paired PV 321 MWh Remove 5 MW Kalaeloa Renewable Energy Park
2035	Install 78MW of Offshore Wind	Install 78MW of Offshore Wind	Install 78MW of Offshore Wind
2036			
2037	Remove 171 MW of Firm Generation	Remove 171 MW of Firm Generation	Remove 171 MW of Firm Generation
2038	Remove 69 MW Kawailoa Wind	Remove 69 MW Kawailoa Wind	Remove 69 MW Kawailoa Wind
2039	Remove 27.6 MW Waianae Solar	Remove 27.6 MW Waianae Solar	Remove 27.6 MW Waianae Solar
2040	Install 58MW of Group 2 Paired PV 317 MWh Install 628MW of Group 3 Paired PV 1573 MWh	Install 58MW of Group 2 Paired PV 317 MWh Install 628MW of Group 3 Paired PV 1573 MWh	Install 58MW of Group 2 Paired PV 317 MWh Install 628MW of Group 3 Paired PV 1573 MWh
2041	Remove 24 MW Na Pua Makani Wind Remove 109.6 MW Clearway Projects	Remove 24 MW Na Pua Makani Wind Remove 109.6 MW Clearway Projects	Remove 24 MW Na Pua Makani Wind Remove 109.6 MW Clearway Projects
2042			
2043			
2044	Remove 20 MW of West Loch	Remove 20 MW of West Loch	Remove 20 MW of West Loch
2045	Install 26MW of Group 2 Paired PV 0 MWh Install 538MW of Group 3 Paired PV 1291 MWh Install 7MW 13MWH of Standalone Battery	Install 26MW of Group 2 Paired PV 0 MWh Install 538MW of Group 3 Paired PV 1291 MWh Install 7MW 13MWH of Standalone Battery	Install 26MW of Group 2 Paired PV 0 MWh Install 538MW of Group 3 Paired PV 1291 MWh Install 7MW 13MWH of Standalone Battery
2046	Remove 269 MW Firm Generation	Remove 269 MW Firm Generation	Remove 269 MW Firm Generation
2047			
2048			
2049			
2050	Install 0MW of Group 3 Paired PV 223 MWH Install 23MW 51MWH of Standalone Battery	Install 0MW of Group 3 Paired PV 223 MWH Install 23MW 51MWH of Standalone Battery	Install 0MW of Group 3 Paired PV 223 MWH Install 23MW 51MWH of Standalone Battery

Figure 130. Resource plans for the LC_508_Staggered, LC_607_Staggered and LC_688_Staggered scenarios

Year	LC_508 Staggered	LC_607 Staggered	LC_688 Staggered
Stage 1 and 2 Projects	Hoohana Solar 1 Mililani Solar 1 Waiawa Solar AES West O'ahu Solar Barbers Point Solar Kupono Solar ~~Mahi Solar~~ Mountain View Solar Waiawa Phase 2 Solar Kapolei Energy Storage	Hoohana Solar 1 Mililani Solar 1 Waiawa Solar AES West O'ahu Solar Barbers Point Solar Kupono Solar ~~Mahi Solar~~ Mountain View Solar Waiawa Phase 2 Solar Kapolei Energy Storage	Hoohana Solar 1 Mililani Solar 1 Waiawa Solar AES West O'ahu Solar Barbers Point Solar Kupono Solar ~~Mahi Solar~~ Mountain View Solar Waiawa Phase 2 Solar Kapolei Energy Storage
2027	Install 176MW 331 MWh of Standalone BESS Remove 108 MW of Firm Generation	Install 176MW 331 MWh of Standalone BESS Remove 108 MW of Firm Generation	Install 176MW 331 MWh of Standalone BESS Remove 108 MW of Firm Generation
2028	Install 14MW 25 MWh of Standalone BESS	Install 14MW 25 MWh of Standalone BESS	Install 14MW 25 MWh of Standalone BESS
2029	Install 43MW 81 MWh of Standalone BESS Install 300 MW CT Remove 165 MW of Firm Generation Remove 208 MW KPLP	Install 43MW 81 MWh of Standalone BESS Install 300 MW CT Install 99 MW ICE Remove 165 MW of Firm Generation Remove 208 MW KPLP	Install 43MW 81 MWh of Standalone BESS Install 300 MW CT Install 180 MW Biomass Remove 165 MW of Firm Generation Remove 208 MW KPLP
2030	Install 270MW 270 MWh of Group 1 Paired PV Install 88MW 162 MWh of Standalone BESS **Install 120 MW 480 MWh of Mahi Solar** **Install 60 MW 240 MWh of Kupehau**	Install 270MW 270 MWh of Group 1 Paired PV Install 88MW 162 MWh of Standalone BESS **Install 120 MW 480 MWh of Mahi Solar** **Install 60 MW 240 MWh of Kupehau**	Install 270MW 270 MWh of Group 1 Paired PV Install 88MW 162 MWh of Standalone BESS **Install 120 MW 480 MWh of Mahi Solar** **Install 60 MW 240 MWh of Kupehau**
2031	Remove 30 MW Kahuku Wind	Remove 30 MW Kahuku Wind	Remove 30 MW Kahuku Wind
2032	Install 4MW 7 MWh of Standalone BESS Remove 1 MW Kapolei Sustainable Energy Park	Install 4MW 7 MWh of Standalone BESS Remove 1 MW Kapolei Sustainable Energy Park	Install 4MW 7 MWh of Standalone BESS Remove 1 MW Kapolei Sustainable Energy Park
2033	Install 0MW 1 MWh of Standalone BESS Install 208 MW CC Remove 169 MW of Firm Generation Remove 5 MW Kalaeloa Solar II	Install 0MW 1 MWh of Standalone BESS Install 208 MW CC Remove 169 MW of Firm Generation Remove 5 MW Kalaeloa Solar II	Install 0MW 1 MWh of Standalone BESS Install 208 MW CC Remove 169 MW of Firm Generation Remove 5 MW Kalaeloa Solar II

Year	LC_508 Staggered	LC_607 Staggered	LC_688 Staggered
2034	Install 18MW 33 MWh of Standalone BESS Remove 5 MW Kalaeloa Renewable Energy Park	Install 18MW 33 MWh of Standalone BESS Remove 5 MW Kalaeloa Renewable Energy Park	Install 18MW 33 MWh of Standalone BESS Remove 5 MW Kalaeloa Renewable Energy Park
2035	Install 400MW of Offshore Wind Install 86MW 162 MWh of Standalone BESS	Install 400MW of Offshore Wind Install 86MW 162 MWh of Standalone BESS	Install 400MW of Offshore Wind Install 86MW 162 MWh of Standalone BESS
2036			
2037	Remove 171 MW of Firm Generation	Remove 171 MW of Firm Generation	Remove 171 MW of Firm Generation
2038	Remove 69 MW Kawailoa Wind	Remove 69 MW Kawailoa Wind	Remove 69 MW Kawailoa Wind
2039	Remove 27.6 MW Waianae Solar	Remove 27.6 MW Waianae Solar	Remove 27.6 MW Waianae Solar
2040	Install 68MW of Aggregated DER 136 MWh Install 23MW 45 MWh of Standalone BESS	Install 68MW of Aggregated DER 136 MWh Install 23MW 45 MWh of Standalone BESS	Install 68MW of Aggregated DER 136 MWh Install 23MW 45 MWh of Standalone BESS
2041	Remove 24 MW Na Pua Makani Wind Remove 109.6 MW Clearway Projects	Remove 24 MW Na Pua Makani Wind Remove 109.6 MW Clearway Projects	Remove 24 MW Na Pua Makani Wind Remove 109.6 MW Clearway Projects
2042			
2043			
2044	Remove 20 MW of West Loch	Remove 20 MW of West Loch	Remove 20 MW of West Loch
2045	Install 0MW 933 MWh of Group 1 Paired PV Install 1706MW of Aggregated DER 3412 MWh Install 388MW 2695 MWh of Standalone BESS	Install 0MW 933 MWh of Group 1 Paired PV Install 1706MW of Aggregated DER 3412 MWh Install 388MW 2695 MWh of Standalone BESS	Install 0MW 933 MWh of Group 1 Paired PV Install 1706MW of Aggregated DER 3412 MWh Install 388MW 2695 MWh of Standalone BESS
2046	Remove 269 MW of Firm Generation	Remove 269 MW of Firm Generation	Remove 269 MW of Firm Generation
2047			
2048			
2049			
2050	Install 0MW 76 MWh of Group 1 Paired PV Install 961MW of Aggregated DER 1923 MWh Install 78MW 761 MWh of Standalone BESS	Install 0MW 76 MWh of Group 1 Paired PV Install 961MW of Aggregated DER 1923 MWh Install 78MW 761 MWh of Standalone BESS	Install 0MW 76 MWh of Group 1 Paired PV Install 961MW of Aggregated DER 1923 MWh Install 78MW 761 MWh of Standalone BESS

Hawaiʻi Powered

Maui Near Term Grid Needs Assessment

July 2022 Report

Hawaiian Electric

July 29, 2022

Maui Grid Needs Assessment

Executive Summary - Background

On February 18, 2022 the Commission directed Hawaiian Electric to prepare a Stage 3 RFP to address reliability needs:

> As such, in order to meet the future replacement capacity needs, the Commission finds it is necessary for Hawaiian Electric to perform another round of competitive procurements on Oahu and Maui as soon as possible. Accordingly, the Commission directs Hawaiian Electric to develop RFP materials for a Stage 3 competitive bidding process.
>
> The Stage 3 RFP scope should be based on the latest grid needs assessment for Oahu and Maui and should account for the anticipated development schedules for the Stage 1 and 2 projects.
>
> In summary, the Commission directs Hawaiian Electric to move with urgency to ensure an adequate amount of replacement renewable projects are pursued in order to meet the reliability needs and fossil fuel retirement goals in line with Hawaii's energy policy goals.

On March 23, 2022 the Commission provided additional guidance, to conduct a Stage 3 RFP:

> On Maui, notwithstanding the Company's March 10 Letter recommending delaying the Stage 3 RFP, Hawaiian Electric has separately identified "the need to urgently issue an RFP for additional resources to be in place by 2027[,]" due to the Company's concern that 50 MW of capacity at the Maalaea Power Plant may reach end of life in this timeframe. The Commission also notes the heightened need for reducing the reliance on fossil fuels in light of recent geopolitical tensions impacting the price of Hawaii's fuel supply.
>
> The scope of the Stage 3 RFPs can be tailored to meet the near-term needs without precluding future procurements or conflicting with forthcoming results from the IGP docket, as directed by the Commission regarding the Firm Renewable RFP on Oahu. In developing the Stage 3 RFPs, the Commission directs Hawaiian Electric to be explicit in its justification for the scope of this and any parallel procurements.

Executive Summary – Objectives

Objectives of this assessment include:

- Develop resource portfolios that meet near-term RPS and GHG reduction goals and put Maui in an advantageous position to meet longer-term RPS and GHG goals
- Ensure reliability of the system through a balanced portfolio of resources that can be reasonably in-service by 2027 to mitigate the removal of up to 80 MW of firm thermal generation
- Add new low-cost renewable dispatchable generation (wind, solar, battery energy storage) to further decarbonize the electric sector
- Acquire more flexibility for the current and future generation system, building upon the recently acquired renewable dispatchable solar generation and aggregated grid services
- Diversify the type and geography of the resource portfolio to be more resilient
- Inform Stage 3 procurement and Company contingency plans

Executive Summary – Key Findings

- Low-cost renewable energy backed by firm generation continues to be the optimal resource mix over the next decade across different futures of low, base, and high adoption of customer technologies.

- By 2030, 170 GWh of energy efficiency, 56 MW of private rooftop solar, and 43 MW of private battery energy storage is needed to reduce supply-side energy and capacity needs to ensure resource adequacy. All scenarios analyzed include the impacts of 30 MW Battery Bonus/Grid Services Program.

- In addition to the energy provided by the original portfolio of Stage 1 and 2 projects, the optimized resource plan calls for an additional 240 GWh of renewable energy to be acquired by 2027, which includes replacement energy from the expiring 30 MW Kaheawa Wind Power 1 power purchase agreement, and approximately 13 MW of firm generation. The energy provided by projects that withdrew from the recent RFP process would add to the 240 GWh to inform the Stage 3 procurement target.

- Probabilistic resource adequacy analysis indicates that 9 MW of renewable firm generation would minimize occurrences of annual unserved energy if the optimized resource plan indicated above can be interconnected by 2027. By 2035, another 9 MW for a total of 18 MW of renewable firm generation would be needed to accommodate future load growth. When combining Stage 1 and 2 projects plus future resources, a total of 290 MW of PV+BESS and wind and 40 MW of standalone storage must be interconnected by 2027 to meet reliability metrics.

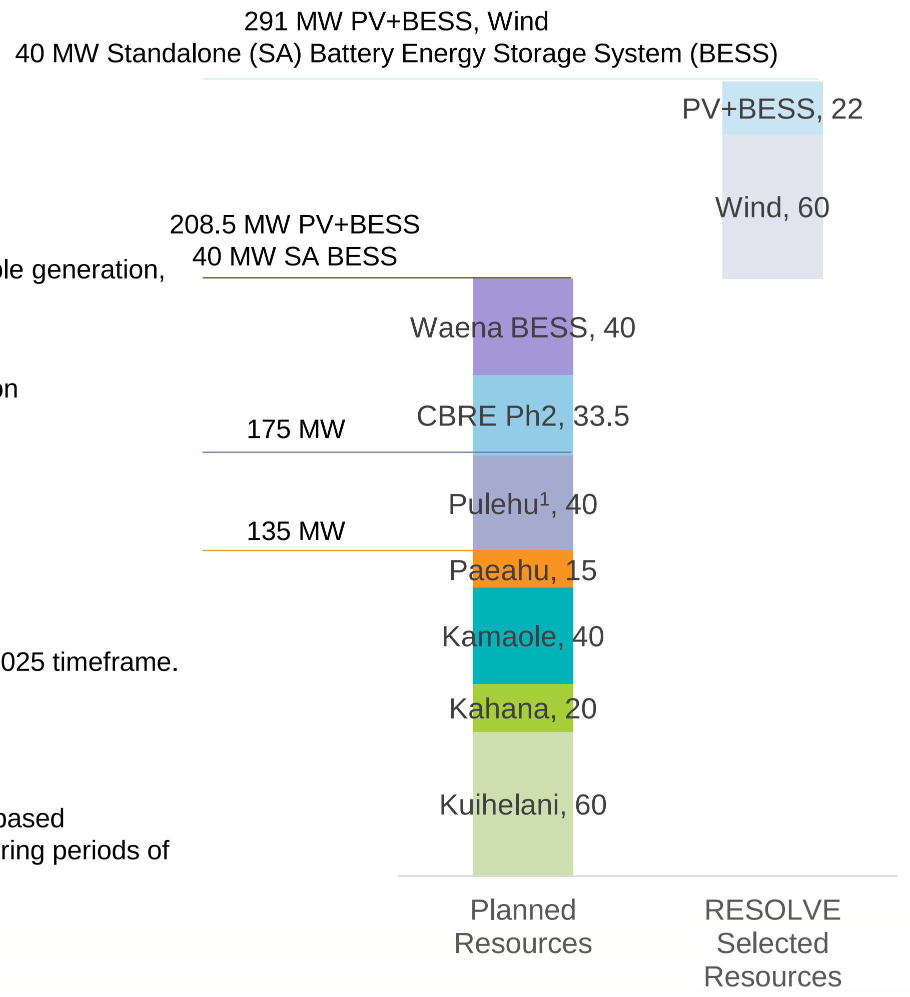
- The Stage 3 procurement targets and contingency plans should consider a number of risks and uncertainties; including but not limited to, on-going supply chain issues, economic and inflationary factors, force majeure, among others. By 2027, Kahului Power Plant (32 MW) must be retired to comply with environmental regulations and 49 MW of firm generation at Maalaea Power Plant are at risk in the 2025-2026 timeframe due to unavailability of spare parts.

- Hawaiian Electric recommends the Stage 3 procurement seek up to 40 MW of firm generation (along with continued efforts for battery bonus and grid services aggregation programs) to mitigate reliability and supply chain risks and uncertainties. In a scenario where 142 MW of renewable resources are interconnected by 2027, the addition of 40 MW of firm generation would not satisfy reliability targets; however, would minimize annual unserved energy and place the expected reliability slightly worse than the 2021 benchmark of 0.15 days/year. In a scenario where 242 MW of renewable resources are interconnected by 2027, 18 MW of firm generation is needed to achieve the same level of reliability as 2021 benchmarks.

Executive Summary – Key Findings

- Reliability Standards Used by Various Jurisdictions
  - Loss of Load Expectation (LOLE) ≤ 0.10 Days/Yr (US Mainland)
  - Loss of Load Hours (LOLH) ≤ 3 hrs (Belgium, France, GB, Poland)
  - Expected Unserved Energy (EUE) ≤ 20 MWh or 0.002% of load (AEMO)
- In 2030, compliance with all three standards is achievable with various resource mixes
  - **RESOLVE Base Case, 18 MW Firm Generation Addition Scenario ($214MM)[2]**: 291 MW of variable generation, 40 MW of standalone BESS, and 18 MW of firm generation
    - Variable Generation: 209 MW planned, 82 MW future (includes 60 MW wind)
  - **Low Renewable Scenario ($248MM)[2]**: 142 MW of variable generation and 63 MW of firm generation
    - Variable Generation: 60 MW planned (Kuihelani), 82 MW future (includes 60 MW wind)
  - **No Firm Addition Scenario ($280MM)[2]**: 328 MW of variable generation
    - Variable Generation: 60 MW planned (Kuihelani), 268 MW future (includes 60 MW wind)
- Assumed Removals from Service
  - Kahului 1-4 (32 MW) – Must be retired in 2027 due to environmental regulations
  - Maalaea 10-13 (49 MW) – Manufacturer will no longer produce spare parts; end of life expected in 2025 timeframe.
  - Maalaea 4-9 (33 MW)
  - Kaheawa Wind Power 1 (30 MW) – Expiring PPA in 2027
- Firm Generation – In this report, firm generation or thermal generation refers to a synchronous machine based technology that is available at any time under system operator dispatch for as long as needed, except during periods of outage and deration, and is not energy limited or weather dependent.

Planned Variable Resource Additions and Future Resources Optimized in RESOLVE



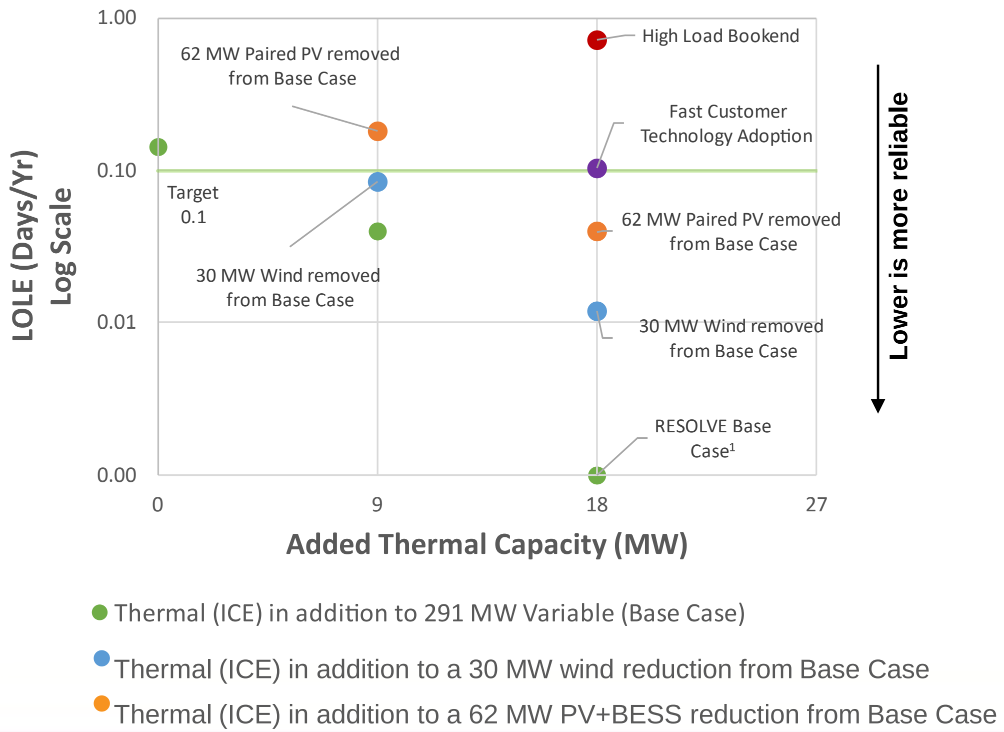
ATTACHMENT 2
PAGE 6 OF 70

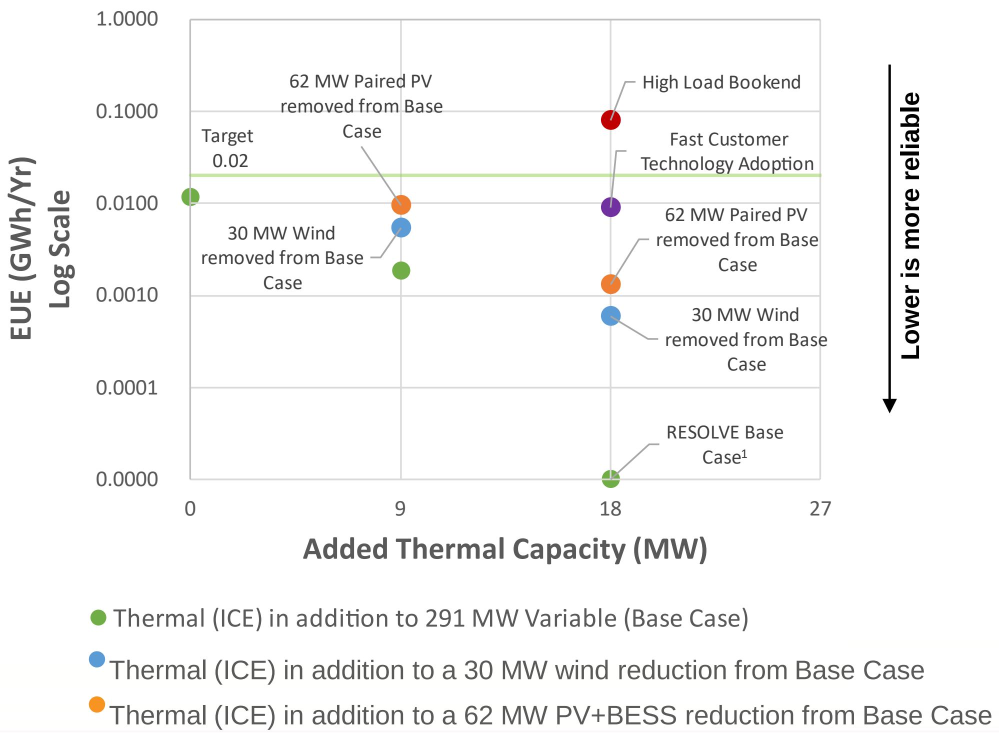
1. Pulehu Solar withdrew from the RFP process on May 4, 2022
2. 1 year revenue requirements for year 2030

Executive Summary – Key Findings: **18 MW of new firm generation provides a reasonable level of reliability over a range of potential future pathways and uncertainties**

Probabilistic Resource Adequacy Analysis of the RESOLVE Base Case Sensitivities: Incremental changes to wind, PV+BESS, firm generation
Planned Resources: 209 MW of PV+BESS from Stage 1 and 2, and 40 MW standalone BESS
Future resources beyond planned: 82 MW of variable generation

Incremental additions of internal combustion engines (ICE) firm (thermal) generation of 9-18 MW meets both LOLE and EUE targets as shown in the green data points. In orange and blue data points are removals of wind or PV+BESS capacities from the base RESOLVE (optimized) case to simulate market conditions where not all projects reach commercial operations.





1. RESOLVE Base case selected 13 MW combined cycle by 2030, in addition to 60 MW onshore wind and 22 MW PV+BESS, which is roughly equivalent to the 18 MW ICE addition evaluated here.

Executive Summary – Key Findings: **New Firm Generation can address EUE shortfalls in low variable renewable periods**

Base Case with 0 MW Firm Generation

Hours Beginning	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	0.00	0.00	0.00	0.40	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1	0.00	0.00	0.00	0.10	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.07	0.22	0.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.25	0.00	0.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.37	0.32	0.35	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.13	0.25	0.27	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.52	0.22	0.68	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.27	0.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	0.00	0.00	0.00	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	0.00	0.00	0.00	0.18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	0.00	0.00	0.16	0.55	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
18	0.00	0.00	0.13	0.61	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
19	0.00	0.00	0.33	0.83	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
20	0.00	0.00	0.02	0.28	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
21	0.00	0.00	0.09	0.43	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
22	0.00	0.00	0.48	1.30	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.28	0.95	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Base Case with 9 MW Firm Generation

Hours Beginning	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.18	0.06	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.12	0.05	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.02	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.27	0.17	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	0.00	0.00	0.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	0.00	0.00	0.03	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
18	0.00	0.00	0.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
20	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
21	0.00	0.00	0.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
22	0.00	0.00	0.01	0.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.25	0.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Pictured are heatmaps of unserved energy to show likelihood of when unserved energy may occur based on probabilistic resource adequacy analysis. Shortfalls are shown during the months of March, April and May where wind has a lower capacity factor and the PV+BESS do not have enough energy to load shift and meet unserved demand.

Executive Summary – Key Findings: **With limited new renewables (Kuihelani Solar, future 82 MW PV+BESS / wind), 63 MW firm generation is needed to improve reliability to established standards for LOLE and EUE**

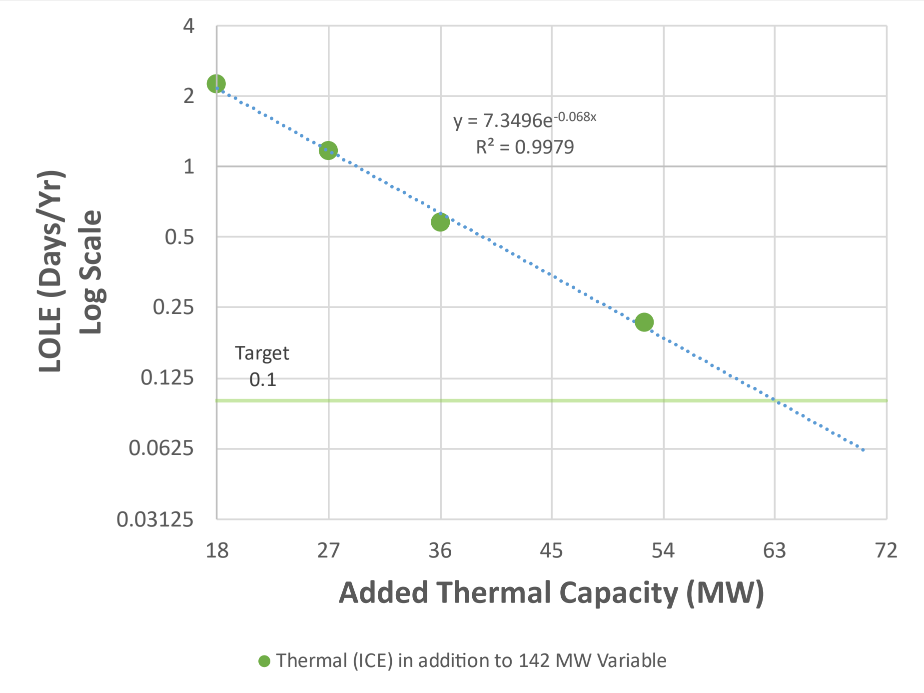
Probabilistic Resource Adequacy Analysis

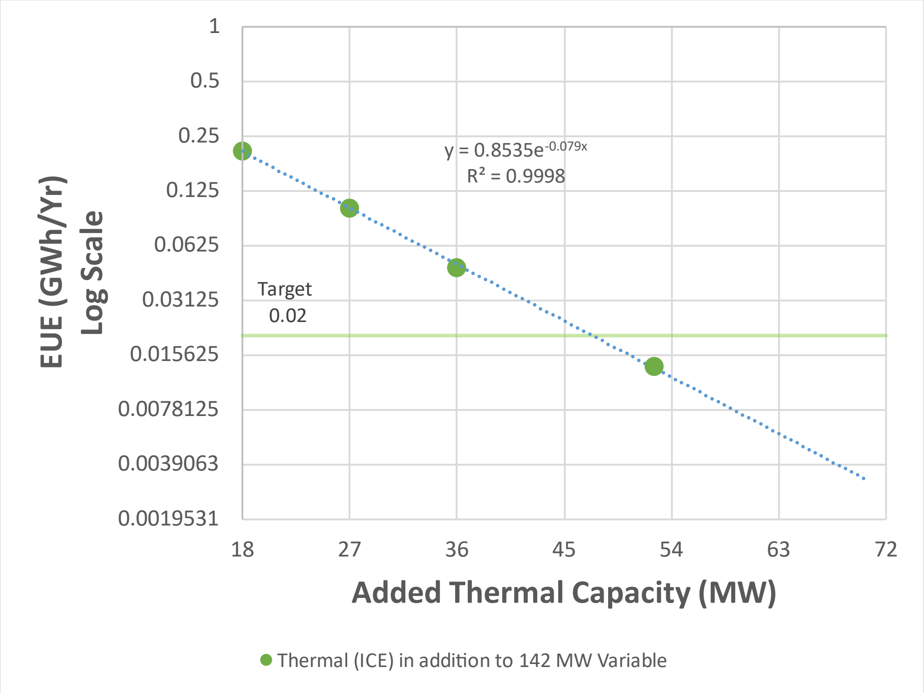
Kuihelani Only with Firm Generation (ICE) Sensitivities: Kuihelani, 60 MW wind, 22 MW PV+BESS, plus 9-18 MW incremental ICE additions

Planned Resources: 60 MW (Kuihelani)

Beyond Planned Resources: 82 MW of variable generation

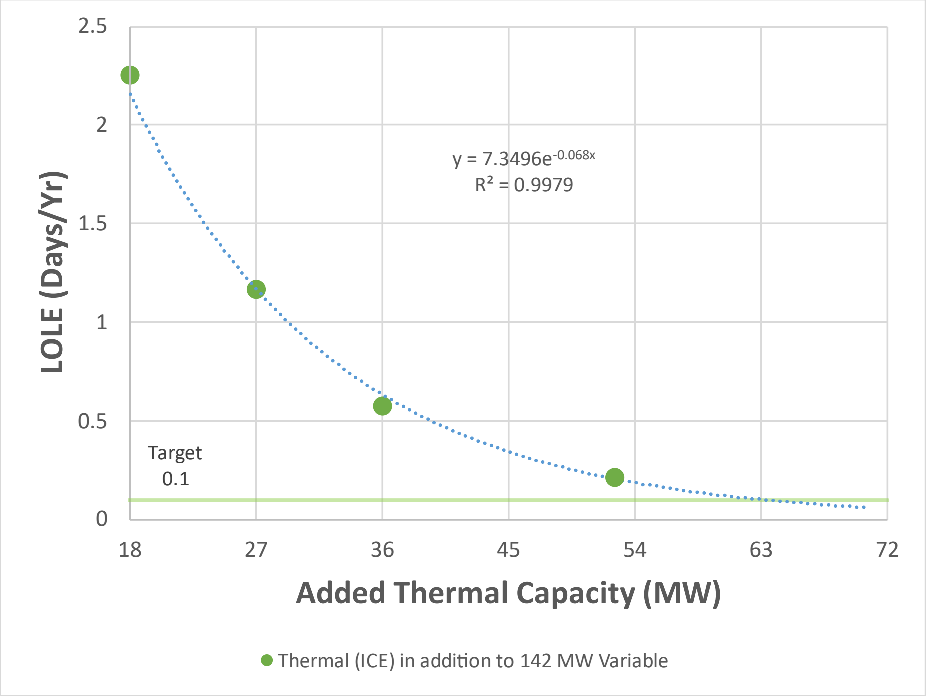
In a case where project delays persist and a total of 142 MW of variable generation reaches commercial operations by 2027, approximately 48 MW of firm generation meets the EUE target but not the LOLE target. Approximately 63 MW of firm generation is needed to meet the LOLE target.

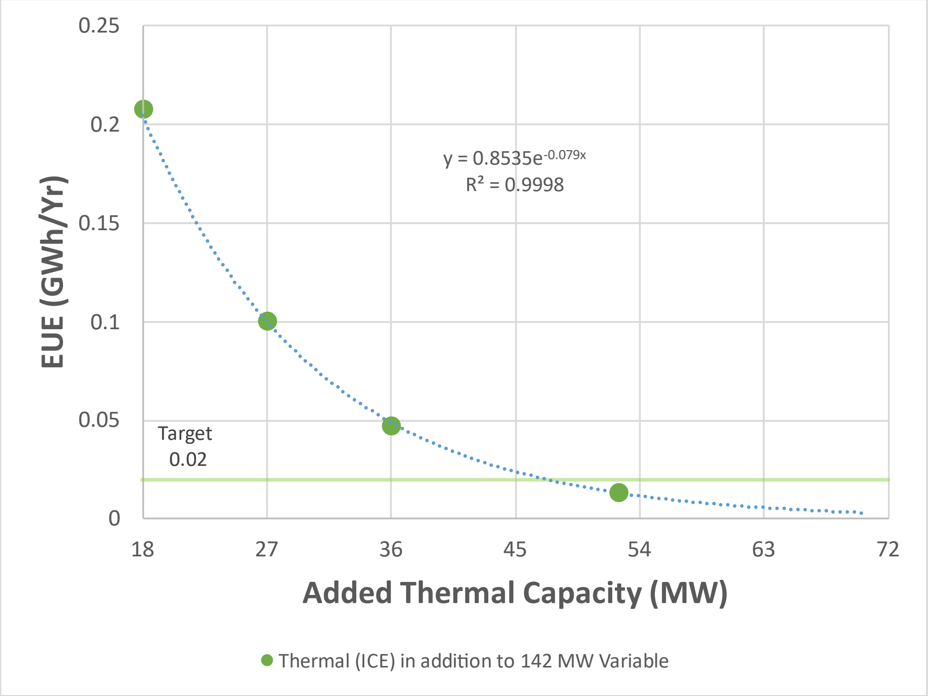




Executive Summary – Key Findings: **Resource portfolio diversity is important to balance diminishing returns on reliability improvements when adding increasing amounts of a single resource type**

Using the same data and analysis from the previous slide, the following figures expressed in non-log scale, show that increasing additions of the same resource type have diminishing returns on improvements to reliability.

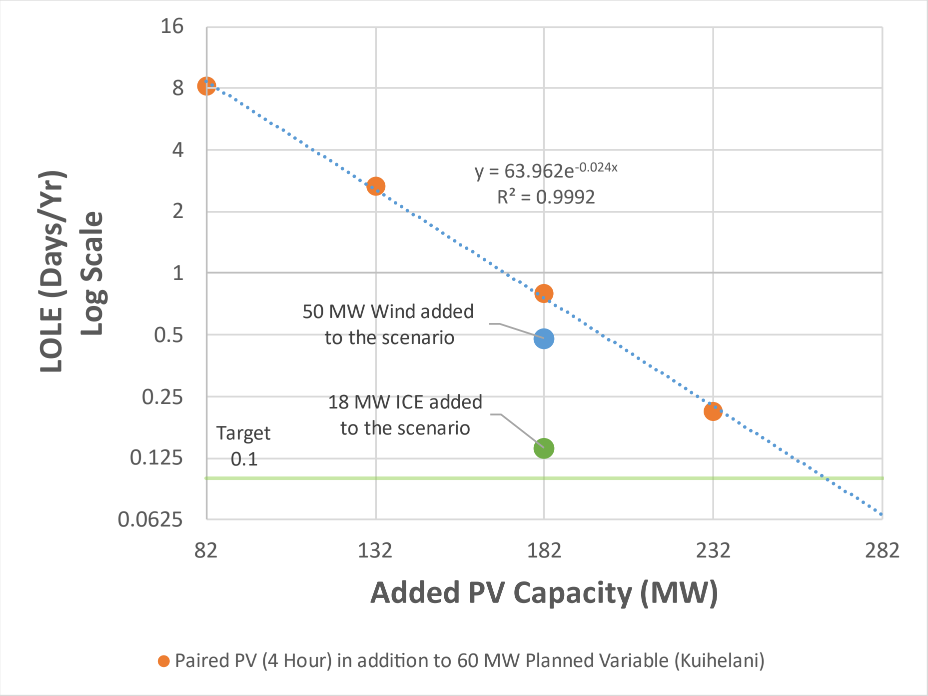


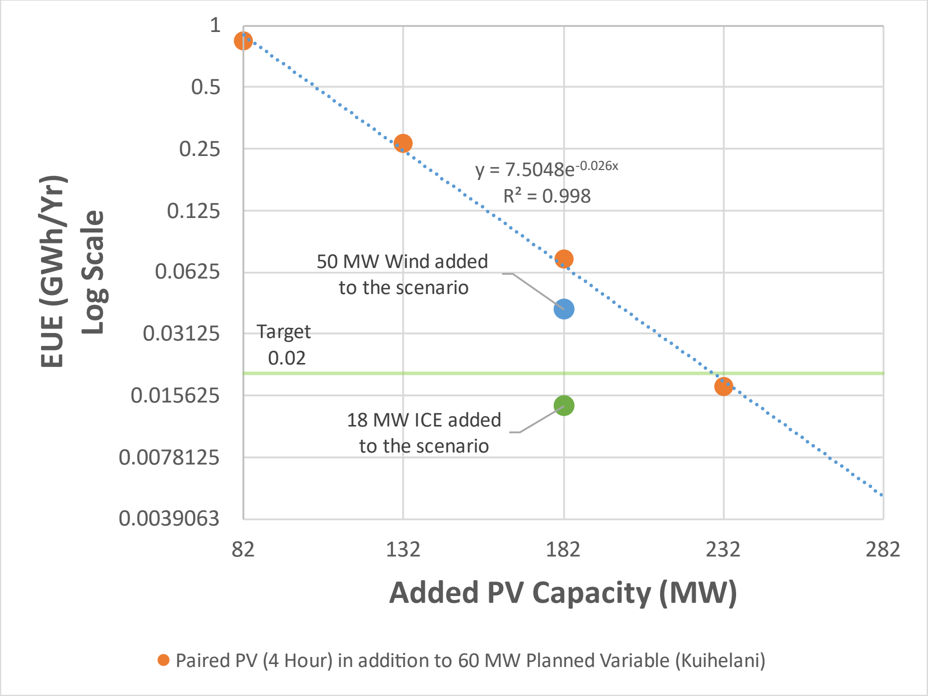


Executive Summary – Key Findings: **A high amount of new variable generation (328 MW of variable generation including Kuihelani Solar and 82 MW PV+BESS / wind) is needed with no new firm additions to meet LOLE and EUE standards**

Probabilistic Resource Adequacy Analysis, year 2030
Kuihelani Only with PV+BESS Sensitivities : Kuihelani, 60 MW wind, 22 MW PV+BESS, plus incremental 50 MW PV+BESS additions
Planned Resources: 60 MW
Beyond Planned Resources: 82 MW (60 MW of wind and 22 MW PV+BESS)

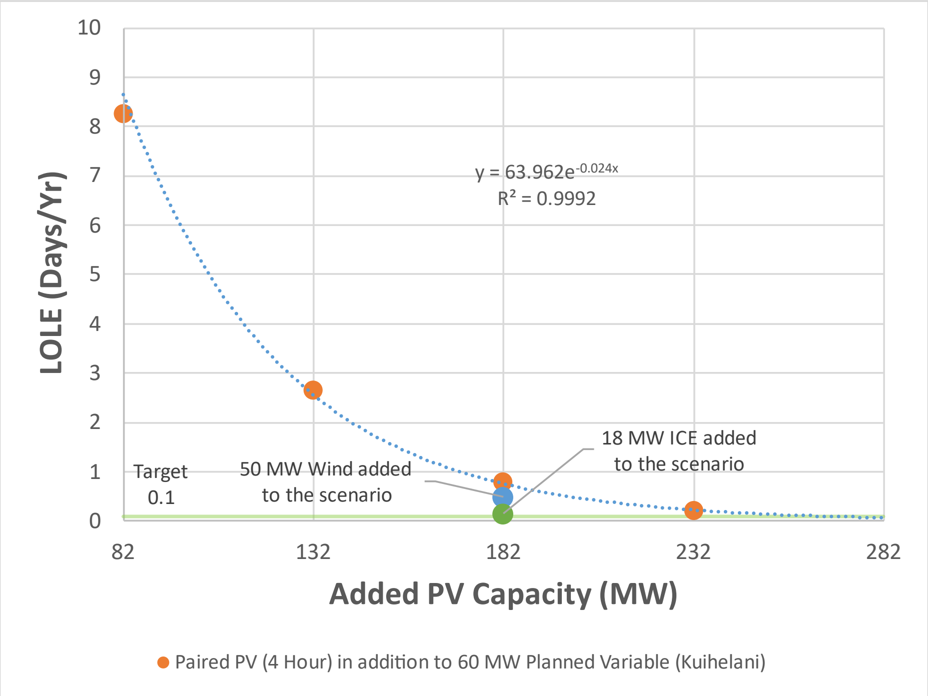
Given no new firm generation additions, incremental PV+BESS additions were tested in the orange data points. The analysis suggests 232 MW of additional PV+BESS meets the EUE target but not the LOLE target. To meet the LOLE target, extrapolating the data, an additional 36 MW of PV+BESS is needed to meet the LOLE target. In total, 328 MW of variable renewables in this case (60 MW Kuihelani, 82 MW PV+BESS / wind, 186 MW additional PV+BESS based on curve fit) is similar to the Base case with 291 MW of variable renewables and 40 MW of standalone storage. Shown in the green data points, 100 MW of additional PV+BESS for a total of 242 MW of renewable resources plus 18 MW of firm generation will provide a reasonable level of reliability.

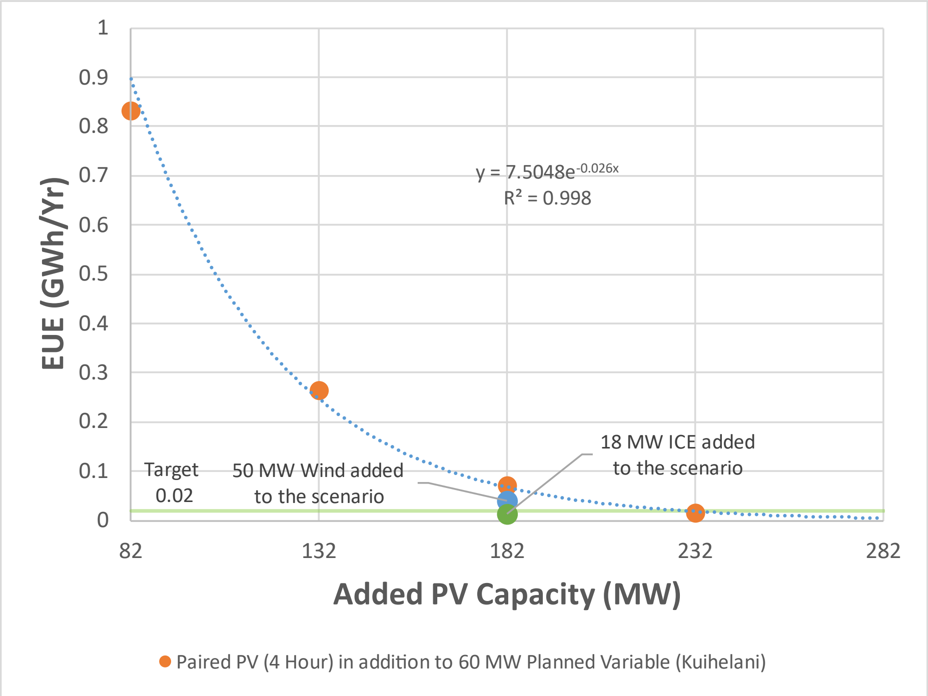




Executive Summary – Key Findings: **Resource portfolio diversity is important to balance diminishing returns on reliability improvements when adding increasing amounts of a single resource type**

As observed in the Kuihelani Solar Only with ICE firm generation sensitivities, the increasing additions of the same resource type have diminishing returns on improvements to reliability. At 182 MW of new renewables, adding 18 MW of ICE (green data point) improves reliability more than another 50 MW of PV+BESS (right most orange data point).





Key Inputs and Assumptions, Methodology

Key Inputs and Assumptions

- Sales Forecast
- Fuel Price Forecast
- Resource Cost Forecast
- Regulating Reserve Requirement
- Hourly Dependable Capacity for Energy Reserve Margin
- Variable Renewable Resource Potential
- Renewable Energy Zone Enablement
- Planned Resources
- Near-Term Conditional Fossil Fuel Generation Removal from Service

Key Inputs and Assumptions

The PUC approved March 2022 IGP inputs and assumptions were used for the following assumptions.

- Sales Forecast
- Fuel Price Forecast
- Resource Cost Forecast

Additional assumptions are described below.

- Regulating reserve requirement –The 1-minute and 30-minute regulating reserve requirement was included, as described in the November 2021 GNA Methodology Report
- Hourly Dependable Capacity for Energy Reserve Margin – The hourly dependable capacity (HDC) for variable renewables was based on the 80th percentile calculation methodology discussed with the TAP.
- Variable Renewable Resource Potential – Consistent with the approved March 2022 IGP inputs and assumptions, the analyses used the Alt-1 scenario that was developed in NREL's revised Assessment of Wind and Photovoltaic Technical Potential for the Hawaiian Electric Company. Because a high amount of capacity was identified for slopes up to 15%, the resource potential was not split further for slopes up to 30%.

See Assessment of Wind and Photovoltaic Technical Potential for the Hawaiian Electric Company

Key Inputs and Assumptions – Renewable Energy Zones

Renewable Energy Zone (REZ) upgrades are composed of two costs:

- Transmission Network Expansion costs – transmission upgrades not associated with a particular REZ group but are required to support the flow of energy within the transmission system
- REZ Enablements – new or upgraded transmission lines and new or expanded substations required to connect the transmission hub of each REZ group to the nearest transmission substation

In this analysis, only the REZ enablement costs were included.

- No transmission network expansion costs were included
- Additional details on the REZ and identified infrastructure, requirements, and costs were discussed in the Hawaiian Electric Transmission REZ Study, filed as part of the November 2021 GNA Methodology Report

See Hawaiian Electric Transmission REZ Study

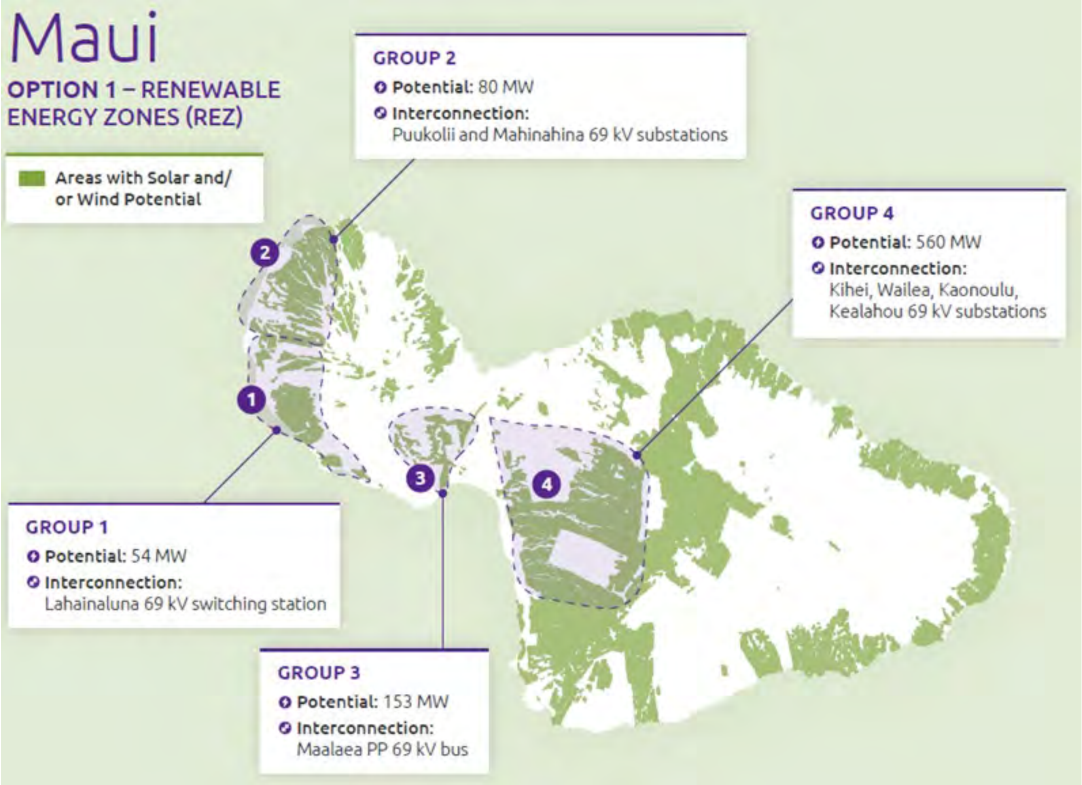
Key Inputs and Assumptions – Renewable Energy Zones

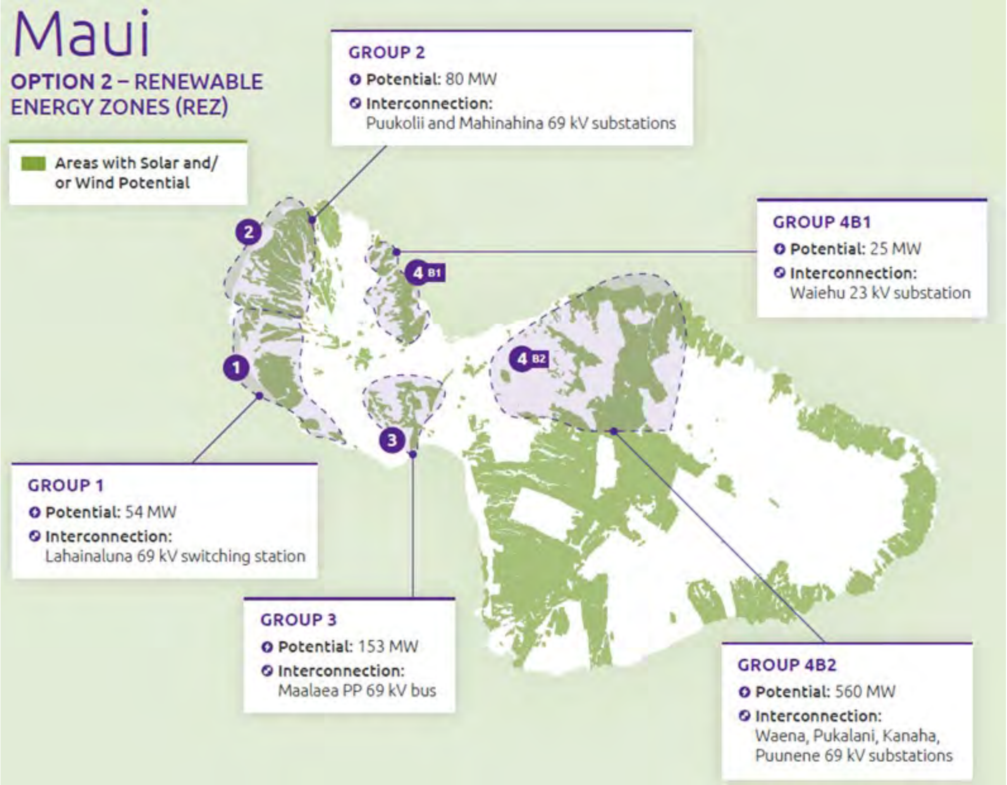
In order to model a reasonable number of candidate resource options, the REZ groups were aggregated by similar REZ enablement cost for modeling in RESOLVE.

- Group A in RESOLVE (287 MW) – Group 1, 2, 3 from the REZ Study
- Group B in RESOLVE (560 MW) – Group 4A from the REZ Study
- Group C in RESOLVE (585 MW) – Group 4B1, 4B2 from the REZ Study

Key Inputs and Assumptions – Renewable Energy Zones Modeled in RESOLVE

The maps below indicate the location of Group 1, 2, 3, 4/4A, 4B1, and 4B2 that were modeled in RESOLVE.





Key Inputs and Assumptions – Planned Resources

The RESOLVE model assumes 2027 as the first year to build new resources. Resources assumed in-service prior to 2027 are shown below. Existing PPAs are assumed to terminate at the end of their contract term, allowing RESOLVE to re-optimize the capacity, energy and other grid services the projects previously provided. For example, Kaheawa Wind Power 1 (30 MW) is assumed to expire in 2027.

Resource	PV (MW)	BESS (MW/MWh)
Kuihelani Solar	60	60/240
Paeahu Solar	15	15/60
Kamaole Solar	40	40/160
Kahana Solar	20	20/80
Pulehu Solar[1]	40	40/160
Waena BESS[2]	N/A	40/160
CBRE Phase 2 Small Projects	8.475	-
CBRE Phase 2 RFP	25	25/100

1. Pulehu Solar withdrew from the RFP process on May 4, 2022
2. Waena BESS application is pending approval

Key Inputs and Assumptions – Near-Term Conditional Fossil Fuel Removal from Service

Hawaiian Electric assumed that certain amounts of firm fossil fuel generation would not be available for dispatch for the purposes of identifying Grid Needs. The planning assumptions noted below do not imply that Hawaiian Electric will retire the amount of firm generation capacity in the years indicated. Actual removal is conditioned upon a number of factors including, whether sufficient resources have been acquired and placed into service to provide replacement grid services, reliability, resilience considerations, among others.

- Remove Kahului Power Plant no later than 2027 (32 MW) (environmental regulations)
- Remove Maalaea 10-13 by 2027 (49 MW) (estimated end of life based on lack of spare parts)
  - M13 – May 2025
  - M11 – September 2025
  - M12 – May 2026
  - M10 – September 2026
- Remove Maalaea 4-9 in 2030 (33 MW)

Key Inputs and Assumptions – Near-Term Conditional Fossil Fuel Removal from Service

The lack of available spare parts for Maalaea 10-13 may cause these units to be removed from service. The figure below provides an illustration of when end of life may be reached for each unit, given the Company's current stock of spare parts. A similar situation where spare parts become unavailable could occur for Maalaea 4-9.

Therefore, as a planning exercise, it is prudent to evaluate the near-term grid needs assuming Maalaea 10-13 and Maalaea 4-9 are removed from service.

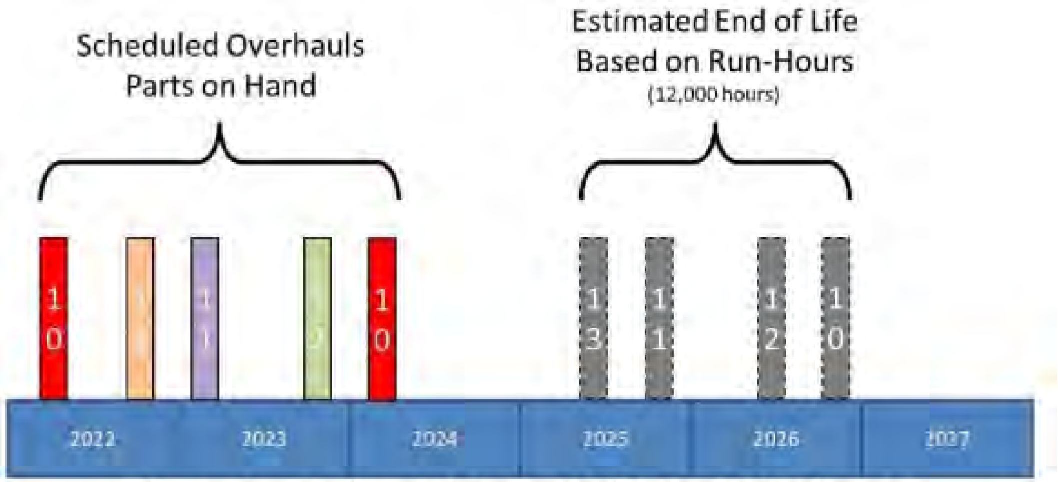
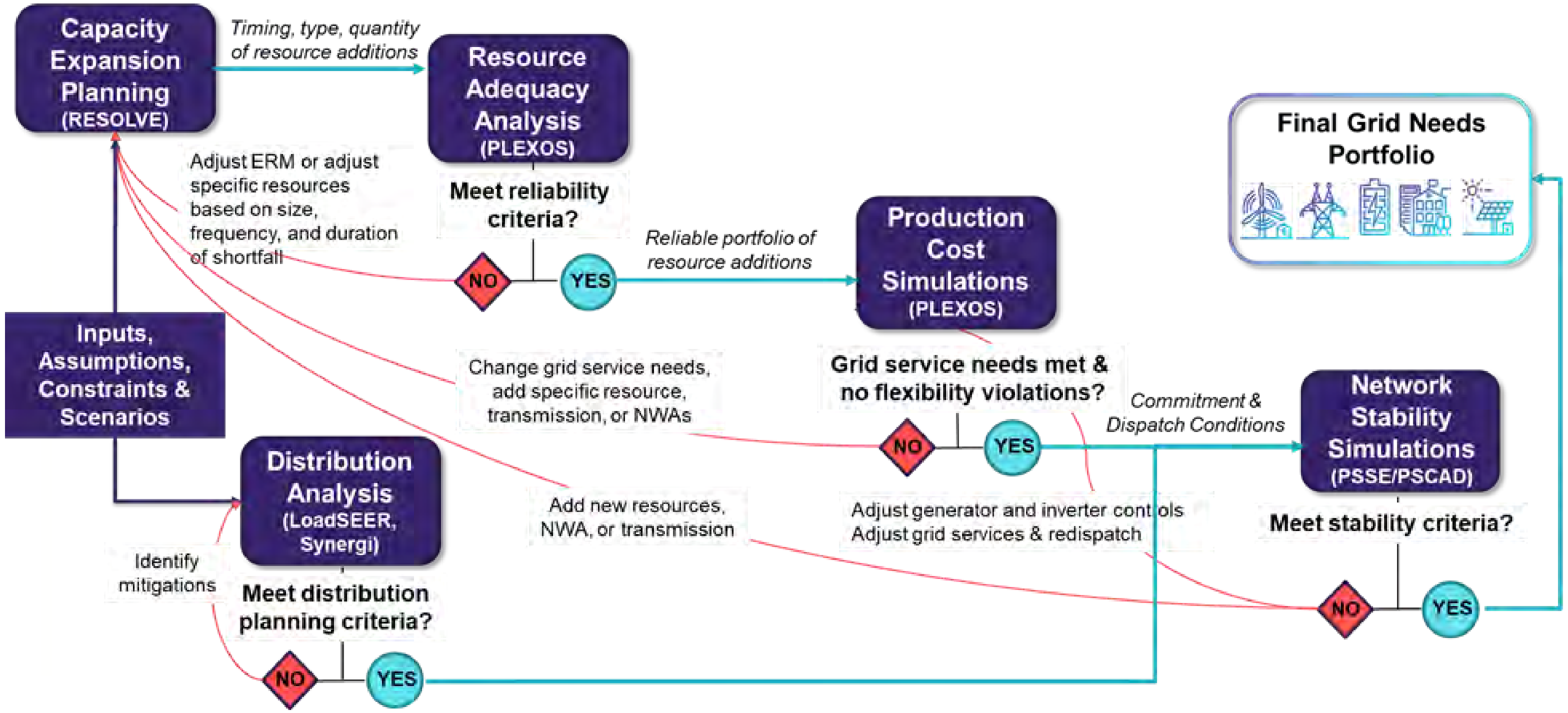


Figure 1 – Estimated End of Life for M10 thru 13

Methodology

- Grid Needs Assessment Methodology
- Define Grid Needs
- Capacity Expansion (RESOLVE)
- Resource Adequacy (PLEXOS)
- Production Cost Simulation (PLEXOS)

Grid Needs Assessment (GNA) Methodology



- The grid needs assessment focuses on the first three steps of the methodology through capacity expansion planning, resource adequacy, and production cost simulations.
- The PUC approved March 2022 IGP Inputs and Assumptions were used in this analysis.
- The methodology is consistent with the November 2021 Grid Needs Assessment and Solution Evaluation Methodology.

GNA Methodology – RESOLVE and PLEXOS Models

1. RESOLVE – Used to determine the optimal type, quantity, and timing of resource additions across a range of constraints to provide directional Grid Needs under various scenarios
   a. The planning assumptions are used to determine a Base portfolio of Grid Needs as well as evaluate resource portfolios under low load, high load, and faster customer technology adoption scenarios
   b. The outputs of RESOLVE are intended to be directional only and are not intended to be a prescriptive pathway
2. PLEXOS – Used to evaluate the energy reserve margin (ERM) and conduct probabilistic analyses on the RESOLVE resource plans for resource adequacy, verify the hourly operations and dispatch of the resources on the system and evaluate production cost
   a. The capacity need was informed by the magnitude and duration of unserved energy observed where the net load, increased by the 30% ERM guideline, was not met by existing resources.
   b. The need was further analyzed using a probabilistic approach endorsed by the TAP. The probabilistic analyses examined 5 weather years for PV and wind, 50 random generator outages for a total of 250 model iterations. The results were then used to calculate loss of load expectation, loss of load events, loss of load hours, and expected unserved energy.
   c. After evaluating the reliability of the resource plan, the operations and dispatch of the resource portfolio was analyzed to examine how the new resources would be operated in future years and evaluate the production cost

Grid Needs means the specific grid services (including but not limited to capacity, energy, and ancillary services) identified in the Grid Needs Assessment, including transmission and distribution system needs that may be addressed through a Non-Wires Alternative.

Capacity Expansion Plans

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Customer Technology Adoption is a Priority

2030 Customer Technology (incremental from 2021 levels)	Peak Load Impact (MW)	Impact to Sales (GWh)	Approximate Quantity
Energy Efficiency	24	170	N/A
Electric Vehicles	10	52	17,466
Private Rooftop Solar	56 (Installed Capacity)	95	7,114
Private BESS	43 MW / 114 MWh (Installed Capacity)	-5	7,275
Non-DER/EV Time-of-Use	1.2	N/A	N/A

Customer technology adoption is considered first in meeting grid needs. Procurement targets identified through the GNA analyses are to meet the residual grid needs after accounting for forecasted EE, EV, DER, and non-DER/EV TOU. 30 MW of Battery Bonus and grid services aggregation are currently being pursued and future DER programs (and included in the analyses) will provide additional flexibility to contribute to grid energy and capacity needs. These customer resources, when acquired cost-effectively, are critical to meeting the needs of the grid.

Further analyses can be completed during the solution sourcing phase of IGP to identify appropriate incentives to design new programs that achieve the forecasted amounts of DER and EE, i.e., evaluate the “freeze” cases.

Capacity Expansion Plans – Scenario Analysis

- **Base Scenario** – Assumes the base set of IGP sales and fuel price forecasts from the PUC approved March 2022 Inputs and Assumptions, in-service of S1/S2/CBRE projects. Existing power purchase agreements are assumed to terminate at the end of their current contract term. Existing fossil fuel generating units continue through the study period, unless otherwise noted. New variable renewable resources are allowed to be built up to the NREL Alt-1 resource potential.

- **Low Load Scenario** – Assumes the set of IGP sales forecasts that reduce customer demand including the high Distributed Energy Resource (DER), high Energy Efficiency (EE), and low Electric Vehicle (EV) forecasts. Together, these forecast layers provide a low load to bookend or bound future, plausible demand that Hawaiian Electric should plan to serve. Other planning assumptions follow the Base Scenario.

- **High Load Scenario** – Assumes the set of IGP sales forecasts that increase customer demand including the low DER, low EE, and high EV forecasts. Together, these forecast layers provide a high load to bookend or bound future, plausible demand that Hawaiian Electric should plan to serve. Other planning assumptions follow the Base Scenario.

- **Faster Customer Technology Adoption Scenario** – Assumes the set of IGP sales forecasts for high adoption levels of customer technologies including DER, EE, and EV. As a result, this sales forecast trends between the base and high load bookend.

Capacity Expansion Plans – Scenario Analysis

The table below provides the forecast assumptions for EE, DER, EV and Time-of-Use (TOU) load shapes associated with customers who do not have DER or EV for the Base, Low Load, High Load, and Faster Customer Technology Adoption (Faster Tech) cases.

Forecast Layer	Base	Low Load	High Load	Faster Tech
EE	Base	High	Low	High
DER	Base	High	Low	High
EV	Base	Low	High	High
EV Charging Shape	Managed	Managed	Unmanaged	Managed
Non-DER, Non-EV TOU	Base	High	Low	High

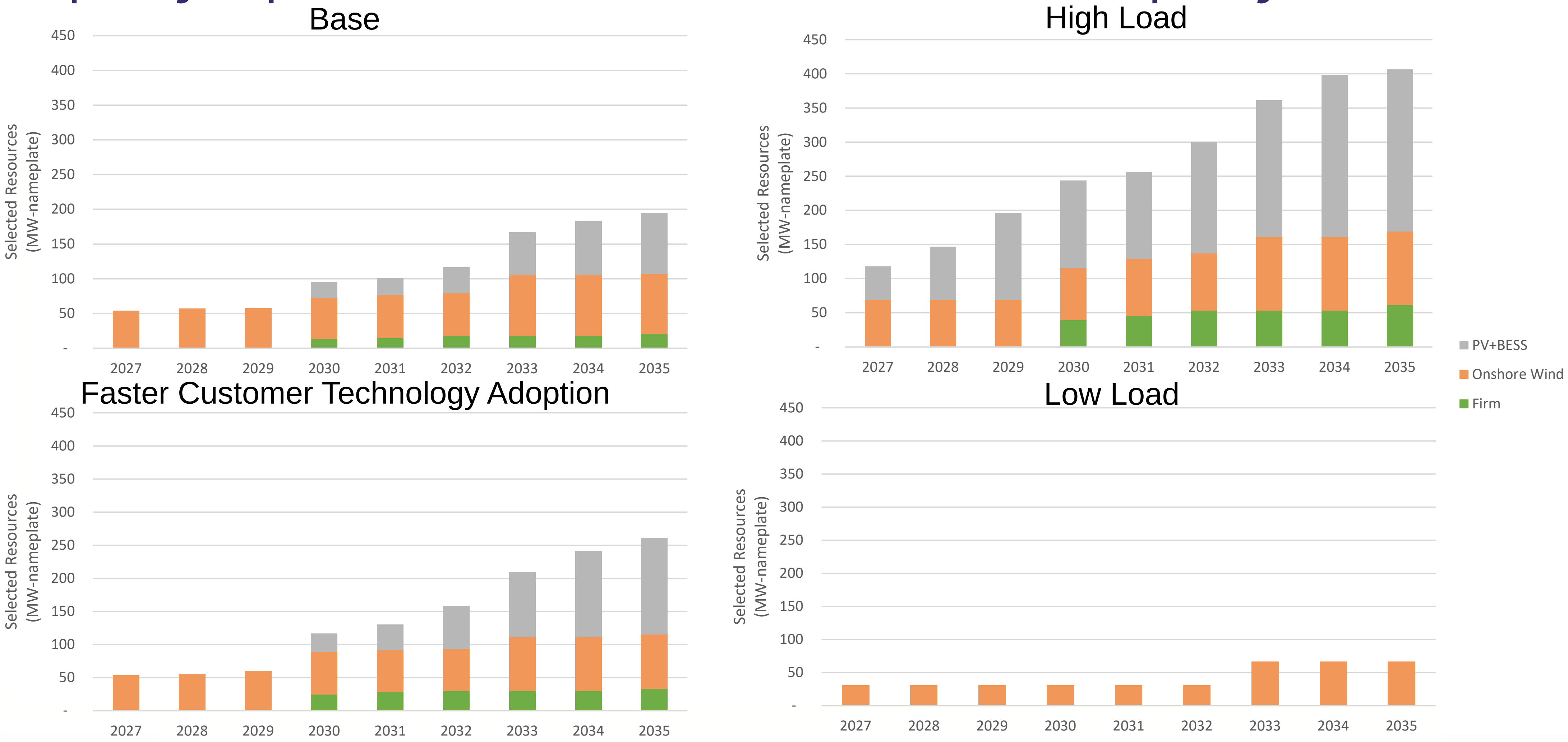
Capacity Expansion Plans – Resource Plans

The following slides show the least-cost plans as optimized in the RESOLVE model for the various scenarios and high/low load bookends. The modeling results demonstrate that the resource mix is consistent across the various futures depending on the level of load to be served. Wind is the first choice because of its lower cost ($/kWh basis) and higher capacity factor compared to PV+BESS. However, PV+BESS continues to be selected to meet the grid needs through 2035. These resources continue to be cost-effective with the REZ costs that were modeled.

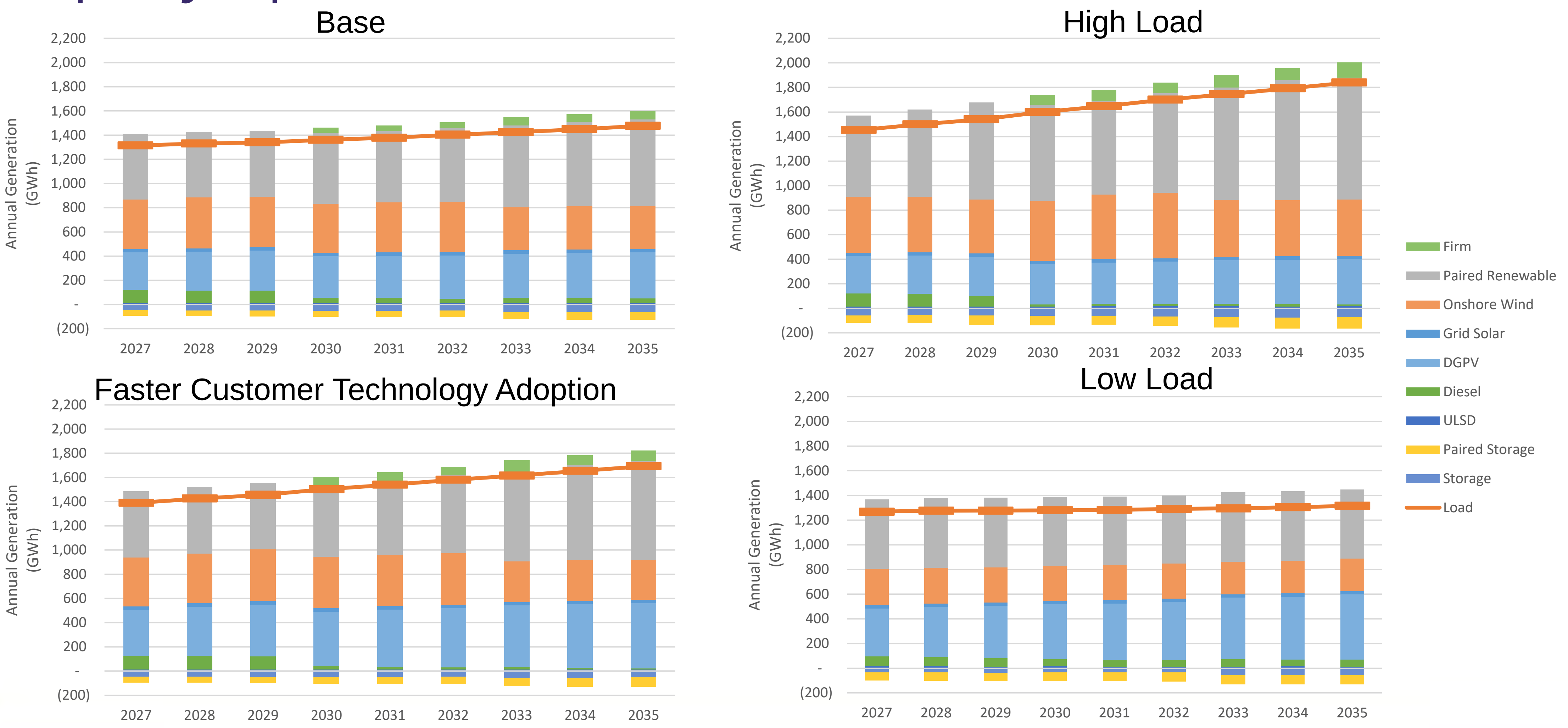
Customer resources are significant contributors to reducing supply-side needs. Additional grid-scale resources would be needed if customer resources are not adopted in significant amounts as shown on Slide 26. This is observed on the energy chart on Slide 31, and the reduced amount of resources selected by the model in the low load scenario. However, in a decarbonized scenario where load grows due to electrification of transportation, the effects can be seen in the high load scenario where significant additional resources are needed.

In all cases, fossil fuel use declines significantly as firm generation is used primarily as stand-by generation when other renewable resources (i.e., wind and solar) are not available.

Capacity Expansion Plans – Incremental Installed Capacity



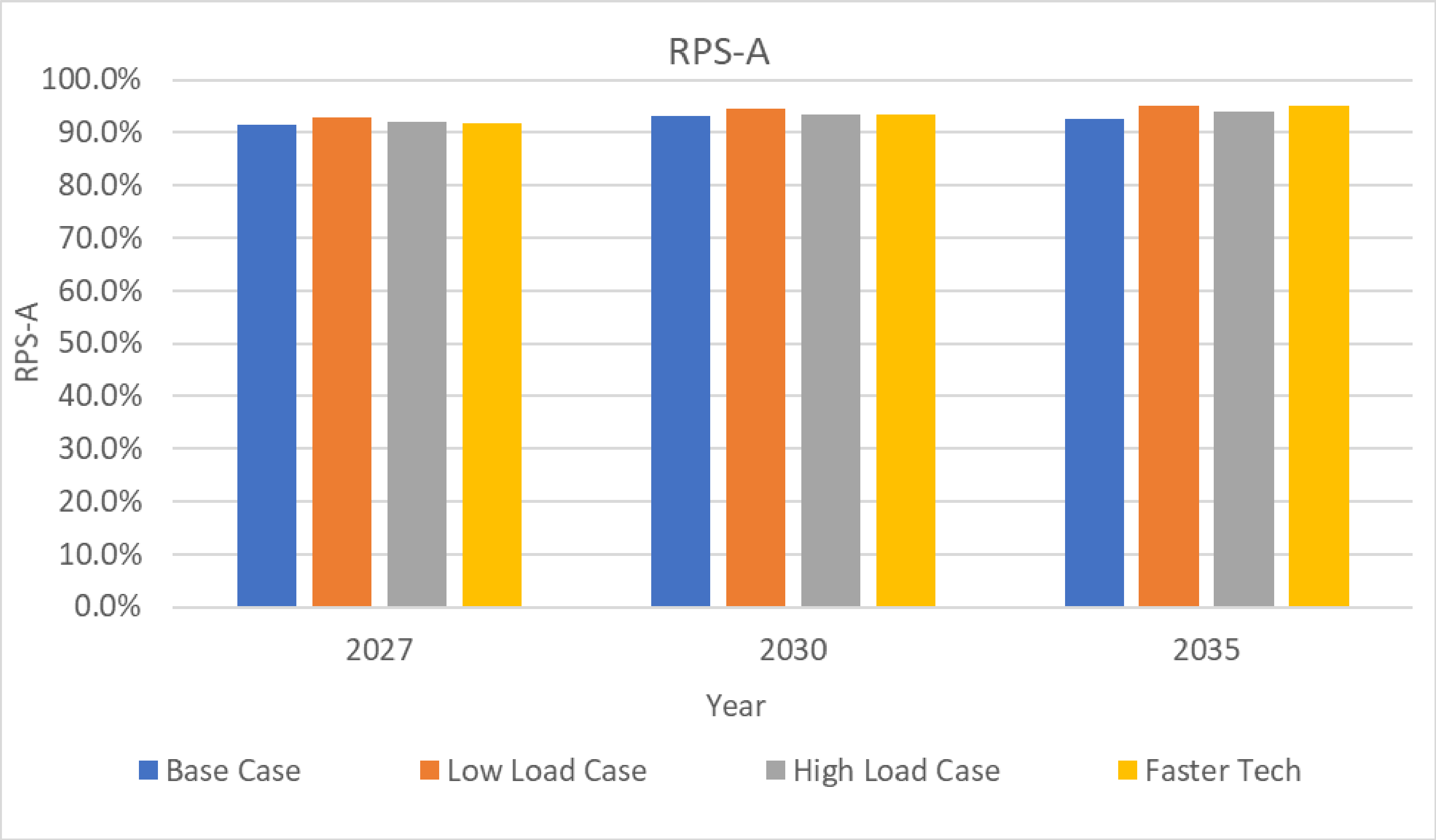
Capacity Expansion Plans – Annual Generation



Detailed Resource Plan

Year	Base Case	High Load	Low Load	Faster Tech
2027	30 MW Kaheawa Wind Power 1 Removed 9.47 MW Kahului 1-2 Removed 23 MW Kahului 3-4 Removed 49.36 MW Maalaea 10-13 Removed Install 54 MW Onshore Wind - Zone C	30 MW Kaheawa Wind Power 1 Removed 9.47 MW Kahului 1-2 Removed 23 MW Kahului 3-4 Removed 49.36 MW Maalaea 10-13 Removed Install 69 MW Onshore Wind - Zone C Install 27 MW Paired PV with 94 MWh Battery - Zone B Install 22 MW Paired PV with 54 MWh Battery - Zone C	30 MW Kaheawa Wind Power 1 Removed 9.47 MW Kahului 1-2 Removed 23 MW Kahului 3-4 Removed 49.36 MW Maalaea 10-13 Removed Install 31 MW Onshore Wind - Zone C	30 MW Kaheawa Wind Power 1 Removed 9.47 MW Kahului 1-2 Removed 23 MW Kahului 3-4 Removed 49.36 MW Maalaea 10-13 Removed Install 54 MW Onshore Wind - Zone C
2028	Install 3 MW Onshore Wind - Zone C	Install 10 MW Paired PV with 21 MWh Battery - Zone B Install 19 MW Paired PV - Zone B		Install 2 MW Onshore Wind - Zone C
2029		Install 34 MW Paired PV with 109 MWh Battery - Zone B Install 15 MW Paired PV with 5 MWh Battery - Zone C		Install 4 MW Onshore Wind - Zone C
2030	33 MW Maalaea 4-9 Removed Install 13 MW CC Install 3 MW Onshore Wind - Zone C Install 22 MW Paired PV with 22 MWh Battery - Zone C	33 MW Maalaea 4-9 Removed Install 39 MW CC Install 8 MW Onshore Wind - Zone C	33 MW Maalaea 4-9 Removed	33 MW Maalaea 4-9 Removed Install 25 MW CC Install 4 MW Onshore Wind - Zone C Install 28 MW Paired PV with 28 MWh Battery - Zone C
2031	Install 2 MW CC Install 2 MW Onshore Wind - Zone C Install 3 MW Paired PV with 3 MWh Battery - Zone C	Install 3 MW CC Install 7 MW Onshore Wind - Zone C Install 4 MW CT		Install 3 MW CC Install 10 MW Paired PV with 10 MWh Battery - Zone C
2032	Install 3 MW CC Install 12 MW Paired PV with 20 MWh Battery - Zone C	Installed 8 MW CT Installed 22 MW Paired PV with 68 MWh Battery - Zone B Installed 14 MW Paired PV with 18 MWh Battery - Zone C		Install 2 MW CC Install 19 MW Paired PV with 35 MWh Battery - Zone C Install 8 MW Paired PV with 18 MWh Battery - Zone B
2033	21 MW Kaheawa Wind Power 2 Removed 21 MW Auwahi Wind Removed Install 25 MW Onshore Wind - Zone C Install 25 MW Paired PV with 54 MWh Battery - Zone C	21 MW Kaheawa Wind Power 2 Removed 21 MW Auwahi Wind Removed Install 24 MW Onshore Wind - Zone C Install 13 MW Paired PV with 27 MWh Battery - Zone C Install 23 MW Paired PV with 61 MWh Battery - Zone B	21 MW Kaheawa Wind Power 2 Removed 21 MW Auwahi Wind Removed Install 36 MW Onshore Wind - Zone C	21 MW Kaheawa Wind Power 2 Removed 21 MW Auwahi Wind Removed Install 18 MW Onshore Wind - Zone C Install 1 MW Paired PV with 3 MWh Battery - Zone C Install 32 MW Paired PV with 102 MWh Battery - Zone B
2034	Install 5 MW Paired PV with 13 MWh Battery - Zone B Install 11 MW Paired PV with 8 MWh Battery - Zone C	Install 36 MW Paired PV with 102 MWh Battery - Zone B Install 2 MW Paired PV - Zone C Install 1 MW Biomass		Install 16 MW Paired PV with 38 MWh Battery - Zone B Install 16 MW Paired PV with 55 MWh Battery - Zone C
2035	Install 2 MW CC Install 7 MW Paired PV with 23 MWh Battery - Zone B Increase Paired PV by 3 MW - Zone C	Install 8 MW Biomass		Install 4 MW Biomass Install 14 MW Paired PV with 21 MWh Battery - Zone B Install 2 MW Paired PV with 14 MWh Battery - Zone C

Capacity Expansion Plans – RPS-A



Despite the change in forecasted loads and resource selection across the Base, Low Load, High Load, and Faster Customer Tech cases, the resulting RPS-A is consistently high and ahead of mandated targets. This indicates that the favorable economics of adding low-cost renewables is driving their selection in the resource plans ahead of RPS mandates.

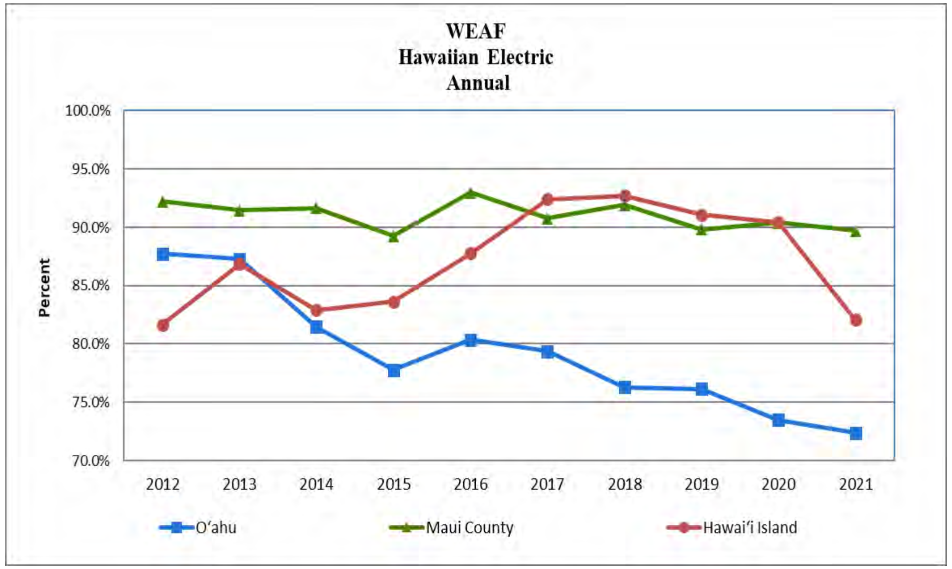
Capacity Expansion Plans – Thermal HDC and ERM Target Sensitivity

- Based on TAP feedback, applying an hourly dependable capacity (HDC) for firm thermal generation and evaluation of different levels of energy reserve margin (ERM) were tested to ensure that the optimal least-cost resource mix did not change significantly. This analysis iterates, in part, on the probabilistic resource adequacy analysis discussed later in this report.

- Currently, existing and new firm generation have an HDC of 1 or 100%, where there are no assumed derates for maintenance or forced outages. Capacity expansion plans were developed to test the sensitivity of the thermal resource selection to the ERM target and HDC.

- A thermal HDC was applied in RESOLVE to represent the availability of thermal units after planned and unplanned outages using the 2021 Weighted Equivalent Availability Factor (WEAF). This metric is the percentage of time a fleet of generating units is available to generate electricity, weighted for generator size where larger generators have a greater effect on WEAF.

- The table on the following slide are the results of this analysis. It is observed that the resource mix of wind, solar, and energy storage is unchanged. The amount of firm generation that is selected by RESOLVE changes based on the ERM. This suggests that the ERM and HDC do not impact building of low-cost renewables (i.e., firm generation does not displace lower cost solar and wind resources); however, firm generation depends on the level of reliability desired.



Capacity Expansion Plans – Thermal HDC and ERM Target Sensitivity

Year 2030	Base	30% ERM, Thermal HDC	20% ERM, Thermal HDC	15% ERM, Thermal HDC	10% ERM, Thermal HDC
Existing firm HDC (%)	100%	89.72%	89.72%	89.72%	89.72%
New firm HDC (%)	100%	97.4%	97.4%	97.4%	97.4%
ERM Requirement (%)	30%	30%	20%	15%	10%
New Firm (selected by RESOLVE)	13	26	12	4	0
Existing Firm	126	126	126	126	126
Paired PV	22	25	18	17	14
Onshore Wind	60	60	62	62	64
Paired Storage (MW/MWh)	22 MW / 22 MWh	25 MW / 25 MWh	18 MW / 18 MWh	17 MW / 17 MWh	14 MW / 14 MWh

Capacity Expansion Plans – Key Findings

- In the near-term, the same type of resources are being selected by RESOLVE through 2034 and the resource build only varies in quantity and timing across the different scenarios.
  - While the plans diverge slightly in 2035 when the faster customer technology adoption and high load scenarios build a new resource (biomass), the selected capacity is small (4-8 MW).
  - This indicates that in the near-term, the grid needs are similar and that further load scenarios may not be needed.
  - The resulting RPS-A for these plans is consistently high and further supports that the load bookends are an appropriate framework for considering load scenarios.
- Regardless of the HDC applied to thermal units or ERM target percentage, high amounts of renewables (wind, PV+BESS) are still consistently selected in RESOLVE
  - Firm thermal capacity is still needed for ERM targets between 15-30%

RESOLVE to PLEXOS – Detailed Resource Plan

Adjustments were made to the RESOLVE resource plan to reflect minimum installed capacities for thermal generating units.

*The combined cycle resource selected by RESOLVE is much smaller than the assumed block size for a 1x1 LM2500 CC (48 MW). However, because RESOLVE built this resource to meet a capacity need for ERM, the combined cycle was converted to two 9 MW ICE units.

Year	Base Case (RESOLVE)	18 MW ICE (PLEXOS)
2027	30 MW Kaheawa Wind Power 1 Removed 9.47 MW Kahului 1-2 Removed 23 MW Kahului 3-4 Removed 49.36 MW Maalaea 10-13 Removed Install 54 MW Onshore Wind - Zone C	30 MW Kaheawa Wind Power 1 Removed 9.47 MW Kahului 1-2 Removed 23 MW Kahului 3-4 Removed 49.36 MW Maalaea 10-13 Removed Install 54 MW Onshore Wind - Zone C
2028	Install 3 MW Onshore Wind - Zone C	Install 3 MW Onshore Wind - Zone C
2029		
2030	33 MW Maalaea 4-9 Removed **Install 13 MW CC*** Install 3 MW Onshore Wind - Zone C Install 22 MW Paired PV with 22 MWh Battery - Zone C	33 MW Maalaea 4-9 Removed **Install 18 MW ICE** Install 3 MW Onshore Wind - Zone C Install 22 MW Paired PV with 22 MWh Battery - Zone C
2031	**Install 2 MW CC*** Install 2 MW Onshore Wind - Zone C Install 3 MW Paired PV with 3 MWh Battery - Zone C	Install 2 MW Onshore Wind - Zone C Install 3 MW Paired PV with 3 MWh Battery - Zone C
2032	**Install 3 MW CC*** Install 12 MW Paired PV with 20 MWh Battery - Zone C	Install 12 MW Paired PV with 20 MWh Battery - Zone C
2033	21 MW Kaheawa Wind Power 2 Removed 21 MW Auwahi Wind Removed Install 25 MW Onshore Wind - Zone C Install 25 MW Paired PV with 54 MWh Battery - Zone C	21 MW Kaheawa Wind Power 2 Removed 21 MW Auwahi Wind Removed Install 25 MW Onshore Wind - Zone C Install 25 MW Paired PV with 54 MWh Battery - Zone C
2034	Install 5 MW Paired PV with 13 MWh Battery - Zone B Install 11 MW Paired PV with 8 MWh Battery - Zone C	Install 5 MW Paired PV with 13 MWh Battery - Zone B Install 11 MW Paired PV with 8 MWh Battery - Zone C
2035	**Install 2 MW CC*** Install 7 MW Paired PV with 23 MWh Battery - Zone B Increase Paired PV by 3 MW - Zone C	Install 7 MW Paired PV with 23 MWh Battery - Zone B Increase Paired PV by 3 MW - Zone C

Energy Reserve Margin Analysis

Hawaiian Electric

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Energy Reserve Margin

Historically, Maui's capacity planning criteria was defined by Rule 1 with consideration for a reserve margin:

- The total capability of the system must at all times be equal to or greater than the summation of the following:
  - The capacity needed to serve the estimated system peak load less the total amount of interruptible load;
  - The capacity of the unit scheduled for maintenance; and
  - The capacity that would be lost by the forced outage of the largest available unit in service
- Consideration will be given to maintaining a reserve margin of approximately 20 percent based on Reserve Ratings

The current Energy Reserve Margin criteria was developed to consider the dynamic nature of variable resources and limited duration storage

- The ERM is the percentage which the system capacity must exceed the system load in each hour
- The hourly evaluation of available energy allows for a statistical representation of the impact of variable and finite resources at all hours of the day
- The ERM for Maui is 30% to provide reasonable reliability reserve to address some level of contingencies, forecast errors, and uncertainties inherent in planning assumptions

Energy Reserve Margin – Scenario Analysis

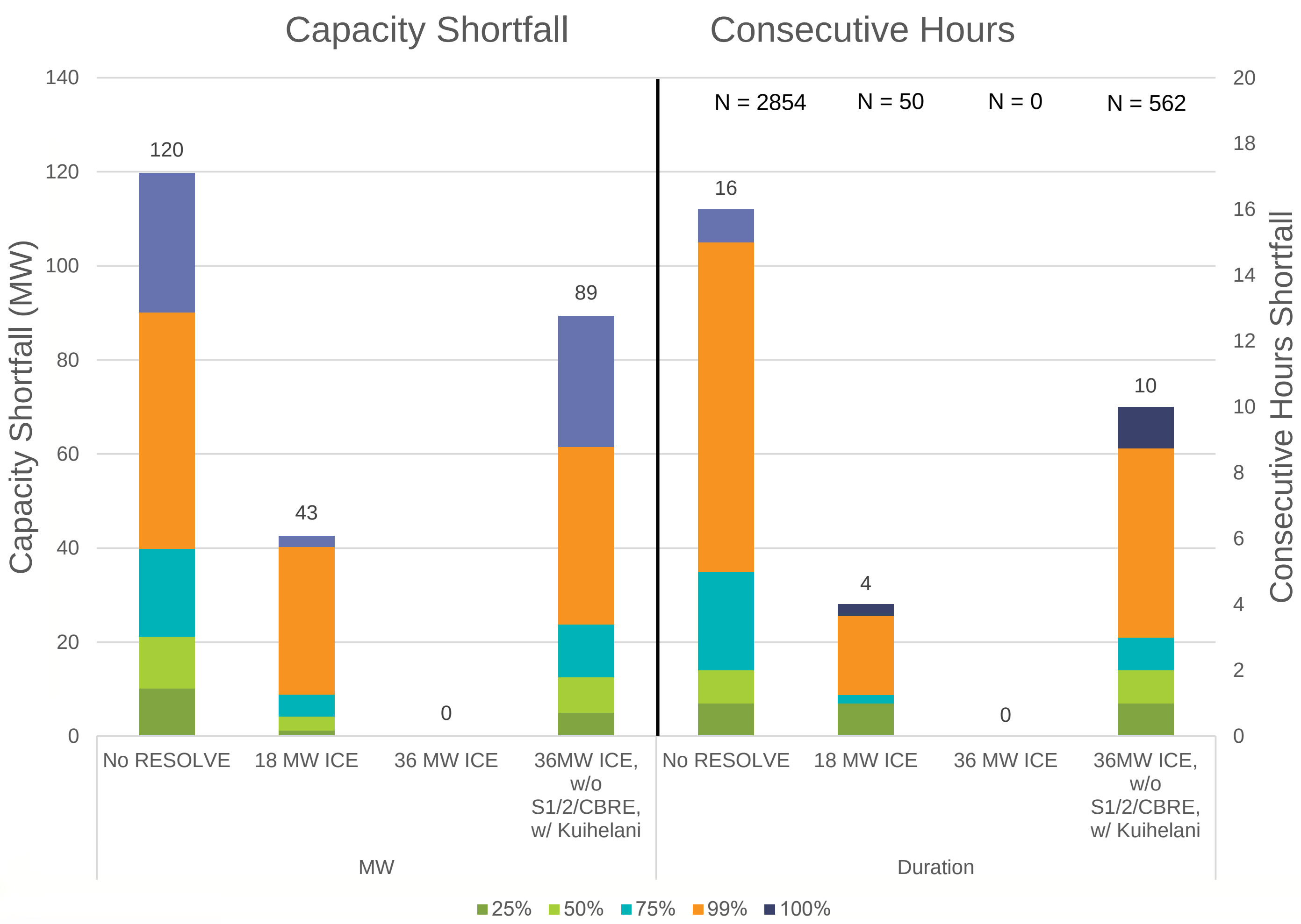
Using the Base scenario as a guide, various scenarios were evaluated to determine the capacity shortfall and consecutive hours of shortfall. These two metrics provide insight into both the size and duration of a capacity shortfall.

- **No Future RESOLVE Resources** – Using the Base scenario, planned resource additions for S1/S2/CBRE and planned removals are included but any selected RESOLVE resources are not included. This scenario will identify the capacity that RESOLVE selected to meet ERM.
- **18 MW ICE** – Using the Base scenario, partial installations of combined cycle that were selected by RESOLVE were accelerated from 2031, 2032 and combined into year 2030 for a total of 18 MW. For capacity planning purposes, this thermal generating resource was represented by 2 x 9 MW ICE units.
- **36 MW ICE** – Using the Base scenario, the partial installations of combined cycle were again converted to 18 MW of ICE. An additional 18 MW of ICE was added and the combined 36 MW was installed in 2027.
- **36 MW ICE, w/o S1/S2/CBRE Ph2, w/ Kuihelani Solar (Kuihelani)** – Using the 36 MW ICE scenario, less certain planned resources were removed from Stage 1, Stage 2, and CBRE Ph 2. Kuihelani was still included because there was relatively more certainty it would be in service compared to other projects.

Energy Reserve Margin – Detailed Resource Plan

Year	No RESOLVE	18 MW ICE	36 MW ICE	36 MW ICE w/o S1/S2/CBRE P2
2027	30 MW Kaheawa Wind Power 1 Removed 9.47 MW Kahului 1-2 Removed 23 MW Kahului 3-4 Removed 49.36 MW Maalaea 10-13 Removed	30 MW Kaheawa Wind Power 1 Removed 9.47 MW Kahului 1-2 Removed 23 MW Kahului 3-4 Removed 49.36 MW Maalaea 10-13 Removed Install 54 MW Onshore Wind - Zone C	30 MW Kaheawa Wind Power 1 Removed 9.47 MW Kahului 1-2 Removed 23 MW Kahului 3-4 Removed 49.36 MW Maalaea 10-13 Removed Install 54 MW Onshore Wind - Zone C Install 36 MW ICE	30 MW Kaheawa Wind Power 1 Removed 9.47 MW Kahului 1-2 Removed 23 MW Kahului 3-4 Removed 49.36 MW Maalaea 10-13 Removed Install 54 MW Onshore Wind - Zone C Install 36 MW ICE
2028		Install 3 MW Onshore Wind - Zone C	Install 3 MW Onshore Wind - Zone C	Install 3 MW Onshore Wind - Zone C
2029				
2030	33 MW Maalaea 4-9 Removed	33 MW Maalaea 4-9 Removed Install 18 MW ICE Install 3 MW Onshore Wind - Zone C Install 22 MW Paired PV with 22 MWh Battery - Zone C	33 MW Maalaea 4-9 Removed Install 3 MW Onshore Wind - Zone C Install 22 MW Paired PV with 22 MWh Battery - Zone C	33 MW Maalaea 4-9 Removed Install 3 MW Onshore Wind - Zone C Install 22 MW Paired PV with 22 MWh Battery - Zone C
2031		Install 2 MW Onshore Wind - Zone C Install 3 MW Paired PV with 3 MWh Battery - Zone C	Install 2 MW Onshore Wind - Zone C Install 3 MW Paired PV with 3 MWh Battery - Zone C	Install 2 MW Onshore Wind - Zone C Install 3 MW Paired PV with 3 MWh Battery - Zone C
2032		Install 12 MW Paired PV with 20 MWh Battery - Zone C	Install 12 MW Paired PV with 20 MWh Battery - Zone C	Install 12 MW Paired PV with 20 MWh Battery - Zone C
2033	21 MW Kaheawa Wind Power 2 Removed 21 MW Auwahi Wind Removed	21 MW Kaheawa Wind Power 2 Removed 21 MW Auwahi Wind Removed Install 25 MW Onshore Wind - Zone C Install 25 MW Paired PV with 54 MWh Battery - Zone C	21 MW Kaheawa Wind Power 2 Removed 21 MW Auwahi Wind Removed Install 25 MW Onshore Wind - Zone C Install 25 MW Paired PV with 54 MWh Battery - Zone C	21 MW Kaheawa Wind Power 2 Removed 21 MW Auwahi Wind Removed Install 25 MW Onshore Wind - Zone C Install 25 MW Paired PV with 54 MWh Battery - Zone C
2034		Install 5 MW Paired PV with 13 MWh Battery - Zone B Install 11 MW Paired PV with 8 MWh Battery - Zone C	Install 5 MW Paired PV with 13 MWh Battery - Zone B Install 11 MW Paired PV with 8 MWh Battery - Zone C	Install 5 MW Paired PV with 13 MWh Battery - Zone B Install 11 MW Paired PV with 8 MWh Battery - Zone C
2035		Install 7 MW Paired PV with 23 MWh Battery - Zone B Increase Paired PV by 3 MW - Zone C	Install 7 MW Paired PV with 23 MWh Battery - Zone B Increase Paired PV by 3 MW - Zone C	Install 7 MW Paired PV with 23 MWh Battery - Zone B Increase Paired PV by 3 MW - Zone C

Energy Reserve Margin – ERM Needs (2030)

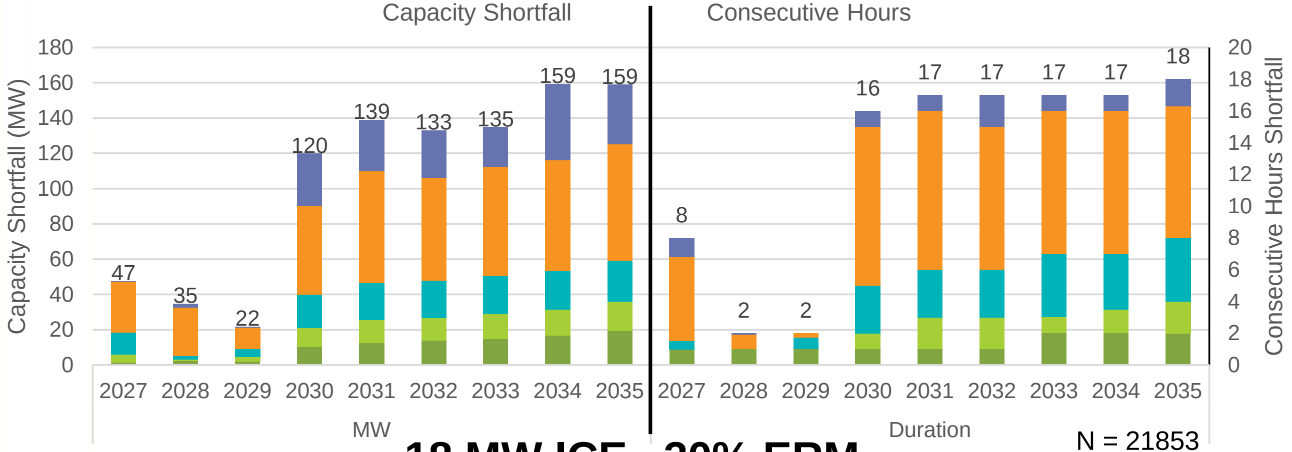


- 30% ERM and p80 HDCs were included in this analysis
- N: Total hours of unserved energy.
- The capacity shortfalls for each hour in 2030 is shown on the left.
- The duration of each capacity shortfall is shown on the right.
- The colors represent percentiles that show the distribution of hourly shortfalls and shortfall durations throughout 2030.

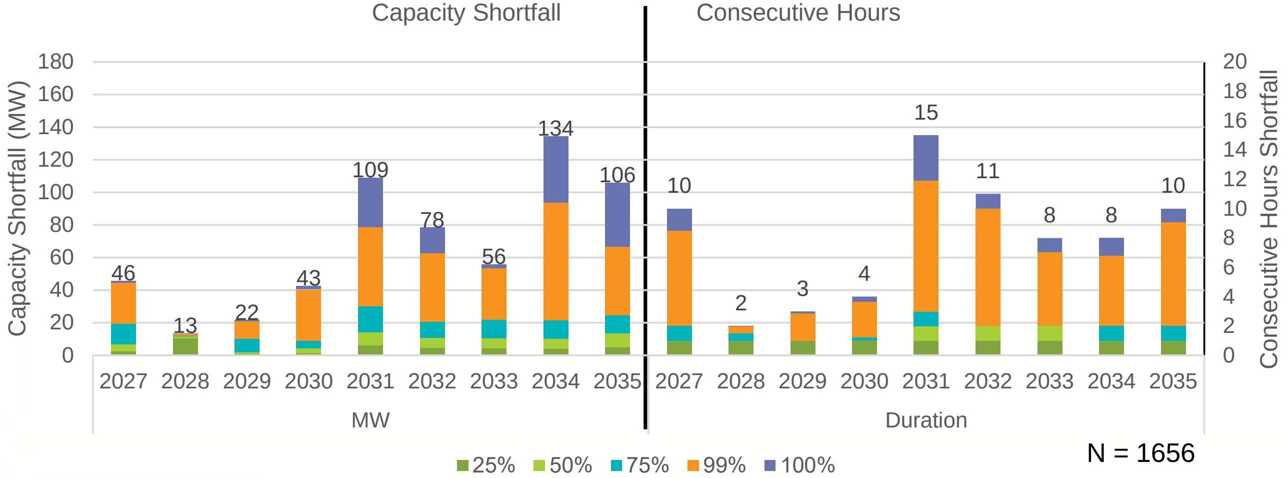
ATTACHMENT 2

Energy Reserve Margin – Annual ERM Needs

No RESOLVE Selected Resources – 30% ERM



18 MW ICE– 30% ERM



2027-2029

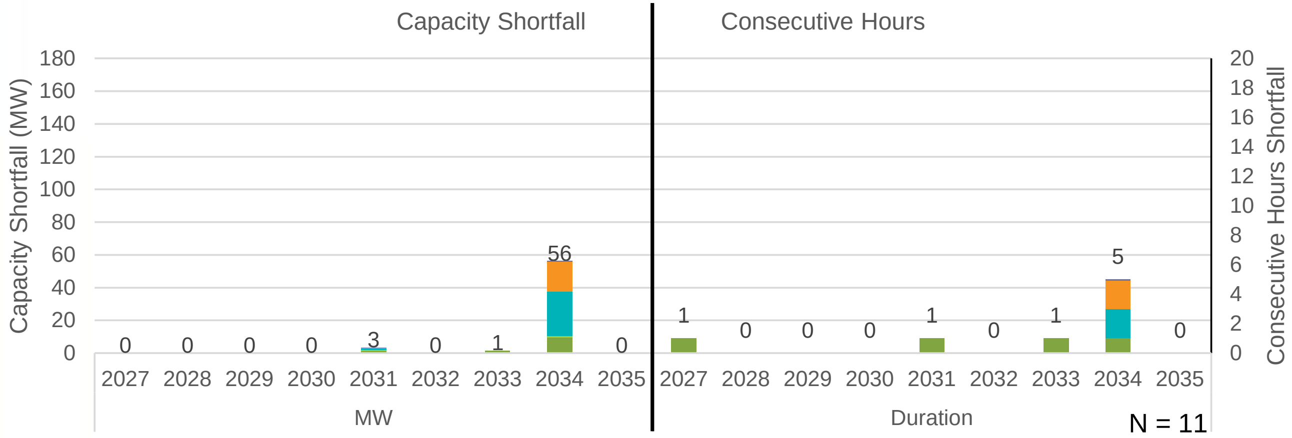
- Capacity shortfalls are due to the removal of Maalaea 10-13 and maintenance of the dual train combined cycles

2030-2035

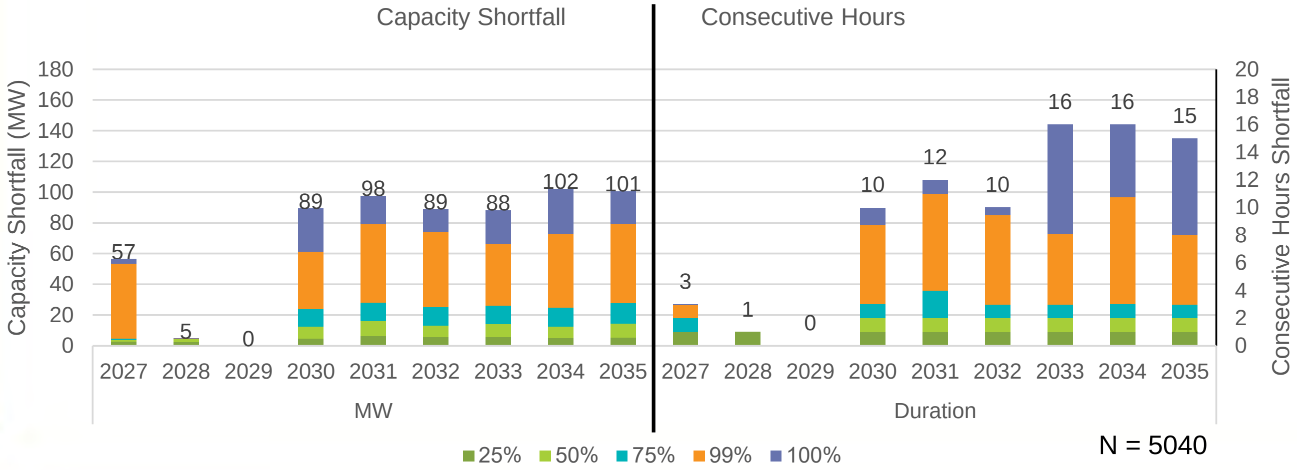
- Capacity shortfalls are due to the removal of Maalaea 4-9
- The addition of 18 MW ICE in 2030 reduces 2030+ shortfalls relative to the no RESOLVE resources case

Energy Reserve Margin – Annual ERM Needs

36 MW ICE – 30% ERM



36 MW ICE, w/o S1/S2/CBRE Ph 2, with Kuihelani – 30% ERM



- **36 MW ICE:**
  - **2034** – Capacity shortfall is due to maintenance on the dual train combined cycles
- **36 MW ICE w/ S1/S2/CBRE Ph 2**
  - **2030-2035** – Capacity shortfalls are due to the removal of Maalaea 4-9

Although 36 MW of ICE is installed in 2027 in both cases, the wind and PV+BESS has a significant impact on the remaining capacity need.

Energy Reserve Margin – Key Findings

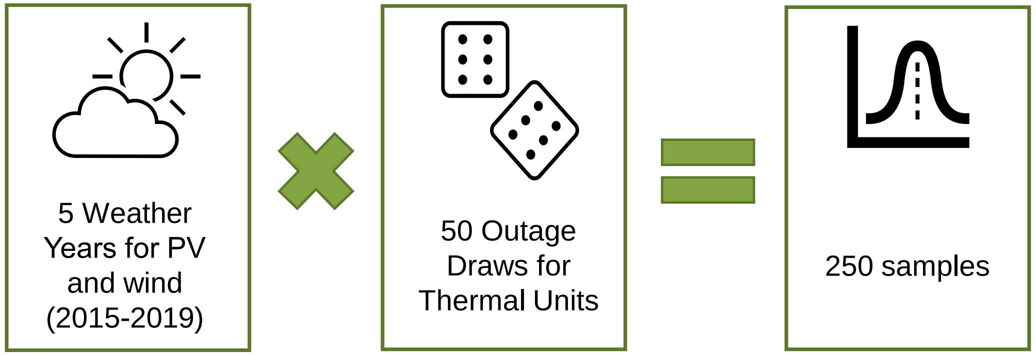
- The No RESOLVE selected resources scenario identified the capacity and duration to be met by future resources.
- Excluding the extreme outliers, at the 99th percentile, a capacity need of 90 MW and 15 consecutive hours in 2030 was determined.
- The 18 MW ICE scenario confirms that there is still a residual ERM need after accounting for the RESOLVE additions so additional capacity is needed.
- The 36 MW ICE scenario shows that additional ICE can solve for residual ERM needs in 2030.
- The 36 MW ICE w/o S1/S2/CBRE Ph 2, w/ Kuihelani scenario shows that a 36 MW additional ICE may not be enough if other planned renewable projects in the resource plan withdraw.
- Grid needs from 2027 – 2035 agree with the general trends highlighted in 2030, that 36 MW of new thermal generation satisfies most of the future ERM needs and that even more capacity, above 36 MW, may be needed if projects from Stage 1, Stage 2, and CBRE are not able to go into service in this timeframe.

Probabilistic Resource Adequacy Analysis

Hawaiian Electric

Hawai'i Powered

Probabilistic Analyses



- A probabilistic framework was developed with and endorsed by the TAP to further examine the resource adequacy of the plans in a selected year.
- Probabilistic resource adequacy is a method to quantify the risk of capacity shortfalls given the uncertainty in future system operating conditions.
- This method utilizes a random sampling approach to define distributions of generating resource availability using an outage rate for thermal generators and historical weather years for variable renewable resources.
- 50 outage draws for thermal generators and 5 weather years for variable renewable resources were examined for a total of 250 samples for each case.

Probabilistic Analyses – Key Metrics

Several metrics can be calculated to characterize the reliability of the resource plan

- LOLE or Loss of Load Expectation is the average number of event-periods per year with unserved load across all simulated random samples. In the Company's analyses, this is defined as days per year.
- LOLEv or Loss of Load Frequency is the average count of events per year with unserved load across all simulated random samples. An event is defined as consecutive hours of unserved load.
- LOLH or Loss of Load Hours is the average number of hours with unserved load across all simulated random samples.
- EUE or Expected Unserved Energy is the average load not served per year across all simulated random samples.

LOLE: Target of 0.1 represents commonly used standard on the US Mainland.

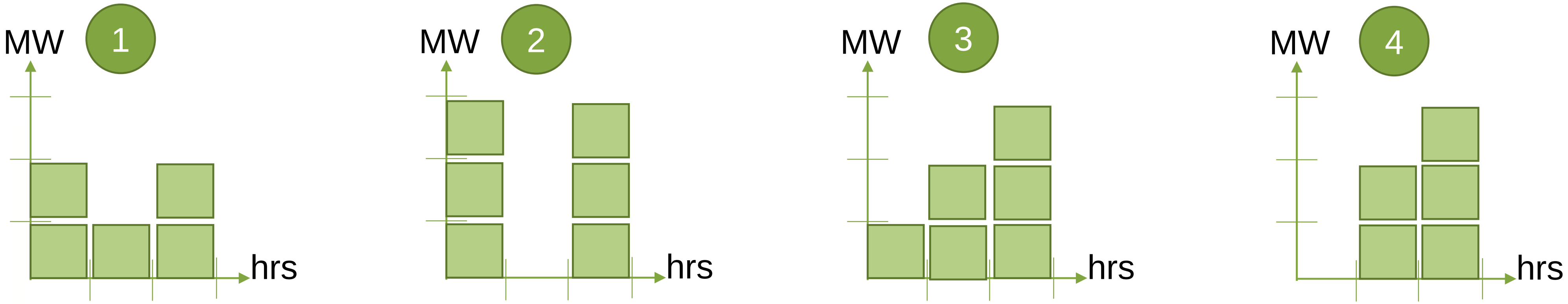
LOLH: Belgium, France, Great Britain, and Poland have a standard of equal to or less than 3 hr/yr.

EUE: Australia/AEMO have a standard of equal to or less than 0.002% of total energy demand. Using the 2030 forecasted net load on Maui, this is equivalent to 20 MWh.

The TAP recommends multiple metrics to assess resource adequacy. Although different jurisdictions use different metrics for their reliability standard, reporting a suite of metrics provides a fuller picture of the reliability of a resource plan. For example, LOLE indicates the number of days of unserved energy but does not indicate the magnitude (EUE), duration (LOLH), or number of events (LOLEv).

See EPRI Report 3002023230, Resource Adequacy for a Decarbonized Future, A Summary of Existing and Proposed Resource Adequacy Metrics, April 2022

Probabilistic Analyses – Key Metrics



Example 1	Example 2	Example 3	Example 4
LOLEv = 1	LOLEv = 2	LOLEv = 1	LOLEv = 1
LOLH = 3	LOLH = 2	LOLH = 3	LOLH = 2
EUE = 5	EUE = 6	EUE = 6	EUE = 5

Illustrative examples of LOLEv, LOLH, and EUE. Each of these metrics characterize the size and duration of unserved energy. One day of unserved energy (LOLE) can consist of one or more unserved energy events. One unserved event (LOLEv) can have a duration of one or multiple hours of unserved energy as long as the unserved energy occurs within a continuous set of hours. The total number of unserved hours is LOLH and the total amount of unserved energy is EUE.

- Examples 1 and 3 have the same LOLEv and LOLH but different EUE
- Examples 1 and 4 have the same LOLEv and EUE but different LOLH
- Examples 2 and 3 have the same EUE but different LOLEv and LOLH

Adapted from Telos Energy

Probabilistic Analyses – Key Findings

The key findings of the probabilistic analyses include:

- Each resource type improves reliability to a different degree. There are diminishing returns with each new addition of a single resource technology to improve reliability.
  - An incremental 50 MW PV+BESS addition to a base of Kuihelani Solar (60 MW) plus 22 MW PV+BESS, 60 MW wind reduced LOLE from **8.27** to **2.66** days/year. Further 50 MW additions had a reduced reduction in LOLE relative to the same base (+100 MW / **0.8** days/yr, +150 MW / **0.21** days/yr). (Slide 52)
  - An incremental 18 MW ICE addition from a base of Kuihelani Solar plus 22 MW PV+BESS, 60 MW wind reduced LOLE from **8.27** to **2.26** days/yr. Further 9 MW additions had a reduced reduction in LOLE relative to the same base (+27 MW / **1.17** days/yr, +36 MW / **0.58** days/yr). (Slide 55)
  - A 9 MW, 12-hour long duration energy storage (LDES) did not provide the same degree of reliability as a 9 MW ICE (36 MW ICE / **0.58** days/yr, 27 MW ICE + 9 MW LDES / **0.62** days/yr)
  - Adding 242 MW of variable generation and 18 MW of firm generation (**0.14** days/yr) or adding 291 MW of variable generation and 40 MW of standalone BESS (**0.14** days/yr) will achieve a similar LOLE as Maui in 2021 (**0.15** days/yr). (Slide 52)
- Due to potential community opposition to new wind plants, the model selected wind was converted to PV + BESS on an energy basis (ratio of 1 MW wind to 2 MW of PV). Probabilistic cases examining the substitution of 50 MW wind for 50 MW PV+BESS and comparison of the removal of 30 MW of wind vs 62 MW PV indicate that while wind improves reliability, PV + BESS improves reliability to a greater degree. (Slide 52)

Probabilistic Analyses – Stakeholder Feedback

The Company has incorporated significant stakeholder feedback into the Maui GNA that was provided by the TAP on the ongoing Oʻahu GNA analyses.

This feedback is reflected in additional cases conducted for the probabilistic analyses including evaluation of:

- Long duration storage
- Finer increments of thermal additions
- Finer increments of PV+BESS additions
- Tradeoffs between continuing existing generation against removal and replacement with new generation

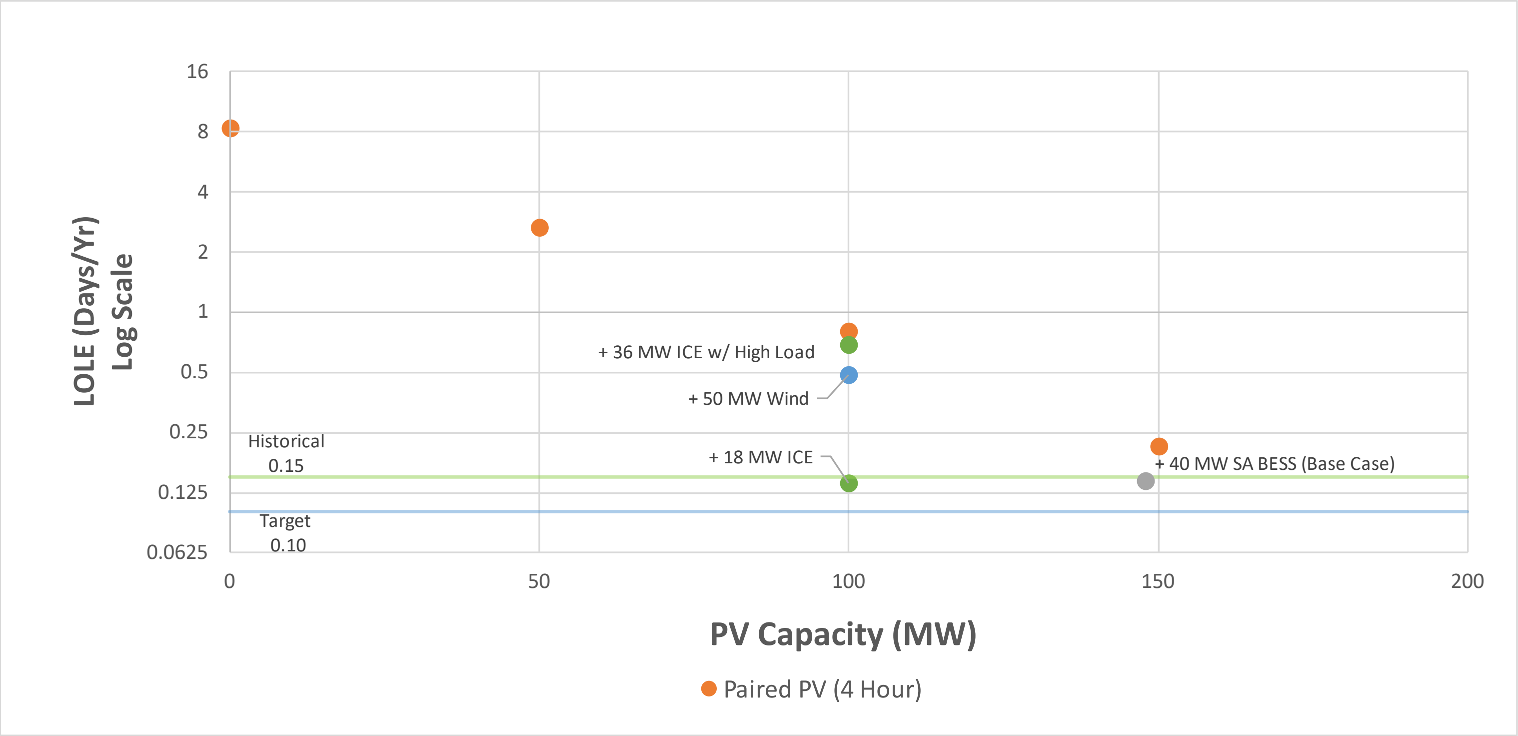
Probabilistic Analyses – Variable Resource Additions

Green = LOLE ≤ 0.10 Days/Yr (US Mainland), LOLH ≤ 3 hrs (Belgium, France, GB, Poland), EUE ≤ 0.002% of load/20 MWh (AEMO)

Year 2030	Existing Firm (MW)	Firm Removed (MW)	Future Firm (MW)	Planned Variable (MW)	Future Variable (MW)	SA BESS (MW)	LOLE (Days/Yr)	LOLEv (Events/Yr)	LOLH (Hours/Yr)	EUE (GWh/Yr)
Reference Case - 2021	240	-	-	-	-	-	0.15	0.16	0.25	0.00
Base Case – w/o S1/S2/CBRE Ph2, w/ Kuihelani	126	-114	0	60	82	0	8.27	13.83	38.37	0.83
Add 50 MW PV+BESS	126	-114	0	60	132	0	2.66	4.90	10.85	0.26
Add 100 MW PV+BESS	126	-114	0	60	182	0	0.80	1.44	2.72	0.07
Add 150 MW PV+BESS	126	-114	0	60	232	0	0.21	0.38	0.67	0.02
Add 100 MW PV+BESS, 18 MW ICE	126	-114	18	60	182	0	0.14	0.24	0.53	0.01
Add 100 MW PV+BESS, 36 MW ICE (High Load Bookend)	126	-114	36	60	182	0	0.68	1.30	2.62	0.08
Add 100 MW PV+BESS, 50 MW wind	126	-114	0	60	232	0	0.48	0.78	1.42	0.04
Base Case, No ICE	126	-114	0	208.5	82	40	0.14	0.31	0.62	0.01

Planned Variable includes: Kuihelani (60 MW), Paeahu (15 MW), Kamaole (40 MW), Kahana (20 MW), Pulehu (40 MW), CBRE Ph 2 (33.5 MW)
Future Standalone BESS includes: Waena BESS (40 MW)
Future Variable selected by RESOLVE includes: Wind (60 MW), PV+BESS (22 MW)

Probabilistic Analyses – Variable Resource Additions



LOLE

Add 100 MW PV+BESS

Add 100 MW PV+BESS, 50 MW onshore wind

Add 150 MW PV+BESS

Historic Level = 0.15

Add 40 MW SA BESS (Base Case, No ICE - includes S1/S2/CBRE Ph2)

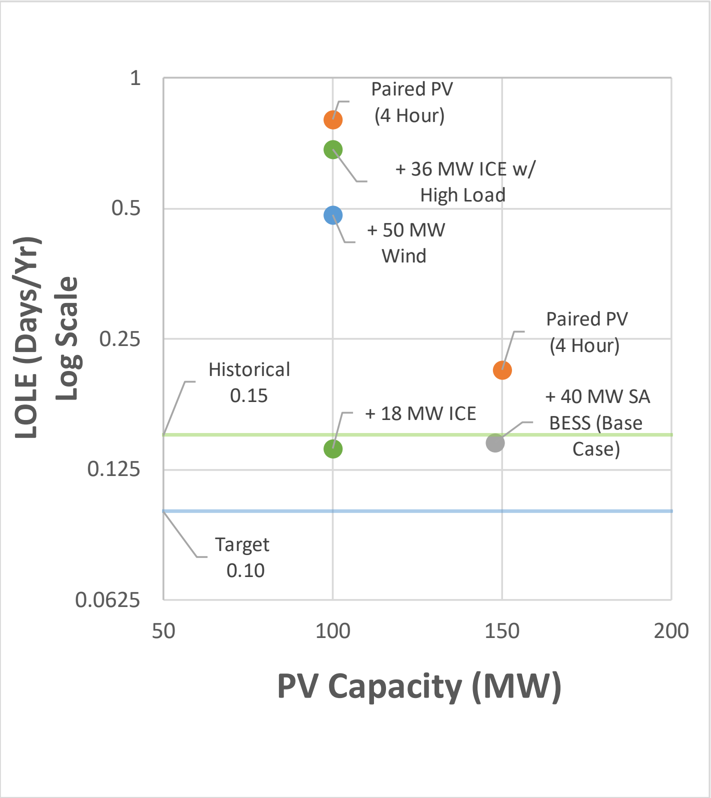
Add 100 MW PV+BESS, 18 MW ICE

US Mainland LOLE = 0.1

Probabilistic Analyses – Variable Resource Additions

LOLE is satisfactory if all the Stage 1, Stage 2, and CBRE Ph2 projects are in service (Base, No ICE Case) relative to historical reliability. Those resources could be replaced by 100 MW of PV paired with 4-hour storage and 18 MW of ICE and achieve a comparable level of reliability (lower green data point).

- With the addition of 100 MW of paired PV and a total of 36 MW of ICE, LOLE would be unsatisfactory in the High Load Bookend (upper green datapoint).
- 50 MW of paired PV improves LOLE more than 50 MW of wind (blue data point compared with the rightmost orange data point).
- 18 MW of thermal improves LOLE more than 50 MW of wind or 50 MW of paired PV (green data point compared with blue and rightmost orange datapoint)
- LOLE is worse than the historical level in the case with 150 MW of paired PV added. In comparison, the Base Case achieves an acceptable LOLE with slightly less paired PV but with the addition of 40 MW of standalone storage (gray datapoint).



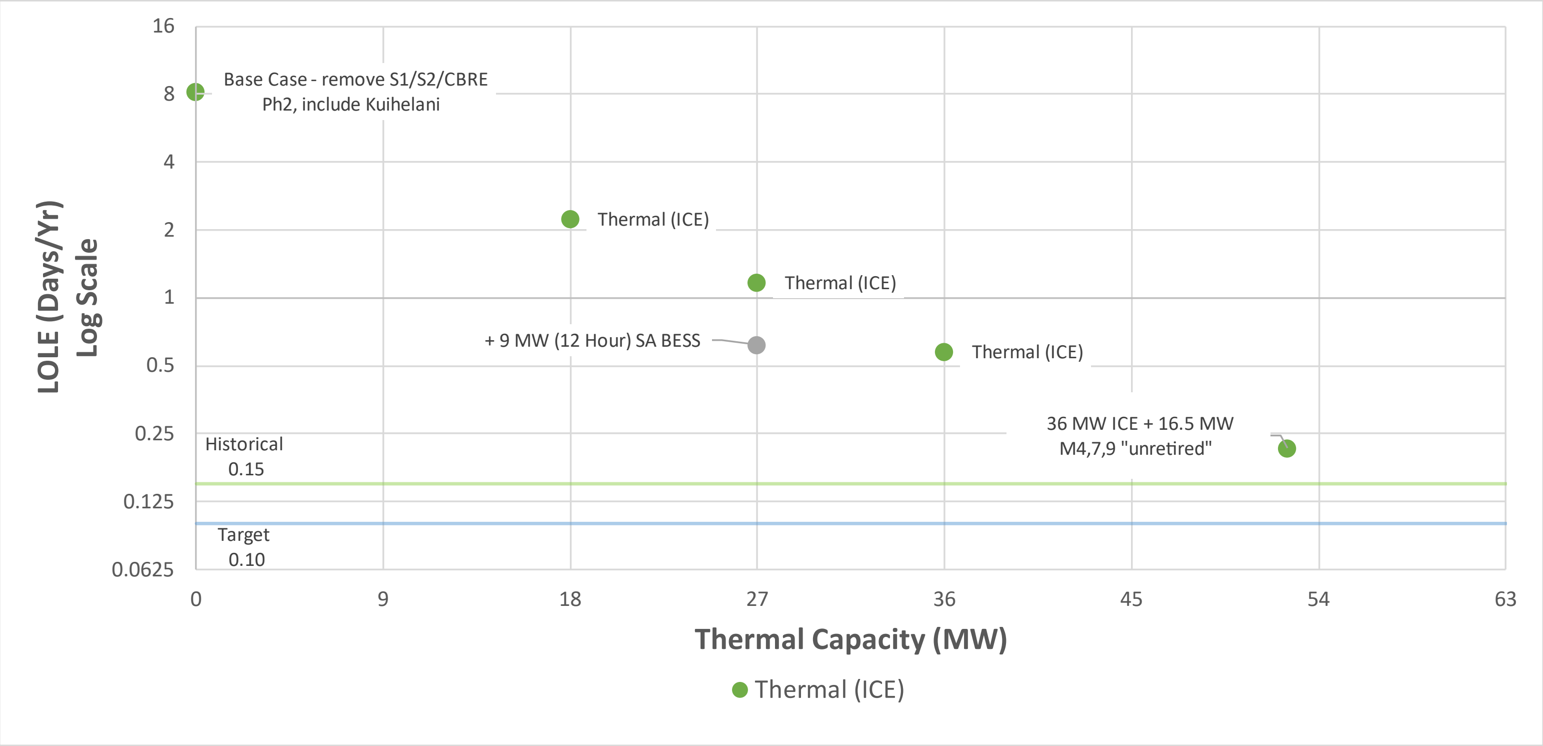
Probabilistic Analyses – Firm Resource Additions

Green = LOLE ≤ 0.10 Days/Yr (US Mainland), LOLH ≤ 3 hrs (Belgium, France, GB, Poland), EUE ≤ 0.002% of load/20 MWh (AEMO)

Year 2030	Existing Firm (MW)	Firm Removed (MW)	Future Firm (MW)	Planned Variable (MW)	Future Variable (MW)	SA BESS (MW)	LOLE (Days/Yr)	LOLEv (Events/Yr)	LOLH (Hours/Yr)	EUE (GWh/Yr)
Reference Case - 2021	240	-	-	-	-	-	0.15	0.16	0.25	0.00
Base Case - remove S1/S2/CBRE Ph2, include Kuihelani Solar	126	-114	0	60	82	0	8.27	13.83	38.37	0.83
Add 18 MW ICE	126	-114	18	60	82	0	2.26	3.57	9.97	0.21
Add 27 MW ICE	126	-114	27	60	82	0	1.17	1.84	4.70	0.10
Add 36 MW ICE	126	-114	36	60	82	0	0.58	0.91	2.41	0.05
Add 36 MW ICE, not retired: M4, M7, M9	142.5	-97.5	36	60	82	0	0.22	0.33	0.73	0.01
Add 27 MW ICE, add 9 MW 12-Hour BESS	126	-114	27	60	82	9	0.62	1.01	2.68	0.06

Planned Variable includes: Kuihelani (60 MW), Paeahu (15 MW), Kamaole (40 MW), Kahana (20 MW), Pulehu (40 MW), CBRE Ph 2 (33.5 MW)
Future Standalone BESS includes: Waena BESS (40 MW)
Future Variable selected by RESOLVE includes: Onshore Wind (60 MW), PV+BESS (22 MW)

Probabilistic Analyses – Firm Resource Additions



LOLE

Base Case - remove S1/S2/CBRE Ph2, include Kuihelani

Add 18 MW ICE

Add 27 MW ICE

Add 27 MW ICE, add 9 MW 12-Hour BESS

Add 36 MW ICE

Add 36 MW ICE, unretire M4, M7, M9

Historic Level = 0.15

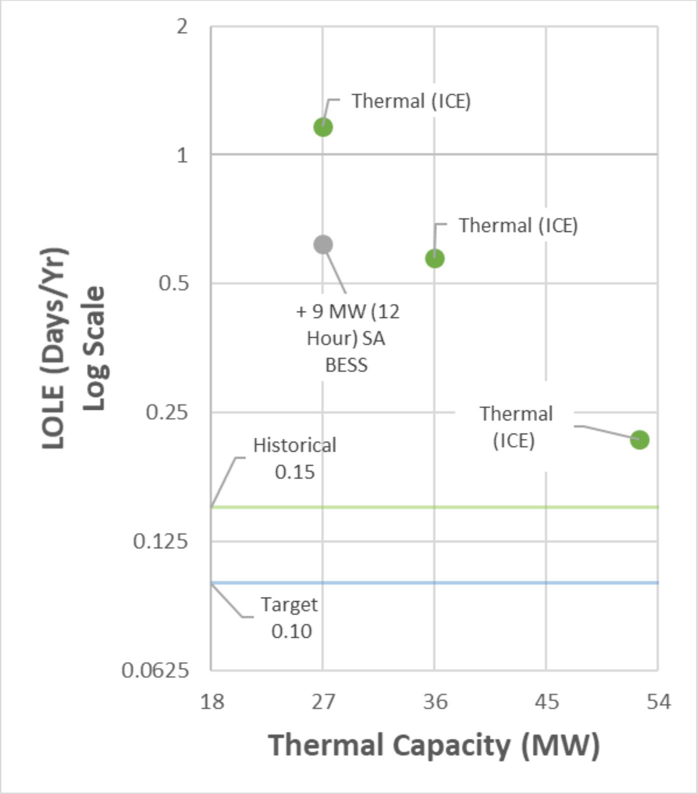
US Mainland LOLE = 0.1

Probabilistic Analyses – Firm Resource Additions

With the Stage 1, Stage 2, and CBRE Ph2 projects not in service (except Kuihelani which is in service), LOLE (8 days/year, see previous slide) does not meet the historical level.

- LOLE still does not meet the historical level with an additional 36 MW thermal and with existing units M4, M7, and M9 remaining in service and does not meet the US Mainland standard of 0.1 (lowest green datapoint).
- 9 MW of firm thermal generation improves LOLE more than 9 MW of 12-hour stand-alone BESS (middle green datapoint compared with gray datapoint).

Long duration energy storage may not necessarily reduce firm generation needs; however, additional solar + BESS would help to reduce firm generation needs. To meet immediate reliability needs, firm generation can adequately address reliability risks if solar + BESS resources are unable to reach commercial operations.



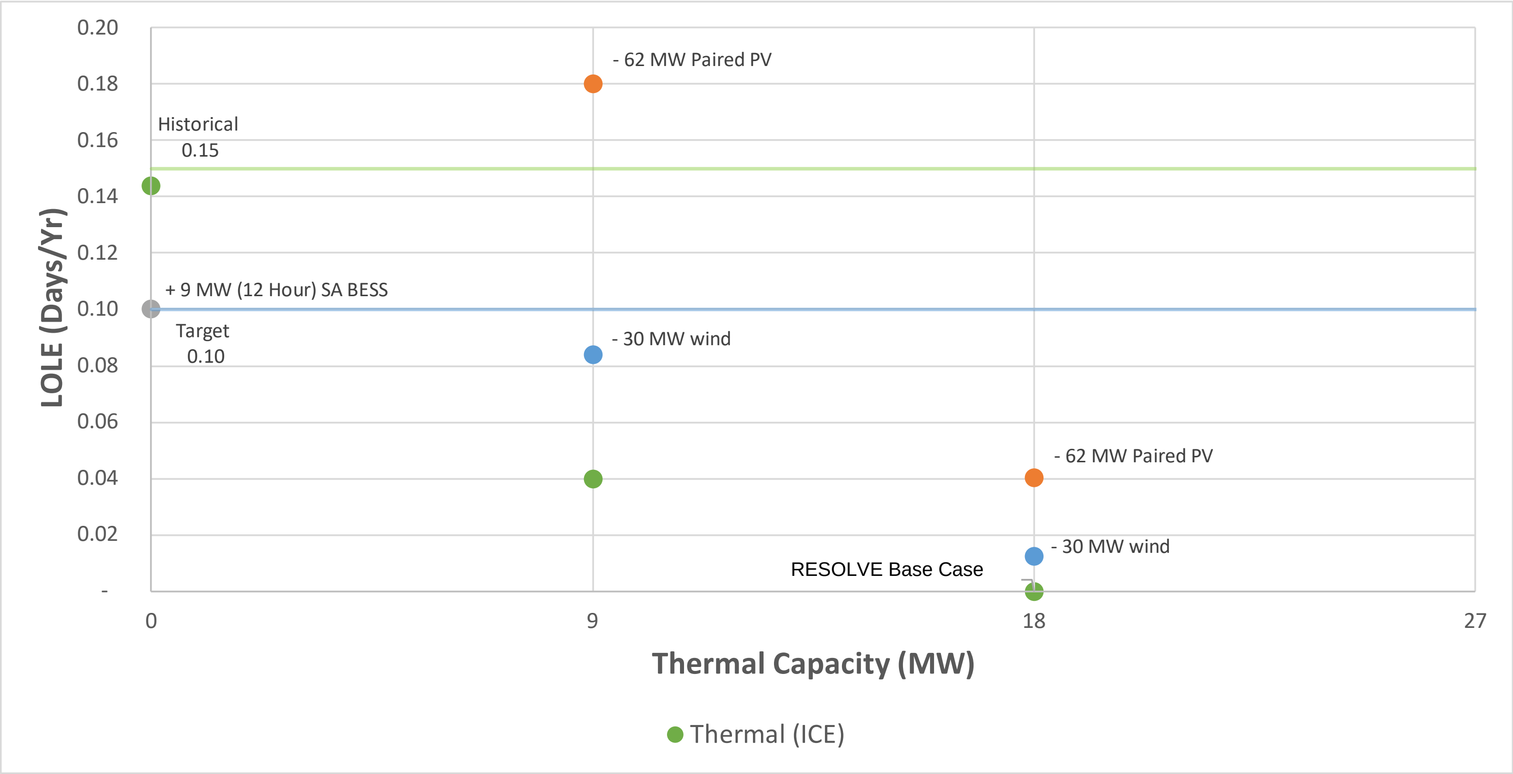
Probabilistic Analyses – Firm/Variable Resource Additions

Green = LOLE ≤ 0.10 Days/Yr (US Mainland), LOLH ≤ 3 hrs (Belgium, France, GB, Poland), EUE ≤ 0.002% of load/20 MWh (AEMO)

Year 2030	Existing Firm (MW)	Firm Removed (MW)	Future Firm (MW)	Planned Variable (MW)	Future Variable (MW)	SA BESS (MW)	LOLE (Days/Yr)	LOLEv (Events/Yr)	LOLH (Hours/Yr)	EUE (GWh/Yr)
Reference Case - 2021	240	-	-	-	-	-	0.15	0.16	0.25	0.00
Base Case, No ICE	126	-114	0	208.5	82	40	0.14	0.31	0.62	0.01
Add 9 MW ICE	126	-114	9	208.5	82	40	0.04	0.07	0.13	0.00
Add 9 MW ICE, remove 62 MW PV	126	-114	9	208.5	20	40	0.18	0.34	0.62	0.01
Add 9 MW ICE, remove 30 MW wind	126	-114	9	208.5	52	40	0.08	0.15	0.33	0.01
Add 18 MW ICE (RESOLVE Base Case)	126	-114	18	208.5	82	40	0	0	0	0
Add 18 MW ICE, remove 62 MW PV	126	-114	18	208.5	20	40	0.04	0.08	0.12	0.00
Add 18 MW ICE, remove 30 MW wind	126	-114	18	208.5	52	40	0.01	0.03	0.04	0.00
Add 9 MW 12-Hour BESS	126	-114	0	208.5	82	49	0.10	0.22	0.49	0.01

Planned Variable includes: Kuihelani (60 MW), Paeahu (15 MW), Kamaole (40 MW), Kahana (20 MW), Pulehu (40 MW), CBRE Ph 2 (33.5 MW)
Future Standalone BESS includes: Waena BESS (40 MW)
Future Variable selected by RESOLVE includes: Onshore Wind (60 MW), PV+BESS (22 MW)

Probabilistic Analyses – Firm/Variable Resource Additions



LOLE

Remove 62 MW Paired PV (4hr) and Remove 30 MW Wind

Remove 30 MW Wind

Nominal Thermal Capacity

Firm thermal resources can be added as a contingency for project uncertainty. Removing renewable resources has a reduced impact on LOLE when there are firm thermal resources on the grid.

Probabilistic Analyses – Additional Unit Removals

Green = LOLE ≤ 0.10 Days/Yr (US Mainland), LOLH ≤ 3 hrs (Belgium, France, GB, Poland), EUE ≤ 0.002% of load/20 MWh (AEMO)

Year 2030	Existing Firm (MW)	Firm Removed (MW)	Future Firm (MW)	Planned Variable (MW)	Future Variable (MW)	SA BESS (MW)	LOLE (Days/Yr)	LOLEv (Events/Yr)	LOLH (Hours/Yr)	EUE (GWh/Yr)
Reference Case - 2021	240	-	-	-	-	-	0.15	0.16	**0.25**	**0.00**
Base Case, No ICE	126	-114	0	208.5	82	40	**0.14**	0.31	**0.62**	**0.01**
Add 9 MW ICE	126	-114	9	208.5	82	40	**0.04**	0.07	**0.13**	**0.00**
Add 18 MW ICE, retire M15	113	-127	18	208.5	82	40	**0.04**	0.04	**0.12**	**0.00**
Add 36 MW ICE, retire M15 & M18	100	-140	36	208.5	82	40	**0.02**	0.03	**0.06**	**0.00**
Add 36 MW ICE retire M15 & M18, no Future Variable	100	-140	36	208.5	0	40	**0.03**	0.03	**0.04**	**0.00**

Firm resources can be added as a contingency to meet reliability due to uncertainty in several planned projects and can accelerate removal from service of existing firm units if variable generation targets are reached.

Probabilistic Analyses – Firm/Variable Resource Additions

In 2030, compliance with all three standards is achievable with various resource mixes

- **RESOLVE Base Case, 18 MW Firm Generation Addition Scenario ($214MM)**: 291 MW of variable generation, 40 MW of standalone BESS, and 18 MW of firm generation
  - Variable Generation: 209 MW planned, 82 MW future (includes 60 MW onshore wind)
- **Low Renewable Scenario ($248MM)**: 142 MW of variable generation and 63 MW of firm generation
  - Variable Generation: 60 MW planned (Kuihelani), 82 MW future (includes 60 MW onshore wind)
- **No Firm Addition Scenario ($280MM)**: 328 MW of variable generation
  - Variable Generation: 60 MW planned (Kuihelani), 268 MW future (includes 60 MW onshore wind)

LOLE continues to decrease and reliability improves as more resources are added.

- Removing variable resources has a reduced adverse impact on LOLE when there is a higher capacity of firm thermal resources in the system.
  - Firm thermal resources can be added to the system as a contingency for project or forecast uncertainty.
- There are diminishing returns to LOLE improvement as more resources are added to the system.

Probabilistic Analyses – EUE Heatmap

Base Case with 0 MW Firm Generation

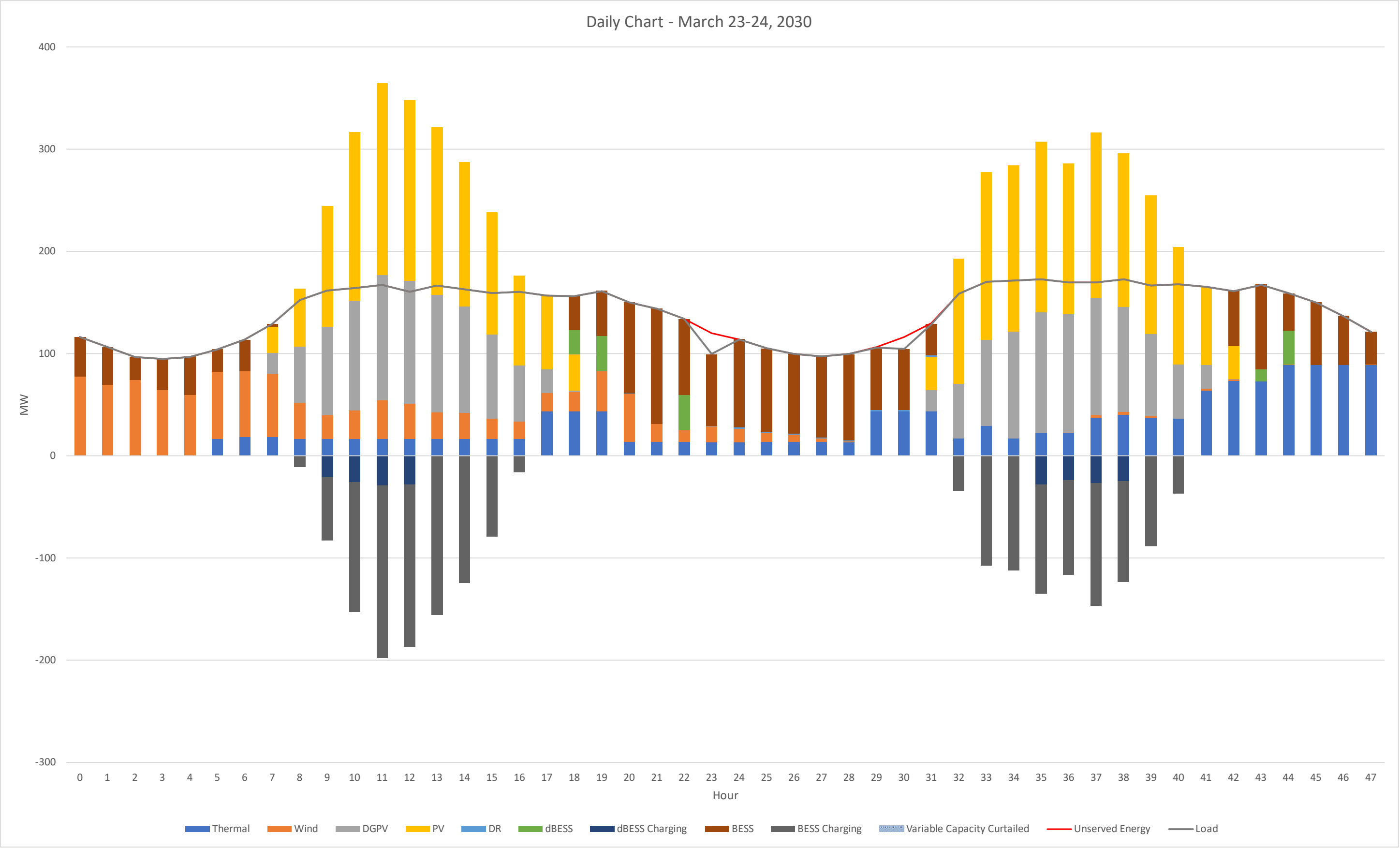
Hours Beginning	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	0.00	0.00	0.00	0.40	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1	0.00	0.00	0.00	0.10	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.07	0.22	0.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.25	0.00	0.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.37	0.32	0.35	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.13	0.25	0.27	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.52	0.22	0.68	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.27	0.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	0.00	0.00	0.00	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	0.00	0.00	0.00	0.18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	0.00	0.00	0.16	0.55	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
18	0.00	0.00	0.13	0.61	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
19	0.00	0.00	0.33	0.83	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
20	0.00	0.00	0.02	0.28	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
21	0.00	0.00	0.09	0.43	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
22	0.00	0.00	0.48	1.30	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.28	0.95	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Base Case with 9 MW Firm Generation

Hours Beginning	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.18	0.06	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.12	0.05	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.02	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.27	0.17	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	0.00	0.00	0.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	0.00	0.00	0.03	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
18	0.00	0.00	0.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
20	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
21	0.00	0.00	0.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
22	0.00	0.00	0.01	0.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.25	0.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Pictured are heatmaps of unserved energy to show likelihood of when unserved energy may occur based on probabilistic resource adequacy analysis. Shortfalls are shown during the months of March, April and May where wind has a lower capacity factor and the PV+BESS do not have enough energy to load shift and meet unserved demand.

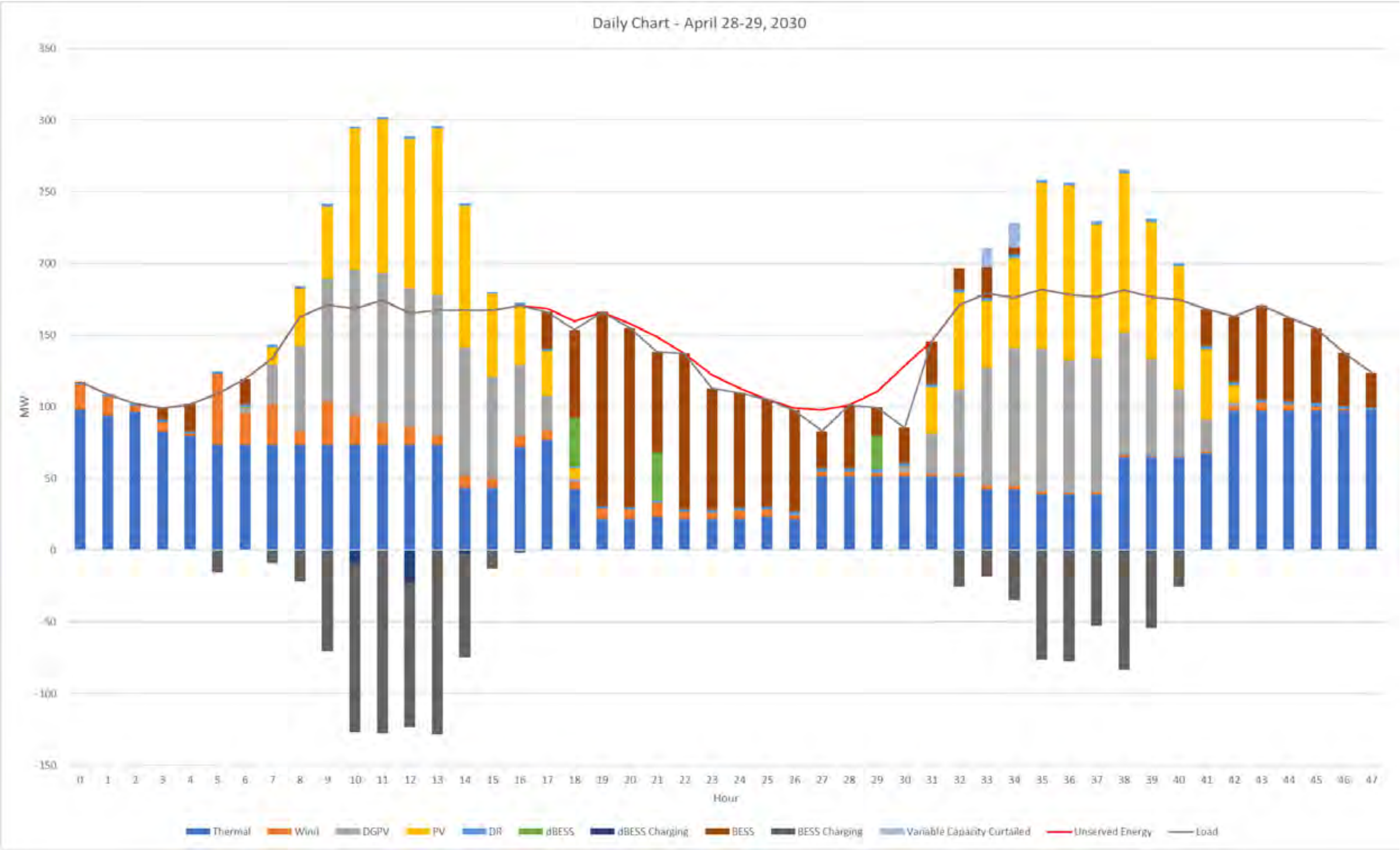
Probabilistic Analyses – Expected Unserved Energy



- The daily chart of the Base Case with 9 MW ICE
- 34 MWh of unserved energy observed late at night and early the next morning, driven by maintenance outages of thermal units.
- All BESS at 100% state of charge (SoC) after hour 17 but there is still not enough energy to serve the load overnight.

ATTACHMENT 2
PAGE 63 OF 70

Probabilistic Analyses – Expected Unserved Energy



- The daily chart of the Base Case with 9 MW ICE
- 105 MWh of unserved energy observed late at night and early the next morning, driven by maintenance outages of thermal units.
- All BESS at 100% SoC after hour 17 but there is still not enough energy to serve the load overnight.

Production Cost Modeling and Operations of the Procurement Plan
Capacity Factor of Firm Units - 18 MW ICE

Year	9 MW ICE Unit 1	9 MW ICE Unit 2	Hana	Kahului1	Kahului2	Kahului3	Kahului4	Maalaea 01	Maalaea 02	Maalaea 03	Maalaea 04	Maalaea 05	Maalaea 06	Maalaea 07
2027	0%	0%	1%	N/A	N/A	N/A	N/A	0%	0%	0%	1%	0%	0%	0%
2028	0%	0%	1%	N/A	N/A	N/A	N/A	0%	0%	0%	2%	0%	0%	0%
2029	0%	0%	1%	N/A	N/A	N/A	N/A	0%	0%	0%	2%	0%	0%	0%
2030	2%	2%	1%	N/A	N/A	N/A	N/A	1%	0%	1%	N/A	N/A	N/A	N/A
2031	6%	6%	1%	N/A	N/A	N/A	N/A	1%	0%	1%	N/A	N/A	N/A	N/A
2032	1%	2%	1%	N/A	N/A	N/A	N/A	1%	0%	1%	N/A	N/A	N/A	N/A
2033	1%	1%	1%	N/A	N/A	N/A	N/A	1%	1%	1%	N/A	N/A	N/A	N/A
2034	2%	2%	1%	N/A	N/A	N/A	N/A	0%	0%	0%	N/A	N/A	N/A	N/A
2035	2%	2%	1%	N/A	N/A	N/A	N/A	1%	0%	1%	N/A	N/A	N/A	N/A

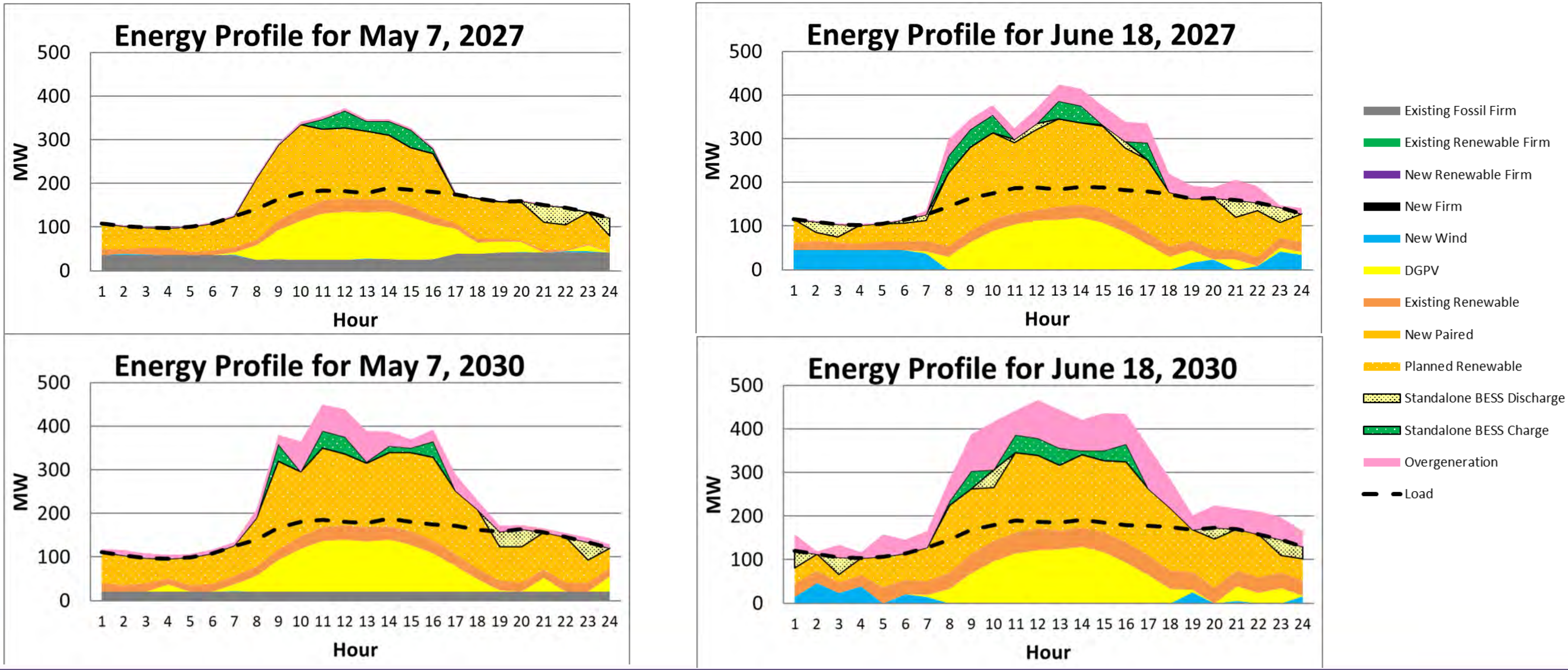
The utilization of new and existing thermal generating units is expected to be low due to the high amounts of variable renewables and storage that are added to the portfolio. The capacity factors shown in these tables support that firm thermal units will primarily act as standby capacity.

Production Cost Modeling and Operations of the Procurement Plan
Capacity Factor of Firm Units - 18 MW ICE

Year	Maalaea 08	Maalaea 09	Maalaea 10	Maalaea 11	Maalaea 12	Maalaea 13	Maalaea X1	Maalaea X2	Maalaea 14cc	Maalaea 15cc	Maalaea 16cc	Maalaea 17cc	Maalaea 18cc	Maalaea 19cc
2027	0%	0%	N/A	N/A	N/A	N/A	0%	0%	41%	55%	38%	6%	0%	0%
2028	0%	0%	N/A	N/A	N/A	N/A	0%	0%	41%	54%	37%	5%	0%	1%
2029	0%	0%	N/A	N/A	N/A	N/A	0%	0%	40%	56%	39%	5%	0%	1%
2030	N/A	N/A	N/A	N/A	N/A	N/A	0%	0%	40%	55%	39%	1%	0%	0%
2031	N/A	N/A	N/A	N/A	N/A	N/A	0%	0%	38%	49%	36%	1%	0%	0%
2032	N/A	N/A	N/A	N/A	N/A	N/A	0%	0%	39%	55%	39%	0%	0%	0%
2033	N/A	N/A	N/A	N/A	N/A	N/A	1%	1%	41%	56%	38%	0%	0%	0%
2034	N/A	N/A	N/A	N/A	N/A	N/A	0%	0%	41%	56%	40%	0%	0%	0%
2035	N/A	N/A	N/A	N/A	N/A	N/A	0%	0%	41%	57%	40%	0%	0%	0%

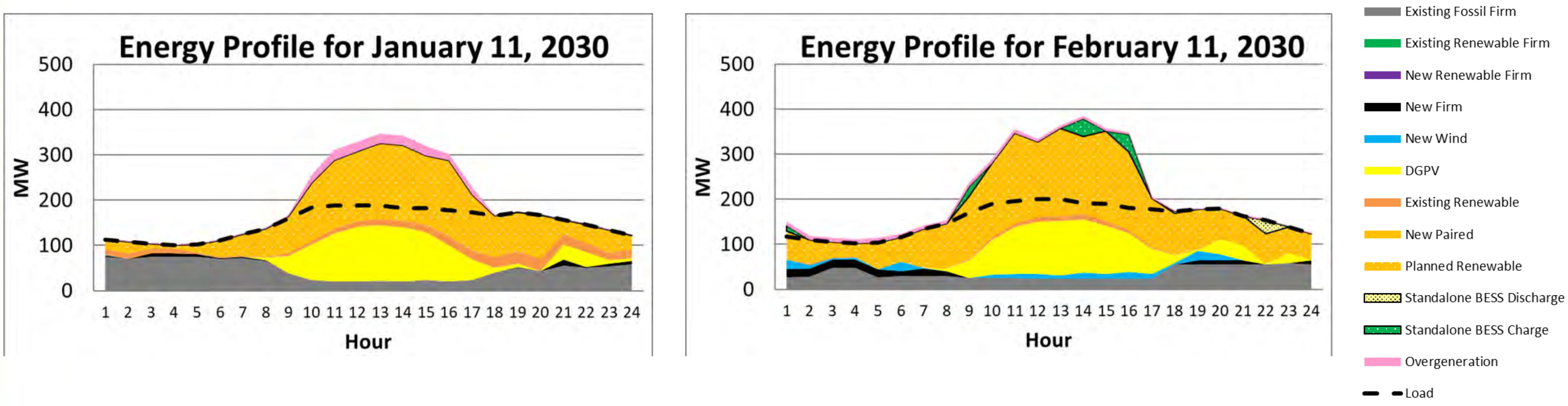
Production Cost Modeling and Operations of the Procurement Plan
Daily Charts - 18 MW ICE

Hourly dispatch of resources in a day



Production Cost Modeling and Operations of the Procurement Plan
Daily Charts - 18 MW ICE

The new ICE additions runs minimally during the peak and overnight, primarily acting as standby generation.



Recommended Actions and Next Steps

Hawaiian Electric

Hawai'i Powered

Recommended Actions and Next Steps

- Continue to displace fossil fuel through acquisition of low cost, low carbon renewable energy, starting with 240 GWh through the Stage 3 RFP in Docket No. 2017-0352
- Continue to pursue customer adoption of DER (i.e., Battery Bonus) through new programs and advanced rate design, consistent with the outcomes of the DER Docket No. 2019-0323
- Pursue generation modernization as soon as practicable to mitigate present reliability risks. Firm renewable generation needs include 18 MW in the near term, starting with the Stage 3 RFP in Docket No. 2017-0352. A total of 40 MW of new firm generation may be prudent to mitigate uncertainty in planned renewable projects that are expected to come into service over the same timeframe
- Pursue development of renewable energy zones to facilitate interconnection of additional renewable energy in collaboration with communities and project partners
- Consider procurement of energy efficiency in amounts up to the forecasted target to reduce supply side needs
- Continue to pursue managed EV charging programs, time-of-use rates, DER, and energy efficiency
- Incorporate system security and system stability analyses, which may yield additional resource needs to mitigate risks associated with a high renewable energy system

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