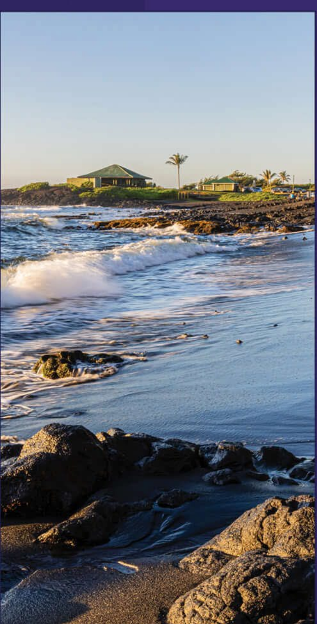
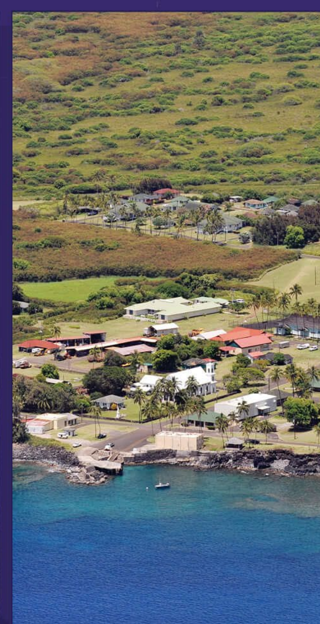
Hawai'i Powered

Integrated Grid Plan

A pathway to a clean energy future




DRAFT

Hawaiian Electric

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Contents

Abbreviations

Abbreviation	Definition
2018$MM	millions of 2018 dollars
AC	alternating current
ADMS	advanced distribution management system
AEG	Applied Energy Group
AMI	advanced metering infrastructure
ARA	Annual Revenue Adjustment
ARD	advanced rate design
ATB	annual technology baseline
BAU	business as usual
BESS	battery energy storage system
C&S	codes and standards
CBRE	community-based renewable energy
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
DC	direct current
DER	distributed energy resources
DOE	U.S. Department of Energy
DRC	Designing Resilience Communities: A Consequence-Based Approach for Grid Investment
eBus	electric bus
ECRC	Energy Cost Recovery Clause
EE	energy efficiency
EIA	U.S. Energy Information Administration
EOI	Expression of Interest
EoT	electrification of transportation
EPRM	Extraordinary Project Recovery Mechanism
ETIPP	Energy Transitions Initiative Partnership Project
EUE	expected unserved energy
EV	electric vehicle
GMLC	Grid Modernization Laboratory Consortium
GWh	gigawatt-hour(s)
HNEI	Hawai'i Natural Energy Institute
ICE	Interruption Cost Estimator
IECC	International Energy Conservation Code
IEEE	Institute of Electrical and Electronics Engineers
IIJA	Infrastructure Investment and Jobs Act
IT	information technology
ITC	Income Tax Credit
km	kilometer(s)
km^2	square kilometer(s)
kV	kilovolt(s)
kW	kilowatt(s)
kWh	kilowatt-hour(s)
LBNL	Lawrence Berkeley National Laboratory

Abbreviation	Definition
LDV	light-duty vehicle
LiDAR	light detection and ranging
LMI	low to moderate income
LOLE	loss of load expectation
LOLEv	loss of load events
LOLH	loss of load hours
MT	metric ton(s)
MVA	megavolt-ampere(s)
MVAR	megavolt-ampere(s) reactive
MW	megawatt(s)
MWh	megawatt-hour(s)
N/A	not applicable
NESC	National Electric Safety Code
NIST	National Institute of Standards and Technology
NOSC	Network Operations and Security Center
NPV	net present value
NREL	National Renewable Energy Laboratory
NWA	non-wires alternative
OT	operational technology
PNNL	Pacific Northwest National Laboratory
POET	Power Outage Economics Tool
PPA	power purchase agreement
PPAC	Purchased Power Adjustment Clause
PV	photovoltaic
RBA	Revenue Balancing Account
RDG	renewable dispatchable generation
ReNCAT	Resilient Node Cluster Analysis Tool
Report	Performance Metrics to Evaluate Utility Resilience Investments
REZ	renewable energy zone
RFP	request for proposals
RPS	renewable portfolio standards
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SANDIA	Sandia National Laboratory
SLH	Session Laws of Hawai'i
SLR-XA	sea-level rise exposure area
STATCOM	STATic synchronous COMpensator
State	State of Hawai'i
STEM	science, technology, engineering, and mathematics
T&D	transmission and distribution
TOU	time of use
VAR	voltage-ampere reactive
WIND	Wind Integration National Dataset
ZEV	zero-emission vehicle

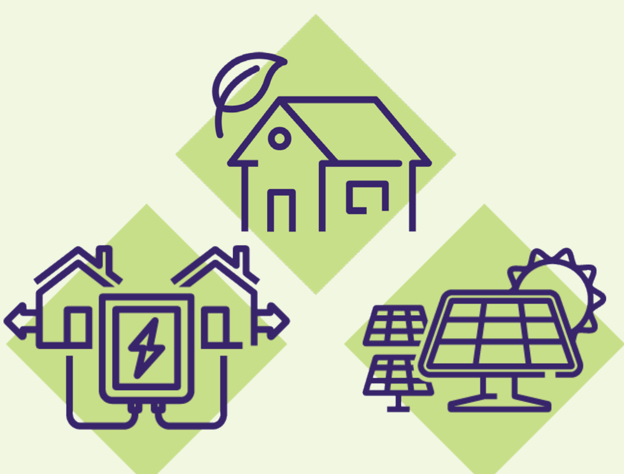
Glossary

Term	Definition
Battery energy storage	A form of chemical storage that is able to store energy for use at another time. For example, a battery energy storage system can charge using solar energy during the day and discharge that energy for use at night.
Decarbonization	To reduce, offset, or eliminate all carbon-producing sources contributing to climate change. Decarbonization is a comprehensive approach to climate resilience that considers all sources of carbon emissions, including electricity generation, transportation, shipping, waste management, agriculture, manufacturing, and land management.
Distributed energy resources	Refers to a behind-the-meter technology or device that can alter a customer's energy use. These technologies include rooftop solar, battery storage, electric vehicles, controllable devices (i.e., grid-interactive water heaters) and energy efficiency. However, in this report it most often refers to rooftop solar and/or battery energy storage located behind a customer's meter.
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.
Flexible generation	Power plants that can start up, ramp up and down quickly and efficiently, and run at low output levels.
Grid needs	The specific grid services (including but not limited to capacity, energy and ancillary services) identified through analysis, including transmission and distribution system needs.
Harden	In the context of this report, generally refers to installation of grid infrastructure equipment designed and built to be more resistant to severe events.
Hybrid solar	A solar system (typically referred to in the large-scale context) that uses photovoltaic technology and is paired with battery energy storage, with a typical duration of 4 hours.
Microgrid	A microgrid generates, distributes, and regulates the supply of electricity to customers on a smaller, local scale compared to traditional, centralized grids. Microgrids are a group of interconnected loads and distributed energy resources within clearly defined boundaries. It is normally interconnected to the grid and can disconnect from the grid during emergencies. They are best suited to areas near critical infrastructure (such as hospitals and emergency response centers), have access to renewable energy resources, and are prone to prolonged outages during weather events.
Net present value	The value of a future dollar amount that accounts for the time value of money.
Photovoltaic	Commonly known as solar panels, this technology generates power by absorbing energy from sunlight and converting it into electrical energy.
RESOLVE	A resource investment model developed by E3 that identifies optimal long-term generation investments in an electric system, subject to reliability, technical, and policy constraints.
Resource 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.

1. Executive Summary

Hawaiian Electric and our customers are rapidly transforming the ways we generate, transmit, and use electricity. Together, we are creating a resilient clean energy grid powered by resources from Hawaiʻi, for Hawaiʻi. By 2045, our energy system will use 100% renewable resources and produce net-zero carbon emissions, meaning whatever small amount of emissions we emit will be captured or offset. Our work to modernize and decarbonize the grid has never been more urgent as the effects of climate change escalate and existing electrical facilities and infrastructure age. The world is watching as we innovate to scale up clean energy on islands with abundant resources but no option to import renewables from neighbors.

We envision a clean energy future where customers have more choices, more reliable power, and more stable rates. By 2045, clean energy will be there when we need it: behind every light we turn on, each meal we share, and all the ways we get around. Electric cars and buses will get us where we need to go, with a backbone of vehicle chargers at the workplace and community centers. At home and at work, energy-efficient appliances and equipment will electrify our daily lives.



This clean energy transformation will advance social equity and benefit all customers and communities. Enhanced grid capacity will support growth in residential and commercial development, empowering a statewide expansion in affordable housing. In places with new energy facilities, host communities will thrive with benefit packages from developers.

The future grid will look unlike any before, with customers playing a vital role in generating and storing energy. Customer-scale generation and battery storage in customers' homes and communities will seamlessly connect to large-scale generation through a modernized transmission system, providing a consistent stream of energy that can adapt to fluctuations in use. Sourcing energy from a diverse array of local, renewable resources will fortify Hawaiʻi against global swings in oil prices, stabilizing utility costs for customers.

How can we bring this vision to life?

It is possible to live out this vision if we work together and act now.

Hawaiian Electric is pleased to present the Integrated Grid Plan: a pathway to a clean energy future. The Integrated Grid Plan proposes actionable steps to decarbonize the electric grid on the State of Hawai'i's (State's) timeline, with a flexible framework that can adapt to future technologies.

The Integrated Grid Plan is the culmination of more than 5 years of partnership with stakeholders and community members across the islands. Together, we forecasted future energy needs and identified strategies to meet Hawai'i's growing energy demand with 100% renewable resources. Hawaiian Electric is grateful for the collective time, efforts, and insights of the many people involved in Integrated Grid Planning, and we look forward to continued collaboration with customers, community members, and stakeholders as we move beyond planning into implementation.

This report shares our action plan and summaries of the technical analyses and community engagement. It also underscores the urgency of action needed to achieve this future. We hope the findings help drive or supplement other action plans beyond Hawaiian Electric. The Integrated Grid Plan shows that every industry and individual will need to play a role in decarbonizing Hawai'i's economy. This plan can help customers, organizations, and agencies understand the scope of the challenge and their role in meeting it. It's everyone's kuleana to create a sustainable future for Hawai'i.

The Integrated Grid Plan is an important starting point for focusing efforts and measuring progress. Now, it's time to take collective action to create a Hawai'i Powered future where everyone will thrive.

1.1 Customers Are at the Heart of the Energy Transformation

Again and again throughout the planning process, we heard that affordability and reliability are of top concern and interest to our customers, echoing the comments in multiple customer surveys and focus groups conducted for the company.

It is imperative that our future grid delivers on this fundamental need for pricing and power that people can count on.

The Integrated Grid Plan balances our commitment to clean energy with our commitment to stabilizing rates and improving reliability for customers.

The Integrated Grid Plan also shows that ***customer and community participation is essential to decarbonizing Hawai'i's economy.*** Our analysis reveals that we cannot meet projected demands on the grid without customers and communities generating and storing energy and practicing greater energy efficiency (EE). Read more about the role of customers in Section 1.5.2.

Meaningful and sustained engagement with customers, communities, and stakeholders has been central to Integrated Grid Planning. Since planning began in 2018, we have worked to foster partnerships with communities that we are a part of and serve by sharing transparent information and listening, learning, and incorporating their feedback. We are grateful for the involvement of thousands of community members throughout the planning process, and we appreciate the opportunities we have had to collaborate on potential solutions. See Section 4 for more information about outreach activities and how we have incorporated public input.

1.2 Our Commitment to Customers

At Hawaiian Electric, customers are at the heart of our work today and our vision for the future. We are deeply rooted in our communities, and we strive to serve the energy needs of each person in Hawaiʻi with purpose, compassion, empathy, and aloha for our fellow humans and our natural environment. We are committed to empowering our customers and communities with affordable and reliable clean energy, and providing innovative energy leadership for Hawaiʻi.

1.2.1 Climate Change Action Plan

Decarbonizing the electric grid is ultimately about service: caring for our customers and the environment by creating a more prosperous and sustainable Hawaiʻi. To that end, Hawaiian Electric announced a bold Climate Change Action Plan in 2021. Our Climate Change Action Plan sets the ambitious goal of reducing electricity-sector greenhouse gas emissions in 2030 by as much as 70% compared to 2005 levels and reaching net-zero carbon emissions by 2045.

DECARBONIZE:

> To reduce, offset, or eliminate all carbon-producing sources contributing to climate change. Decarbonization is a comprehensive approach to climate resilience that considers all sources of carbon emissions, including electricity generation, transportation, shipping, waste management, agriculture, manufacturing, and land management.

This commitment by Hawaiian Electric represents a significant down payment on the economy-wide reduction Hawaiʻi will have to achieve to align with nationwide and global greenhouse gas reduction goals. Statewide decarbonization will require collaboration across sectors, with transportation, agriculture, and other industries working to reduce and offset emissions.

1.2.2 Hawaiʻi Powered

A key strategy to reaching net-zero emissions is generating 100% of our energy from renewable resources. In 2015, Hawaiʻi became the first state in the nation to direct its utilities to generate 100% of their electricity from renewable energy sources by 2045. Hawaiian Electric is dedicated to partnering with customers, communities, and other stakeholders to reach this energy goal.

Hawaiʻi Powered

We call our vision for using 100% renewable resources "Hawaiʻi Powered." Clean energy for Hawaiʻi, by Hawaiʻi:

- Supports our Climate Change Action Plan and the State's decarbonization goals
- Achieves energy independence
- Expands energy choices for customers and helps stabilize rates

1.2.3 Ensuring an Equitable Energy Transformation

We are committed to creating an equitable energy future. As the cost of living in Hawaiʻi continues to rise, we must make electricity affordable and ensure that we ease the burden of the renewable transition on customers with low to moderate income (LMI). We must also ensure that communities that bear the burden of hosting energy infrastructure, both in the past and future, receive benefits.

The Public Utilities Commission recently opened a proceeding to investigate energy equity in response to legislative resolutions. The areas for exploration include:

- High energy rates in Hawaiʻi
- High percentage of people with low and moderate income
- High energy burden
- Lack of universal access to renewable energy initiatives
- Need for utility payment assistance
- Historical siting of fossil-fuel infrastructure
- Land constraints
- Regulatory process burdens

The benefits and burdens of the transformation to a clean energy grid must be equitably shared. All customers stand to benefit if everyone is able to afford electricity and participate in the transition. See Section 10 for more information about our ongoing efforts to address energy inequities and offer solutions for the future.

We use the following definitions from the Public Utility Commission to guide planning for energy equity:

Equity refers to achieved results where advantages and disadvantages are not distributed on the basis of social identities. Strategies that produce equity must be targeted to address the unequal needs, conditions, and positions of people and communities that are created by institutional and structural barriers.

Energy equity refers to the goal of achieving equity in both the social and economic participation in the energy system, while also remediating social, economic, and health burdens on those historically harmed by the energy system.

People with low to moderate income are those whose income is at or below 150% of the Hawaiʻi federal poverty limit.

Energy burden is the percentage of a household's income spent to cover energy costs.

1.3 Renewable Energy and Reliability Risks Today

Hawaiian Electric has the privilege of serving as Hawai'i's largest electric utility. We serve 95% of Hawai'i's 1.4 million residents on the islands of Hawai'i, O'ahu, Maui, Lāna'i, and Moloka'i, each with separate grids. Since 2010, we have nearly tripled the amount of renewable energy we generate, due in large part to the contributions of our customers. We are proud of the progress we have made, but we still have a long way to go.

1.3.1 Our Current Renewable Energy Portfolio

Today, approximately 32% of our total energy generation comes from renewables. Our renewable energy comes from many local sources with wide-ranging technologies, and each island has a unique composition of clean energy generation. Figure 1-1 shows the 2022 composition of clean energy generation on Hawai'i Island, O'ahu, and Maui, and the consolidated proportions across all three.

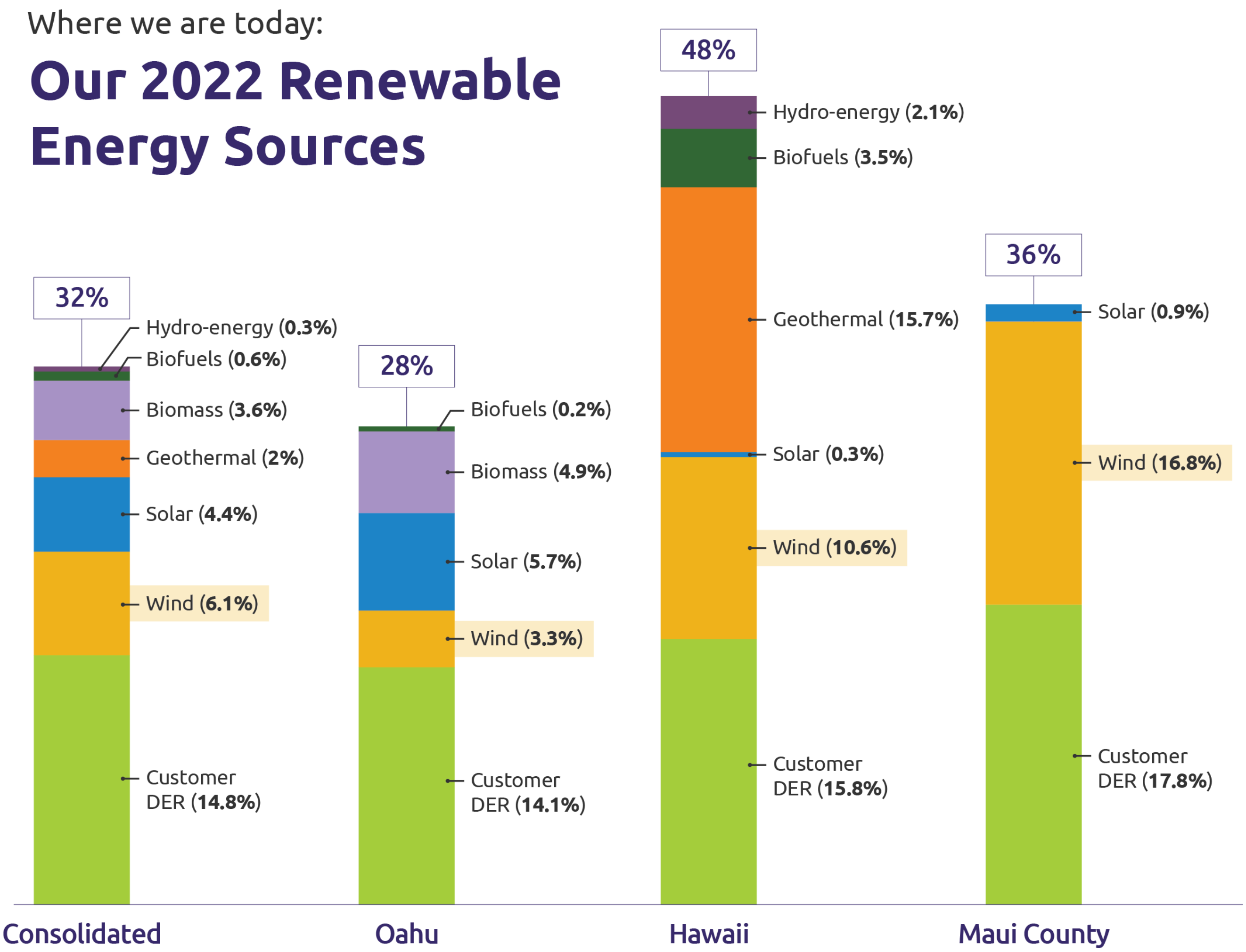


Figure 1-1. Renewable energy portfolios, 2022

1.3.2 Immediate Action to Meet Goals and Maintain Reliability

Creating a resilient, clean energy grid has never been more urgent as the effects of climate change escalate, existing energy infrastructure ages, and our timelines shrink. Customers are at risk of experiencing increasingly frequent outages unless we take immediate action to address threats to reliability.

We must act now to bolster the reliability of our electric grid and prevent significant economic and social disruption for customers. Investing in renewable energy generation and updates to transmission infrastructure is an opportunity to address these risks. See Section 7 and Section 12 for more information about investments and actions to reduce risks to electrical infrastructure.

We must move swiftly to:

Fortify the grid against extreme weather.

Extreme weather hazards are projected to increase in frequency, intensity, and duration because of climate change. Failure to prepare for such events could result in power interruptions, damage to electricity infrastructure, significant economic disruption, and disruption to critical government and private-sector services. Reliability is a matter of safety and state and national security, as our critical infrastructure—like hospitals, communication systems, and emergency services—depends on electricity.

Meet growing energy demands.

Existing fossil-fuel generators on Hawai'i Island, Maui, and O'ahu are 55 to 75 years old. These facilities were never designed to keep up with today's dynamic grid, which far outpace the needs of decades past and continue to grow. We anticipate that the demand for electricity will dramatically increase in the coming years, as other sectors reduce their carbon emissions, and as customers and businesses use more electricity for their transportation, work, and homes. We're in urgent need of more generation capacity to meet this demand.

Cut carbon emissions by 70% in 7 years.

2030 is just around the corner. We need to rapidly develop energy projects and the necessary infrastructure across the islands to meet our Climate Change Action Plan goal of cutting emissions by 70% (compared to 2005 levels). This will take efficient and effective coordination with communities, policymakers, stakeholders, and developers to bring renewables online as we deactivate fossil-fuel generators. Simply put: there's no time to waste.

1.4 Overview of Integrated Grid Planning

Integrated Grid Planning brought many people together to determine how to create a resilient and reliable grid that will meet future energy needs, stabilize costs for customers, and use 100% renewable resources. Hawaiian Electric began the planning process in 2018. Figure 1-2 displays the steps of Integrated Grid Planning.

Figure 1-2. High-level steps of Integrated Grid Planning

1.4.1 Engaging Communities and Stakeholders

We engaged four main stakeholder groups throughout the planning process:

The four main stakeholder groups:

Stakeholder Council. This group consisted of representatives from cities, counties, each island, the State, partner agencies, and developers. It helped align our planning with interests across the islands.

Working Groups. These specialized groups served in an advisory capacity and were focused on topics like social and economic resilience, transmission planning, and the sourcing and evaluation of contractors.

Technical Advisory Panel. This group consisted of experts in energy technologies and engineering who provided an independent source of peer assessment.

The public, including customers and community members across the islands.

The four Integrated Grid Planning stakeholder groups were not working alone—many others have been and continue to be involved in creating a clean energy future. These groups include policymakers, regulators, developers, and community organizations.

1.4.2 Key Considerations

Stakeholders helped us prioritize and connect five key considerations that shape our planning for a clean energy future:

- **Time.** How much time will it take to deliver new energy facilities, and how can we stay on track with our timeline goals?
- **Affordability.** How much will it cost to build and operate? What will resources cost in the future? How will costs affect customer bills?
- **Land use.** Where is there available land? How does this affect other land use priorities?
- **Community impacts.** How will new facilities affect surrounding communities, jobs, and the environment? How can the benefits of the transition to clean energy be equitably shared?
- **Resilience and reliability.** How can we plan for current and future energy needs? Needs evolve based on the number of electric vehicles (EVs), number of private and community-based solar projects, emerging technologies and industries, and preparation for extreme events.

Understanding energy needs of today and tomorrow required many technical analyses and input from stakeholders and community members. Together, we forecasted future energy needs and identified opportunities to meet growing demands.

See Sections 6 and 8 for information about the data and models we used to forecast grid needs. See Section 4 for an overview of outreach strategies and community input we received about potential future energy projects and key considerations.

1.4.3 Guiding Principles

The following principles guided our technical analyses and community conversations as we moved through Integrated Grid Planning.

1 ***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 Hawai'i 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.

2 ***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 LMI households. Meaningful community participation must be a key element of renewable project planning.

3 ***The lights have to stay on.*** Reliability and resilience of service and quality of power are vital for our economy, national security, and critical 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.

4 ***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.

5 ***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 (EoT).

6 ***Our plans must address climate change.*** Our Climate Change Action Plan set a goal to reduce carbon emissions from power generation by 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.

7 ***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, policymakers, and other stakeholders.

1.4.4 Energy Planning on Molokaʻi and Lānaʻi

We tailored our planning and community engagement strategies to each island, recognizing that they have unique energy needs and opportunities. Planning for a clean energy future on Lānaʻi and Molokaʻi was particularly distinct for the following reasons.

Lānaʻi

Much of our grid planning work on Lānaʻi happened in collaboration with the majority landowner on the island. The Hawaiian Electric team recently announced its selection of a developer to build and maintain the island's largest renewable energy project and the first to offer the Shared Solar program on the island. We completed contract negotiations with DG Development & Acquisition, LLC. However, we have not finalized the contract as the majority landowner, Pūlama Lānaʻi notified Hawaiian Electric of its intent to design and construct microgrids to supply the energy demands of the resorts on Lānaʻi, which would significantly impact the electric load and the size of the solar project.

Molokaʻi

Molokaʻi is preparing a Molokaʻi Community Energy Resilience Action Plan: an independent, island-wide, community-led and expert-informed collaborative planning process to increase renewable energy on the island. The Molokaʻi Clean Energy Hui by Sustʻāinable Molokaʻi is coordinating the action plan. Hawaiian Electric is providing technical support to the Molokaʻi Clean Energy Hui in its planning process to develop a portfolio of clean energy projects to achieve 100% renewable energy for the island that is feasible, respectful of Molokaʻi's culture and environment, and strongly supported by the community. Learn more at sustainablemolokai.org/renewable-energy/molokai-cerap.

Hawaiian Electric and Hoʻāhu Energy Cooperative Molokaʻi are moving ahead with the State's first two community-owned and -designed solar plus battery projects. These projects could meet more than 20% of Molokaʻi's energy needs and serve an estimated 1,500 households on the island. The Hoʻāhu Community-Based Renewable Energy (CBRE) projects, Pālāʻau Solar and Kualapuʻu Solar, will be the first on the island to offer the Shared Solar program to help lower the electric bills of customers on Molokaʻi who are unable to install privately owned rooftop solar.

After the completion of a competitive bidding evaluation process, which accounted for the cost of the projects as well as non-price factors including community outreach, Hoʻāhu and Hawaiian Electric entered into negotiations. Once negotiations of the 20-year contracts are finalized, Hawaiian Electric and Hoʻāhu will submit the two applications for approval by the Public Utilities Commission.

1.5 Action Plan at a Glance

Meeting the energy needs of our customers up to and beyond 2045 requires an Integrated Grid Plan based on a short-term action plan and a long-term strategy. First, the Integrated Grid Plan requires us to take immediate action within the next 5 years to achieve our 2030 goals and set a path toward 2045 decarbonization. The proposed 5-year action plan identifies the next foundational steps toward meeting our decarbonization, affordability, and reliability goals for customers. Second, the Integrated Grid Plan also provides the flexibility we need over the long term to realize the benefits of technological advances, respond to changing customer and community needs, and adapt to evolving environmental conditions.

The following is an overview of the Integrated Grid Plan key findings and recommended actions for the short term. See Section 2 for details.

1.5.1 Key Findings and Recommendations

The Integrated Grid Plan points to four high-level actions we must take within the next 5 years to reach statewide decarbonization goals and future energy needs:

Stabilize utility rates and advance energy equity

Grow the marketplace for customer-scale and large-scale renewables

Create a modern and resilient grid

Secure reliability through diverse energy sources and technologies

The following is an overview of these actions. See Section 2 for details.

1.5.2 Action Plan for a Clean Energy Future

Stabilize rates and advance energy equity

Although utility rates will rise in the transition to clean energy, they will be lower and less volatile than if we continue to rely on fossil fuels. Our projections show that customer bills may remain relatively flat, despite growing demands for electricity, integration of renewables, and investments to modernize and strengthen the grid. The addition of customer-scale and large-scale renewable energy is expected to stabilize rates and insulate all customers from volatile fossil-fuel markets. Additionally, the electrification of transportation may drive benefits for all customers by putting downward pressure on rates. Increased electrification of transportation enables the cost of grid investments to be spread over more kilowatt-hours (kWh), reducing per-unit customer costs and introducing opportunities to provide grid services. See Section 9 for more information about impacts to customer bills and the environment.

We are committed to an equitable energy transition that addresses the total energy burden on low- and moderate-income customers.

To that end, the Integrated Grid Plan may help to inform the Energy Equity proceeding that aims to examine forms of relief for LMI customers. Our projections show that the transition to clean energy may reduce the overall energy burden for the typical residential customer on each island through 2050, compared to today's energy burden. See Section 10.3 for more information about affordability and the energy burden.

Grow the marketplace for customer-scale and large-scale renewables

We will need a marketplace for both customer-scale and large-scale renewables to achieve 100% clean energy by 2045. To grow the market for large-scale projects that also benefit host communities, we propose routine cyclical procurements with public input and community benefit packages from developers.

We also propose customer programs and options with incentives to increase customer participation in energy efficiency, rooftop solar, energy storage, and vehicle charging. Customer participation and early community outreach are instrumental to electrifying and decarbonizing the state's economy. Customer-scale generation is also an opportunity to promote energy equity by continuing to develop programs that expand access to a wider range of customers. Programs like Shared Solar (CBRE) are essential for all customers to benefit from generating renewable energy, not only those who own their homes and rooftop solar systems. See Section 11 for more information about customer programs and large-scale procurements.

The Integrated Grid Plan will benefit the environment by reducing carbon emissions by 75% by 2030, relative to 2005 levels. However, achieving net zero will depend on technology advancements.

We forecast that energy generation and storage by customers and communities can provide enough electricity to power the transition to electric vehicles, and it will also reduce the amount of land needed for large-scale renewables.

Create a modern and resilient grid

Renewable generation is just one piece of the energy transformation puzzle. We will also need a modern, resilient system of transmission and distribution (T&D) for customers to power their electric vehicles, connect rooftop solar systems and large-scale renewable generation hubs, support the expansion of affordable housing, and fortify the grid against extreme weather events. This will require investment in distribution, transmission, and grid hardening.

The State's economic and policy goals include developing new housing and commercial development to expand our economy while addressing equity. These homes and businesses will be electrified with clean energy, increasing net demand on the grid. To support this effort, we estimate that over the next 10 years, up to $59.4 million of distribution upgrades and $1.33 billion in renewable energy zone (REZ) enablement and transmission network upgrades are needed.

We will be actively pursuing the opportunity to partner with our customers to shape energy use.

Secure reliability through diverse energy sources and technologies

A diverse grid is a reliable grid. We propose investing in many different resources at various scales, including large-scale renewable and firm generation to replace aging fossil fuel–based generators. A fleet of large-scale renewable and firm generation will ensure that we have a source of stable, consistent power on standby to supplement smaller-scale generation on customers' homes and communities, as well as weather-dependent resources like solar and wind.

The sooner we modernize the generation portfolio with the right types of resources, the sooner we can retire or deactivate our older fossil-fuel plants.

LARGE-SCALE RENEWABLE GENERATION:

Large-scale generation facilities and transmission infrastructure produce and carry a large volume of energy. This includes wind turbines and solar and battery energy storage facilities, as well as electric substations, poles and wires.

FIRM GENERATION:

Firm generation provides a steady, reliable flow of energy because it uses resources that are not weather-dependent. Examples of firm generation are geothermal, waste-to-energy, and green hydrogen.

1.5.3 Timeline of Renewable Energy Procurement

The Integrated Grid Plan outlines the amount of energy generation we will need to procure to meet statewide decarbonization goals. Figure 1-3 displays a high-level timeline of adding renewable generation capacity, retiring fossil fuel–based generation, and reducing carbon emissions. Figure 1-4 shows our Integrated Grid Plan's renewable energy portfolio.

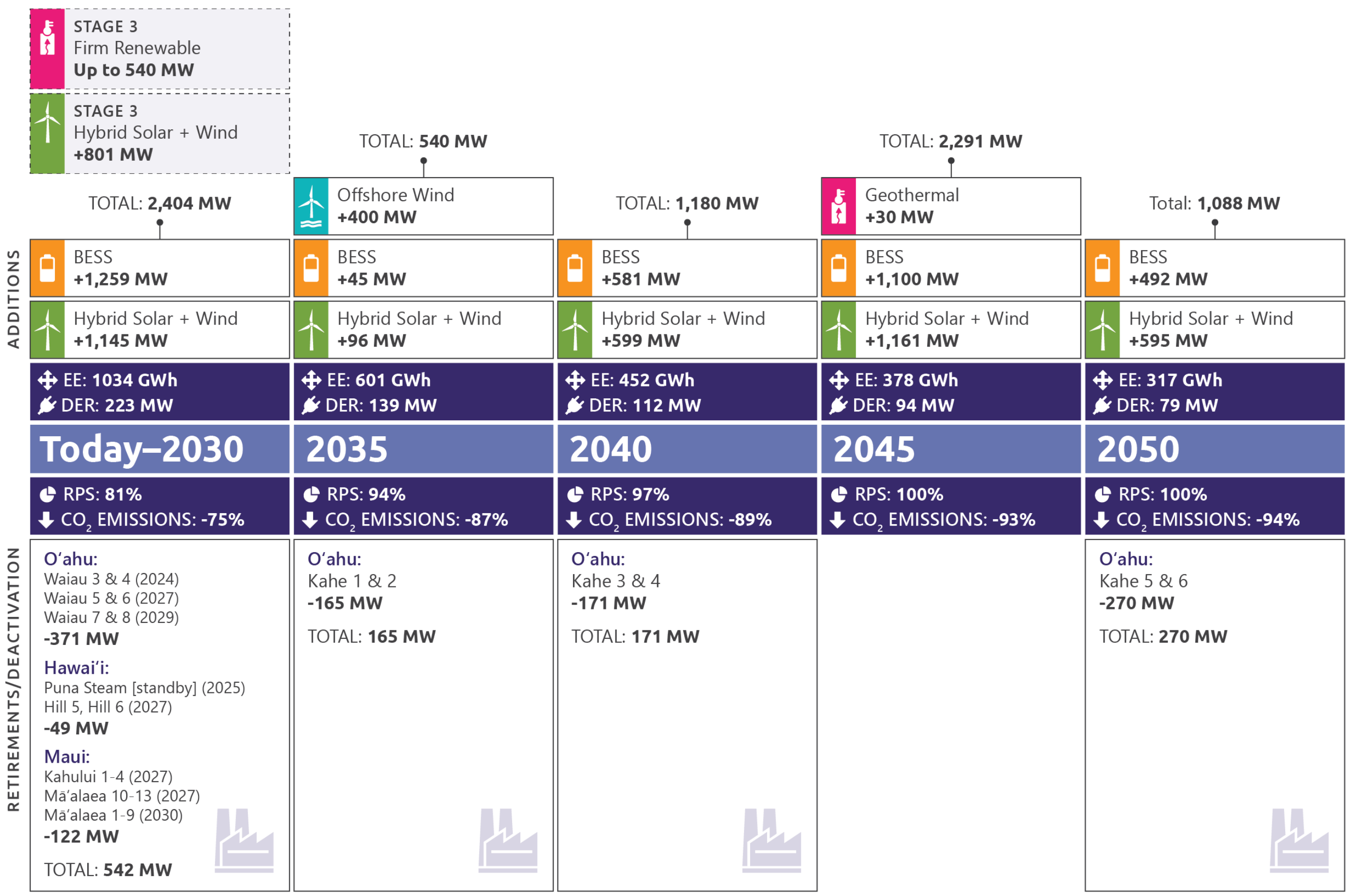


Figure 1-3. Proposed timeline of adding renewable resources, retiring or deactivating fossil fuel–based generation, and reducing carbon emissions

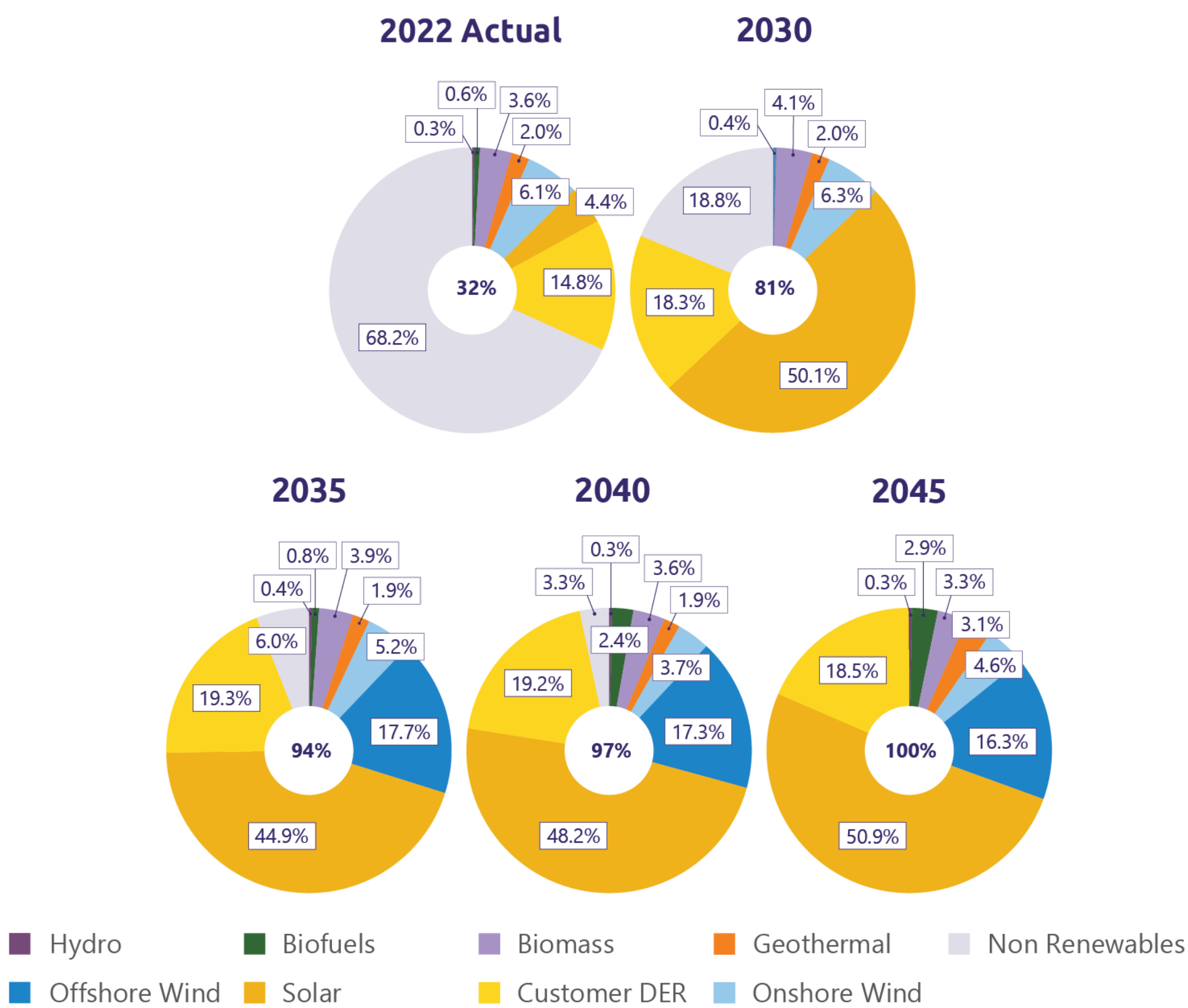


Figure 1-4. Consolidated RPS from today through 2045

Why is rooftop solar not enough?

We need a mix of customer-scale and large-scale renewable generation to supply enough power to meet future energy demands. As much as we value rooftop solar, it is not enough on its own to power the whole grid.

- **A diverse power system is resilient.** Generating electricity from a diverse portfolio of resources benefits our overall energy resilience and customer bills. Diversifying our energy generation to include customer-scale customer and community resources and large-scale renewables (including sources beyond solar) keeps us from depending on any one source for our electricity. This helps us bounce back faster from disasters and shields us from fluctuating costs of resources. For customers, this means reduced risk of outages and more stable utility bills.
- **We need customer-scale and large-scale resources to meet Hawai'i's energy needs.** As much as we value rooftop solar and distributed storage, they are not enough on their own to power the whole grid. This is especially true in a clean, electrified future. For example, to replace just one fossil-fuel generator on O'ahu, we estimate needing new wind and solar resources with a collective footprint 29 times the size of Aloha Stadium. Customer adoption of rooftop solar is not projected to reach the level and reliability to meet all customers' electricity needs. New, large-scale renewable resources will be a significant part of a Hawaii Powered future.
- **Clean energy must be affordable and equitable for all customers.** Electricity affordability is a critical factor to achieve Hawai'i's decarbonization goals. This requires careful consideration of energy equity and the cost-effectiveness of our collective customer, community and large-scale renewable resources and storage options. Each of these resource and storage options have benefits and challenges that need to be assessed. No single renewable technology solution addresses all of Hawai'i's needs. We need to develop a diversified renewable portfolio that is affordable, equitable, and reliable for all customers.

1.6 Moving beyond Planning into Action

Energy planning does not exist in isolation—it's interconnected with many other aspects of life and public policies. It is therefore imperative that any long-term plans for Hawai'i's energy future balance multiple State policy objectives, including affordable housing, food sustainability, land use, and economic development. Effectively implementing the Integrated Grid Plan will depend on:

- Enhanced energy policies and alignment with other State policy objectives
- Streamlined regulatory and county and State process
- Public, stakeholder, and community partnership
- Actions outside of and beyond Hawaiian Electric

None of us can implement the Integrated Grid Plan alone. It will take continued collaboration of customers, communities, utilities, counties, the State, and other industries to meet decarbonization goals and live out a resilient clean energy future.

The longevity of our beloved islands for future generations depends on our ability to come together, get creative, and get to work creating a more sustainable Hawai'i.

The time for action is now.

2. Action Plan

Our **action plan** focuses on efficient strategies to swiftly decarbonize the electric grid and manage risks to affordability, resilience, and reliability. We find that cutting carbon emissions by 70% by 2030 is possible through an "all of the above" approach that seeks to expand customer participation and large-scale generation and infrastructure. Establishing a competitive energy marketplace for both customer-scale and large-scale renewables underpins our ability to create an affordable transition. This will take a statewide effort that involves government, communities, and industry partners. We also describe conditions and policies that we need to successfully meet statewide decarbonization goals, and we recommend next steps to move beyond planning into implementation.

2.1 Key Findings and Recommendations

The Integrated Grid Plan points to four high-level actions we must take within the next 5 years to decarbonize the grid while ensuring reliable power and stable rates for customers:

- Stabilize utility rates and advance energy equity
- Grow the marketplace for customer-scale and large-scale renewables
- Create a modern and resilient grid
- Secure reliability through diverse energy sources and technologies

2.1.1 Stabilize Utility Rates and Advance Energy Equity

It is imperative that our future grid delivers on the fundamental need for pricing and power that people can count on. Although utility rates will rise in the transition to clean energy, they will be lower than if we continue to rely on fossil fuels. We are committed to an equitable energy transition that benefits all customers and communities. *To stabilize rates and advance energy equity, we will need to:*

Pursue the least costly pathway, which maximizes solar, wind, and energy storage. We can stabilize rates and mitigate uncertainties in volatile fossil-fuel pricing by acquiring solar, wind, and energy storage through fixed-price contracts. These contracts will provide predictable rates for 20 years or more.

Provide at least $3,000 per megawatt in community benefits packages per year to host communities of large-scale projects. It's essential that all communities benefit from the transition to clean energy. We propose that developers of new renewable generation provide at least $3,000 per megawatt (MW) per year in community benefits packages to the communities that bear the burden of those energy projects and infrastructure. By 2035, our plan calls for up to 1,640 MW of new renewable resources across our service territories.

Keep rates lower than the status quo of fossil-fuel reliance. Although utility rates will rise in the transition to clean energy, they will be lower and less volatile than if we continue to rely on fossil fuels. Our projections show that customer bills may remain relatively flat, despite growing demands for electricity, integration of renewables, and investments to modernize and strengthen the grid. The addition of customer-scale and large-scale renewable energy is expected to stabilize rates and insulate all customers from volatile fossil-fuel markets. Additionally, the electrification of transportation may drive benefits for all customers by putting downward pressure on rates. Increased electrification of transportation enables the cost of grid investments to be spread over more kilowatt-hours, reducing per-unit customer costs and introducing opportunities to provide grid services. See Section 9 for more information about impacts to customer bills and the environment.

Examine forms of relief for LMI customers. We are committed to an equitable energy transition that addresses the total energy burden on LMI customers. Our projections show that the transition to clean energy may reduce the overall energy burden for the typical residential customer on each island through 2050, compared to today's energy burden. See Section 10.3 for more information about affordability and the energy burden.

Pursue federal funding to expand customer access to renewable technologies and reduce the cost of grid modernization. We must expand access to available federal incentives for customer technologies such as energy efficiency. We also have been encouraged by the U.S. Department of Energy (DOE) to submit funding requests with up to a 50% match to implement our Climate Adaptation Transmission and Distribution Resilience program to harden grid infrastructure and for Phase 2 of our grid modernization program.

Actions we can take to stabilize rates within the next 5 years:

- Use competitive procurements to the extent possible for all types of renewable generation as a means to attract lowest pricing possible for customers
- Pursue federal funding with up to 50% match for climate adaptation program and Phase 2 grid modernization
- Work with stakeholders to address affordability through the Energy Equity docket

2.1.2 Grow the Marketplace for Customer-scale and Large-scale Renewable Generation

We will need a lot more renewable energy to electrify Hawai'i's economy and transportation system by 2045. As we retire fossil fuel–based generation, that volume of energy will come from two primary sources: customer-scale renewable generation and large-scale renewable generation. We must support customers in adopting energy conservation measures, installing rooftop solar and battery storage, and we must also rapidly develop large-scale generation facilities. *To grow a thriving, competitive marketplace for these two types of generation, we will need:*

Greater customer participation in energy generation and storage. Customer adoption of private rooftop solar and energy storage is needed to meet the State's 2030 and 2045 decarbonization goals. By 2030, we will need more than 125,000 residential and commercial private rooftop solar and energy storage systems (1,186 MW) across our service territories. These customer resources, along with energy efficiency will help to offset the energy and capacity needed to power electrification of light-duty vehicles (LDVs), reducing land requirements for large-scale resources.

Customer-scale generation is also an opportunity to promote energy equity by continuing to develop programs that expand access to a wider range of customers. Programs like Shared Solar (CBRE) are essential for all customers to benefit from generating renewable energy, not only those who own their homes and rooftop solar systems. See Section 11 for more information about customer programs and large-scale procurements.

Widespread adoption of energy efficiency. Residential and commercial customers must adopt energy conservation measures to meet the State's 2030 and 2045 decarbonization goals. By 2030, we will need more than 3,400 gigawatt-hours (GWh) of energy efficiency measures implemented in homes and businesses across the islands to reduce carbon emissions. With customer participation in energy efficiency, generation, and storage, the Integrated Grid Plan will benefit the environment by reducing carbon emissions by 75% by 2030 relative to 2005 levels.

Actions we can take to begin increasing customer participation:

- Implement new distributed energy resources (DER) programs: Smart DER Tariff and bring-your-own-device options, targeting 1,186 MW of private rooftop solar capacity by 2030
- Implement community-based renewable energy projects for low- and moderate-income customers and the Tranche 1 procurement
- Implement advanced rate designs and conduct time-of-use (TOU) study
- Procure energy efficiency and other grid services to meet grid needs and reduce supply-side requirements
- Review lessons learned from the Phase 2 Tranche 1 community-based renewable energy procurement, and propose changes, if necessary, for a more robust program

Rapid development of low-cost renewables and transmission. The near-term path toward 70% greenhouse gas reduction by 2030 requires wind, solar, and energy storage enabled by transmission facilities as a relatively low-cost way to scale up renewable energy and displace fossil fuels. On O'ahu alone, we will need nearly 3,200 MW of large-scale solar generation by 2050, built on 20,700 acres of land. Developing renewables and transmission will require community support and streamlined regulatory reviews, permitting, and execution.

Actions we can take to start developing low-cost renewables and transmission:

- Update key assumptions based on current market conditions (i.e., fuel forecasts) during and following the Stage 3 request for proposals (RFP)
- Complete Stage 3 procurement and work with stakeholders to execute the projects that are selected
- Complete Land Request for Information to identify potential sites for large-scale renewable generation and development of renewable energy zones in concert with communities
- Issue an additional competitive procurement for renewable dispatchable generation after Stage 3 and determine market for long lead renewable resources (i.e., offshore wind and other technologies to achieve commercial operations by 2035) and renewable energy zones for each island
- Continue finding solutions to improve the interconnection process, including working with State and county agencies

However, if land for renewable projects is more limited in the future, we will need to consider higher-cost alternatives. If low-cost renewables are not available in sufficient quantities in the Land-Constrained scenario, higher-cost alternatives such as increased use of biofuels will need to be considered to meet decarbonization goals.

2.1.3 Create a Modern and Resilient Grid

Renewable generation is just one piece of the energy transformation puzzle. We will also need a modern system of transmission and distribution for customers to power their electric vehicles, connect rooftop solar systems and large-scale renewable generation hubs, support the expansion of affordable housing, and fortify the grid against extreme weather events. *To create a resilient grid with enough capacity to meet the State's policy goals, we will need:*

Investment of $59.4 million in distribution upgrades over the next 10 years. The State's economic and policy goals include developing new housing and commercial development to expand our economy while addressing equity. These homes and businesses will be electrified with clean energy, increasing net demand on the grid. To support this effort, we estimate that over the next 10 years, $59.4 million in distribution investments may be needed. However, we will be actively pursuing the opportunity to partner with our customers to shape energy use and their solar/storage resources to potentially reduce/defer some of the investment needed.

Near-term actions to upgrade the distribution system:

- Issue expressions of interest for qualified distribution non-wires alternatives opportunities
- Prepare extraordinary project recovery mechanism requests to implement distribution upgrades needed to support electrification and expansion of private rooftop solar hosting capacity, and other requests to support expanded distribution capacity for new housing and commercial developments

Investment of $1.33 billion through 2035 to expand or create new transmission interconnection points between renewable projects. The transmission system remains the backbone of the grid. Creating hubs and enabling transmission facilities for large-scale projects will streamline interconnection and provide access to untapped renewable potential and growth in electrified loads. By 2030, investments are needed to create renewable energy zones that connect generation hubs through a modern system of transmission and distribution. Beyond 2030, major transmission expansion is needed on O'ahu, Hawai'i Island, and Maui to reach areas with untapped renewable potential and to increase the capacity for electrification of transportation.

Near-term actions to develop renewable energy zones:

- Continue community engagement to determine feasibility of developing renewable energy zones
- Create a transmission siting and routing process in collaboration with communities, State, county, landowners, and project developers

Initial investment of $190 million to improve the resilience of the transmission and distribution grid. Resilience grid investments are needed to prepare the grid to withstand natural disasters and support deploying microgrids; for example, hardening critical transmission lines, highway crossings, and critical poles on distribution circuits serving vital community infrastructure. These "least-regrets" investments align with the top stakeholder-identified threats: hurricanes, floods, and extreme wind events.

Near-term actions to improve grid resilience:

- Pending Public Utilities Commission approval, implement and execute a 5-year, $190 million climate adaptation program to harden our grid and implement other resilience measures
- Develop resilience modeling and performance target levels of resilience to inform future hardening and other resilience investments
- Leverage an energy transition initiative partnership program and Resilience Working Group to identify other microgrid opportunities
- Execute North Kohala microgrid and RFP, apply lessons learned, and pursue additional microgrid opportunities to enhance community resilience
- Complete rollout of advanced metering infrastructure and obtain approval of phase 2 grid modernization to enhance system reliability and resilience

2.1.4 Secure Reliability through Diverse Energy Sources and Technologies

A diverse grid is a reliable grid—we must invest in a diverse array of resources to provide power that customers can count on, through rain or shine. Modern firm generation is a critical component of a diverse grid. It will replace fossil fuel–based generation and provide a source of stable, consistent power on standby to supplement resources like solar and wind and "fill in the gaps" at times when solar and wind aren't sufficient. *Creating a reliable clean energy grid will require:*

Developing renewable firm generation that is modern and flexible. It is not possible to ensure a consistent, reliable flow of electricity if the entire grid is powered by weather-dependent, energy-limited resources. Investing in firm generation that is flexible, with the ability to quickly start and ramp up, will enable a reliable source of power when conditions are not optimal for solar or wind generation. It will also address vulnerabilities with today's system, where aging thermal units still supply most of our energy.

Rapidly deploying renewable firm generation is also a solution for managing the deactivation of fossil fuel–based generation. The sooner we transition to modern, flexible firm generation and a critical mass of solar, wind, and storage resources, the sooner we can deactivate and retire fossil fuel–based generation. The O'ahu and Maui systems, in particular, will not be reliable if replacement firm generation is not procured prior to retirement of existing firm generators.

Near-term actions to secure reliability:

- Continue to monitor the condition of an aging generation fleet and prepare contingency plans as necessary; manage prudent and essential capital investments in generating units that could potentially be retired or deactivated in the near future, balanced with ensuring short-term reliability
- Acquire new firm generation and solar/wind and energy storage projects through the Stage 3 procurement to facilitate deactivation and retirement of existing fossil-fuel generation through 2035
- Complete a resource adequacy study to review reliability planning methods and renewable resource accreditation methodologies

Adoption of emerging technologies. Shifting to a highly dynamic, decentralized grid will come with risks and uncertainties. It will require investments that we may not be able to identify today, and it will rely on advancements in current technologies. We anticipate that the system of tomorrow will operate in a much faster time scale than today, requiring resources that can act quickly to stabilize the grid. We will need a critical mass of hybrid solar, wind, and/or standalone energy storage plants with grid-forming capability to replace the fossil fuel–based generation they are displacing. By adding many variable, inverter-based resources in various locations, new challenges will arise in ensuring the security of the system.

Current functionality from rooftop solar and energy storage systems poses a risk to system stability. However, these risks may be mitigated through additions in large-scale renewable resources with grid-forming capability, improved performance of customer rooftop solar and energy storage systems (including legacy systems), and technological advancements in operational technologies that actively manage the grid.

Near-term actions to adopt emerging technologies:

- Continue to monitor and evaluate the performance of new solar and storage projects, including continued assessment of system security risks as more renewable systems are brought online
- Continue to monitor and invest in advanced technologies to operate the high inverter-based grids and seek new grid technologies to improve the reliability of the grid
- Implement IEEE 2800-2022 in future large-scale inverter-based resource projects
- Continue engagement with the DER industry to improve inverter performance to address system security concerns
- Continue evaluating advanced equipment for providing system stability (e.g., grid-forming STATCOM)
- Develop EV standards for vehicle to grid to get ahead of potential system security risks seen today with rooftop solar systems

2.2 Timeline and Renewable Portfolios

The Integrated Grid Plan outlines the amount of renewable resources we will need to procure to meet statewide decarbonization goals. displays a high-level timeline of adding renewable resources, retiring fossil fuel–based generation, and reducing carbon emissions.

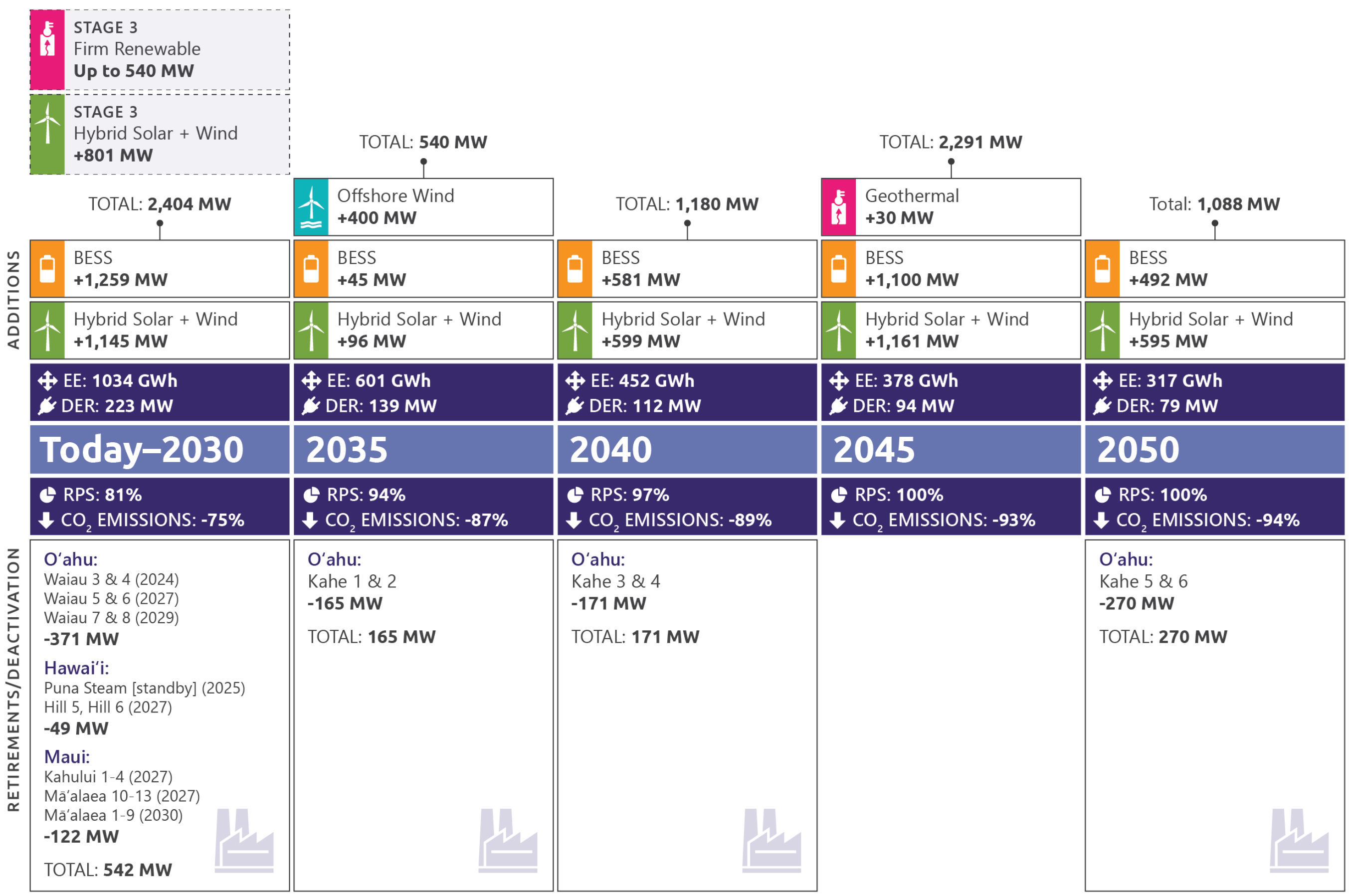


Figure 2-1. Proposed timeline of adding renewable resources, retiring or deactivating fossil fuel–based generation, and reducing carbon emissions

The following is an overview of our plan and the resources we seek to obtain between now and 2035 for each island.

2.2.1 O'ahu by 2035

- 1,067 MW/2,186 GWh of solar and energy storage or onshore wind
- 400 MW/2,114 GWh of offshore wind
- 240 MW/379 GWh of private rooftop solar
- 1,209 GWh of energy efficiency
- 180 MW of Phase 2 community solar
  - 14 MW LMI and Phase 2 projects have already been selected

Figure 2-2 presents a preferred plan generation mix for O'ahu (Base).

Figure 2-3 presents a preferred plan generation mix for O'ahu (Land-Constrained)

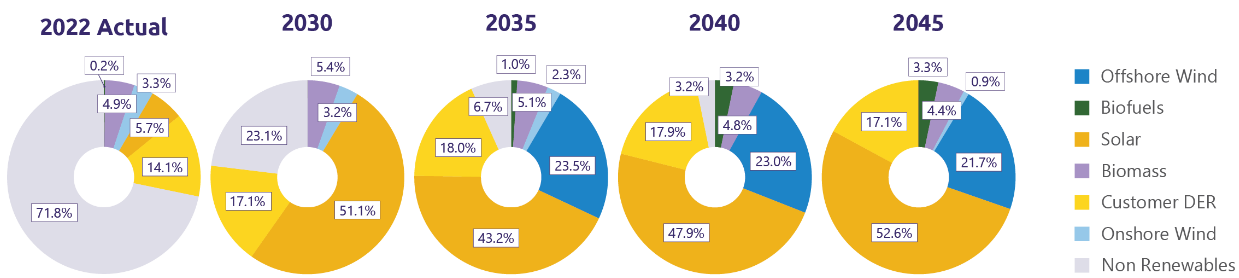


Figure 2-2. Preferred plan generation mix: O'ahu (Base)

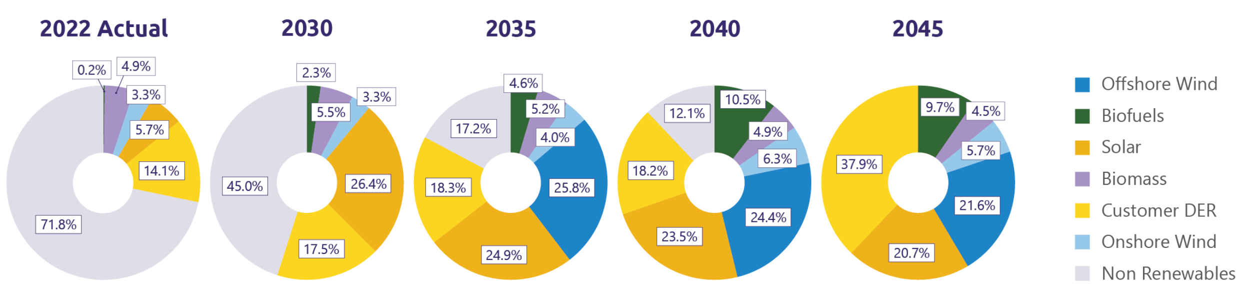


Figure 2-3. Preferred plan generation mix: O'ahu (Land-Constrained)

2.2.2 Hawaiʻi Island by 2035

- 51 MW/209 GWh of solar and energy storage or wind
- 58 MW/85 GWh of private rooftop solar
- 218 GWh of energy efficiency
- 33 MW of Phase 2 community solar
  - 15 MW LMI and Phase 2 projects have already been selected

Figure 2-4 presents a preferred plan generation mix for Hawaiʻi Island.

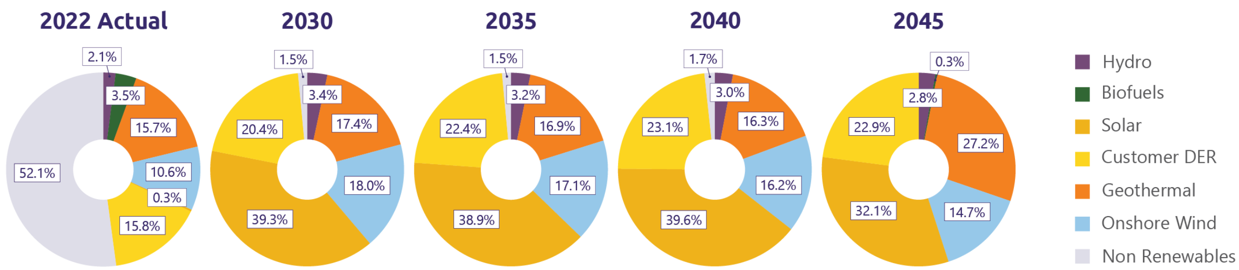


Figure 2-4. Preferred plan generation mix: Hawaiʻi Island

2.2.3 Maui by 2035

- 103 MW/211 GWh of solar and energy storage or wind
- 62 MW/100 GWh of private rooftop solar
- 206 GWh of energy efficiency
- 33 MW of Phase 2 community solar
  - 8 MW LMI projects have already been selected

Figure 2-5 presents a preferred plan generation mix for Maui.

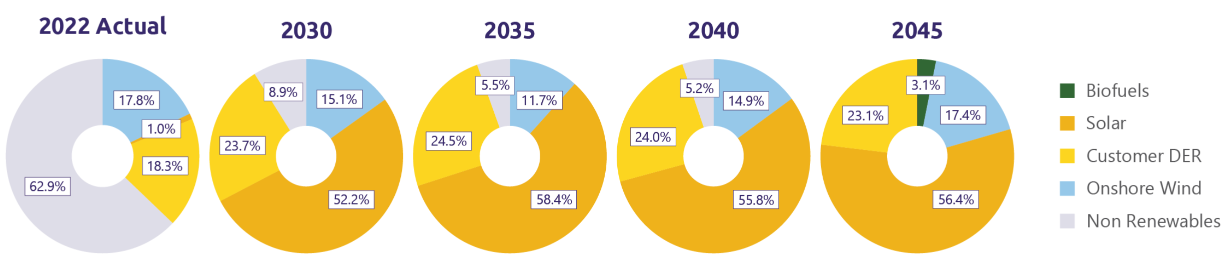


Figure 2-5. Preferred plan generation mix: Maui

2.2.4 Lāna‘i by 2035

- 5.5 MW/5.7 GWh of solar and energy storage or wind
- 17.5 MW/35.8 GWh of community solar (Lānaʻi CBRE request for proposals [RFP])
  - 17.5 MW have already been selected
- 0.6 MW/1.0 GWh of private rooftop solar
- 1.2 GWh of energy efficiency

Figure 2-6 presents a preferred plan generation mix for Lānaʻi.

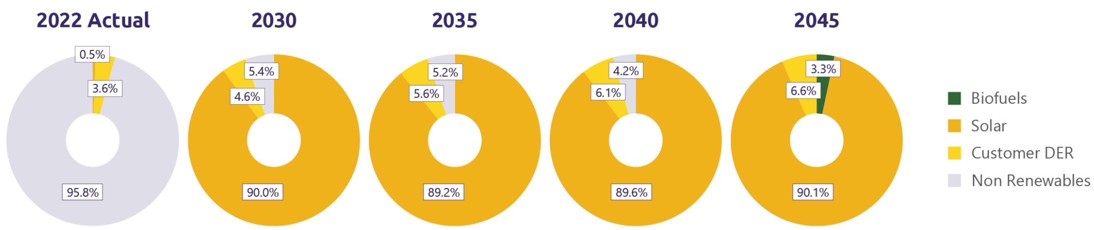


Figure 2-6. Preferred plan generation mix: Lāna‘i

2.2.5 Moloka‘i by 2035

Molokaʻi is preparing a Molokaʻi Community Energy Resilience Action Plan: an independent, island-wide, community-led and expert-informed collaborative planning process to increase renewable energy on the island. The Molokaʻi Clean Energy Hui by Sustʻāinable Molokaʻi is coordinating the action plan. Hawaiian Electric is providing technical support to the Molokaʻi Clean Energy Hui in its planning process to develop a portfolio of clean energy projects to achieve 100% renewable energy for the island that is feasible, respectful of Molokaʻi's culture and environment, and strongly supported by the community.

Figure 2-7 presents a preferred plan generation mix for Molokaʻi. This is subject to change based on the ongoing planning process on Molokaʻi. Hawaiian Electric will continue to work with the Molokaʻi Clean Energy Hui to align our planning efforts.

- 13.8 MW/24.1 GWh of solar and energy storage or wind
- 1.0 MW/1.7 GWh of private rooftop solar
- 1.2 GWh of energy efficiency
- 2.75 MW of Phase 2 community solar
  - 2.45 MW have already been selected to the final award group

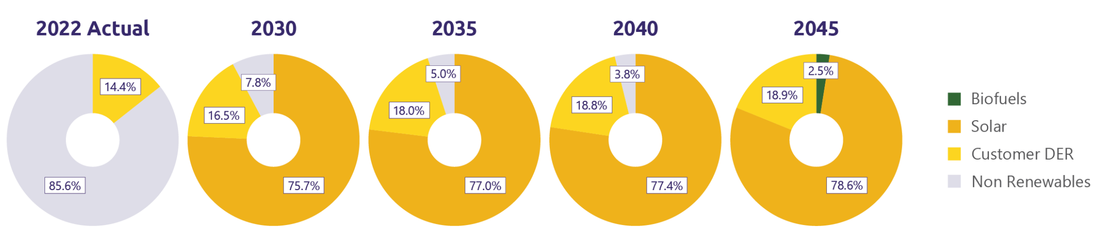


Figure 2-7. Preferred plan generation mix: Moloka‘i

2.3 External Actions and Policies for Successful Implementation

Decarbonizing the electric grid by 2045 will depend on many conditions, actions, and policies beyond Hawaiian Electric. External conditions and actions that will support successful implementation include:

ECONOMIC CONDITIONS AND ACTIONS
Easing of supply chain and inflationary pressures.
Federal funding (e.g., bipartisan infrastructure bill and Inflation Reduction Act) for incentives that remove barriers to customer adoption of EE measures and electric vehicles.
Federal funding to offset the cost of renewable energy projects and transmission and distribution resilience investments.
Investments in grid modernization and advanced technologies to improve operational situational awareness and active management of operational technology.

CUSTOMER AND COMMUNITY ACTIONS
Robust customer and community participation in energy efficiency, generation, and storage.
Customer and community engagement in and acceptance of energy plans and projects.

RESOURCE AND TECHNOLOGICAL CONDITIONS
Better-than-expected performance of large-scale solar, battery storage, and distributed energy resources, especially during transient or contingency events.

POLICIES AND REGULATORY CONDITIONS
Policies that accelerate stock turnover of less efficient appliances, equipment, and combustion vehicles and changes to building codes and standards that encourage zero-emissions appliances and equipment.
Policies that promote affordability and equity.
Efficient regulatory action and decision making.
Land use policies that promote renewable energy development, including other land being made available (e.g., private land, federal lands, etc.)
Policies that remove barriers to siting and permitting large-scale renewable projects and transmission infrastructure. For example, a separate process or entity that coordinates or has the authority to approve a variety of permits needed to execute a renewable project.
Flexibility in air permitting and mandates to manage reliability and transitions to renewable resource replacements.
Policies that provide incentives to communities and residents to host renewable projects and transmission infrastructure.
Policies that provide developers and landowners incentives to develop renewable projects in certain locations.
Policies that support a technical workforce pipeline to continue the work needed to accelerate the transition and transition fossil fuel–related jobs to clean energy jobs.

2.4 Potential Risks and Challenges

Many risks and potential challenges could delay progress toward State decarbonization goals. The primary threat to progress is the status quo and policy inaction to the above-listed recommendations. We have also experienced the acute risks to implementation and execution of renewable projects over the past couple of years because of persistent supply-chain and inflationary pressures (or economic recession) that make customer technologies and large-scale projects unaffordable for customers or that adversely impact the cost of equipment, materials, and labor.

2.5 Next Steps

As we move beyond planning, we are turning our focus to creating an energy marketplace, building upon our efforts to date in acquiring clean energy solutions through competitive procurement for large-scale resource and community-based energy projects, grid services purchase agreements, and customer DER programs.

To create a viable energy marketplace, we will need to routinely conduct procurements and adjust program and pricing mechanisms, in a similar but more efficient and streamlined manner to the procurement activities since 2017. To meet our 70% greenhouse gas reduction goal by 2030, we will need to increase customer participation in energy efficiency, generation, and storage and issue up to two additional competitive procurements. Figure 2-8 shows our proposed near-term actions.

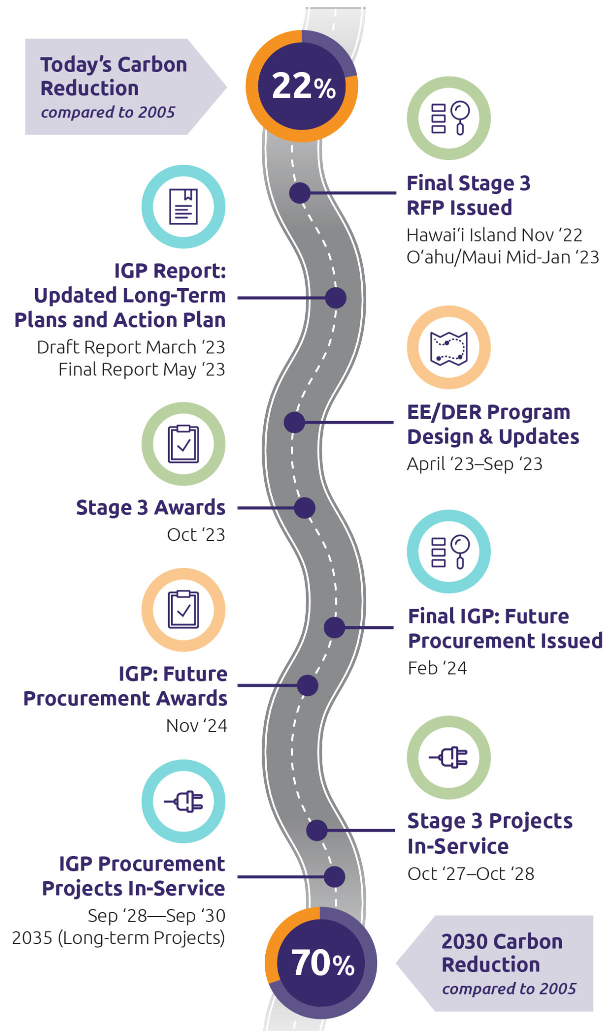


Figure 2-8. Proposed near-term actions, 2023–2035

2.5.1 Public Utilities Commission Requests

To move from planning into implementation, we ask that the Public Utilities Commission:

- Approve the Integrated Grid Plan to serve as a foundational element for Hawaiian Electric and regulatory actions, including in interrelated dockets in the near term
- Open a new docket for competitive bidding related to grid-scale resources, non-wires alternatives, and grid services as described in this report, pursuant to the revised competitive bidding framework previously approved for use in the Integrated Grid Plan

3. Introduction

At Hawaiian Electric, customers are at the heart of our work today and our vision for the future. We are deeply rooted in our communities, and we strive to serve the energy needs of each person in Hawaiʻi with purpose, compassion, empathy, and aloha for our fellow humans and our natural environment. We are committed to empowering our customers and communities with affordable and reliable clean energy, and providing innovative energy leadership for Hawaiʻi.

Hawaiian Electric has the privilege of serving as Hawaiʻi's largest electric utility. We serve 95% of Hawaiʻi's 1.4 million residents on the islands of Hawaiʻi, Oʻahu, Maui, Lānaʻi, and Molokaʻi, each with separate grids. Since 2010, we have nearly tripled the amount of renewable energy we generate, in large part due to the contributions of our customers. Figure 3-1 shows our renewable energy portfolio from 2011 through 2022. Customer-sited solar currently accounts for most of our renewable energy generation.

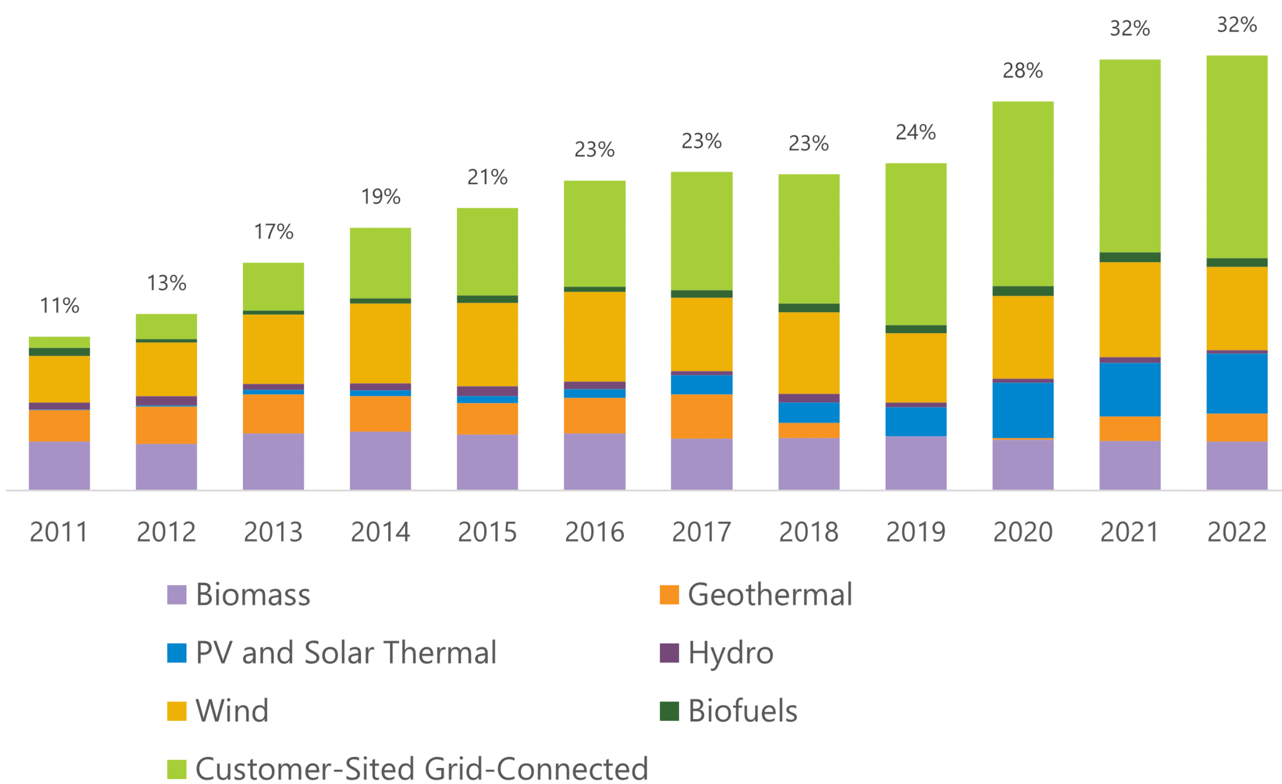


Figure 3-1. Hawaiian Electric renewable energy portfolio, 2011–2022

Together with stakeholders, customers, and communities, we have made significant progress toward our decarbonization goals. Among the accomplishments:

- **35%** of single-family homes have rooftop solar and **4,408** new residential rooftop solar systems.
- Total solar capacity, primarily from customers with rooftop solar, has grown to more than **1,118** MW.
- **91%** of new rooftop solar is being installed with battery energy storage.
- Greenhouse gas emissions have been reduced by **22%** compared to 2005.
- We have expanded customer energy options with innovative programs like Battery Bonus and Shared Solar.
- Installation of public EV charging infrastructure has expanded to **31** chargers at the end of 2022 with plans to have a total of 40 chargers by the end of 2023.
- Advanced meters have been deployed to more than **40%** of customers on Oʻahu, Hawaiʻi Island, and Maui.
- Two stages of competitive procurement for renewable dispatchable generation (RDG) have been executed (referred to as **Stage 1** and **Stage 2**), with the first two large-scale solar plus battery energy storage projects in operation: Mililani 1 Solar, a 39 MW/156 megawatt-hour (MWh) battery and Waiawa Solar, a 36 MW/144 MWh battery. Additional projects are in the pipeline and expected to reach commercial operations over the next couple of years.
- A third stage (**Stage 3**) of competitive procurement for renewable dispatchable generation has been issued and firm generation is currently in progress.

We are proud of the progress we have made, but we still have a long way to go.

3.1 Climate Change Action Plan

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 do our part in cutting global emissions, Hawaiian Electric announced a bold Climate Change Action Plan in 2021.

Our Climate Change Action Plan sets the ambitious goal of reducing electric-sector greenhouse gas emissions in 2030 by as much as 70% compared to 2005 levels. It also sets the goal of reaching net-zero carbon emissions by 2045, meaning whatever small amount of emissions we produce will be captured or offset. Figure 3-2 illustrates the Climate Change Action Plan goals.

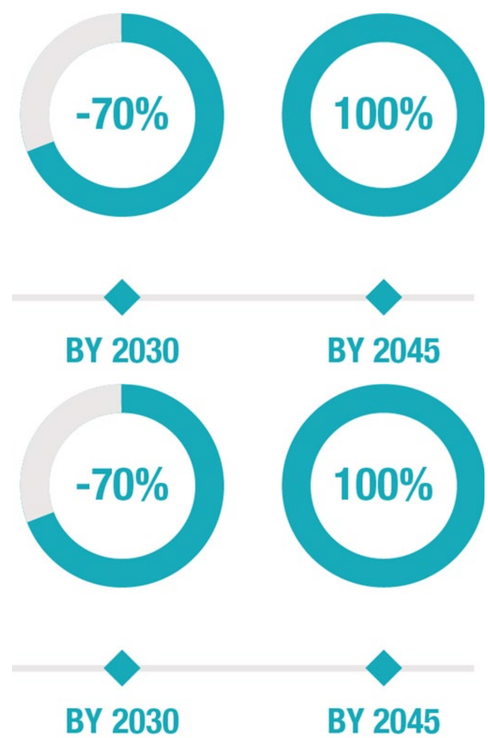


Figure 3-2. Hawaiian Electric's Climate Change Action Plan carbon emission goals

This commitment by Hawaiian Electric represents a significant down payment on the economy-wide reduction that Hawai'i will have to achieve to align with nationwide and global greenhouse gas reduction goals. Statewide decarbonization will require collaboration across sectors, with transportation, agriculture, and other industries working to reduce and offset emissions.

3.2 Hawai'i Powered

A key strategy to reach net-zero emissions is generating 100% of our energy from renewable resources. In 2015, Hawai'i became the first state in the nation to direct its utilities to generate 100% of their electricity from renewable energy sources by 2045. Hawaiian Electric is dedicated to partnering with customers, communities, and other stakeholders to reach this energy goal.

We call our vision for using 100% renewable resources "Hawai'i Powered." Clean energy for Hawai'i, by Hawai'i:

- Supports our Climate Change Action Plan and the State's decarbonization goals
- Achieves energy independence
- Expands energy choices for customers and helps stabilize rates

3.3 Overview of Integrated Grid Planning

Integrated Grid Planning brought many people together to determine how to create a resilient and reliable grid that will meet future energy needs, stabilize costs for customers, and use 100% renewable resources. Hawaiian Electric began the planning process in 2018.

Powering a safe, secure, reliable, and resilient grid with Hawai'i's natural resources, whether on a small scale with individual customers, or through large-scale renewable energy providers, will require thoughtful and coordinated energy system planning in partnership with local communities and stakeholders alike. Additionally, the electric grid of tomorrow will look dramatically different from the electric grid of the past, as it will need to efficiently handle complex tasks not originally imagined. With a renewed focus on comprehensive energy planning, we believe that customers will benefit from a process that will identify the best options to affordably move Hawai'i toward a reliable, resilient clean energy future with minimal risk. The Integrated Grid Plan is rooted in customer and stakeholder input. We endeavor to create customer value by:

- Harmonizing resource, transmission, and distribution planning processes
- Evaluating the collective identified system needs
- Coordinating solutions that provide the best value on a consolidated basis

This approach appraises the total needs of the system and considers all alternatives from customers, independent providers, and the utility. It led us to identify solutions that are the lowest cost and/or best fit to create a more resilient, reliable, and sustainable grid that can meet the needs of Hawai'i's residents and businesses.

Integrated Grid Planning diverged from traditional energy planning practices. It streamlined traditionally disparate planning and procurement activities into a unified process. For instance, our planning framework establishes a marketplace for grid solutions that is integrated into the optimization and decision-making process, increasing opportunities for developers and customers to provide energy and grid services.

Throughout the planning process, we maintained transparency through active stakeholder, customer, and community engagement. See

Section 4 for details about our communication and outreach approach.

As illustrated in Figure 3-3, Integrated Grid Planning consisted of four high-level steps:

- **Data collection.** We developed forecasts and input assumptions to drive the planning and procurement process.
- **Plan definition.** We identified resource, transmission, and distribution needs to establish an optimal portfolio of solutions to meet grid needs, policy goals, and system reliability standards. This includes a near-term action plan and directional, long-term pathways to meet policy goals.
- **Growing a clean energy marketplace.** We seek to identify resource, transmission, and distribution solutions and grow the energy marketplace through multiple sourcing mechanisms: procurements, pricing, and programs.
- **Plan refinement.** We evaluated and optimized the resource, transmission, and distribution solutions to identify proposed solutions for review (i.e., investments, third-party contract, programs, and pricing proposals) for review by the Public Utilities Commission.

Figure 3-3. High-level steps of Integrated Grid Planning

3.4 Key Considerations

The core challenge of Integrated Grid Planning was to create a clean energy grid that balanced the key considerations of time, affordability, land use, community, and resilience and reliability, as shown here.

Time

How long will it take to come online?

Affordability

What will it cost to design, build, and maintain?

Land use

What is the footprint? How does this affect other land use priorities?

Community

How will it affect neighbors, jobs, and the environment?

Resilience and reliability

Will it hold up to a natural disaster and can it bounce back? How will it meet future energy demands based on electric vehicles, solar projects, population, and other factors?

Together with stakeholder groups and community members, we worked to prioritize, balance, and connect the key considerations. Figure 3-4 displays the ranking of key considerations by community members who voted on their priorities online and at events on Hawai'i Island, Maui, and O'ahu in 2022.

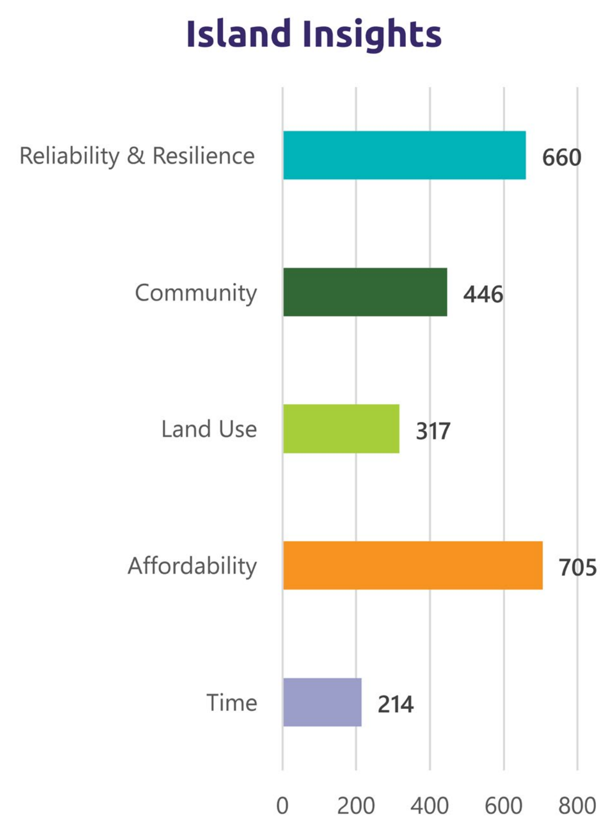


Figure 3-4. Key considerations ranked by community members (voting online and in person)

Throughout Integrated Grid Planning, we focused on the two considerations that we repeatedly heard were of top concern and interest to community members: affordability and reliability/resilience. This report provides the most affordable and reliable pathways to decarbonize our electric system.

3.5 Pathways to 100% Renewable Energy

We evaluated five pathways to achieving 100% renewable energy over a planning horizon to year 2050. On O'ahu we evaluated an additional pathway called "Land-Constrained" to represent the possibility that there would be insufficient land to site large-scale renewable energy projects. The objective of each pathway is to best serve our customers' future needs and preferences, while allowing flexibility to adapt to the inevitable uncertainties ahead, including changes in customer preferences and conditions. This planning approach is customer-centric, as it defines the residual needs of the grid after accounting for customer resources. In developing these possible pathways, we took into account:

- Island-specific conditions
- State policies as described in Section 5
- Customer trends and adoption rates of new technologies
- How future State or federal policies may impact customer choices
- Design and implementation of potential renewable energy zones

The following is an overview of the five pathways. See Section 8 for details on these pathways per island.

Pathway	Overview
Base electricity demand	Customers continue to adopt technologies (private rooftop solar, energy storage, electric vehicles, and energy efficiency) based on current projected market conditions and customer trends. EV owners manage their charging and mostly charge during the day when solar resources are abundant, and electricity is cheapest. At this time, we believe this pathway is the most probable trajectory.
Low electricity demand	Customer adoption of technologies continues at a much higher pace than expected, such as energy efficiency and private rooftop solar, but EV adoption remains slow. In this future, the electricity demand we must serve is much lower than in all other pathways and fewer large-scale resources will be needed to achieve 100% renewable energy.
Faster customer technology adoption	Customer adoption of all technologies, private rooftop solar, and electric vehicles; energy efficiency is higher and accelerated compared to the market forecasts and EV owners manage to charge their vehicles during the day when solar is abundant. In this future, the electricity demand is higher than the Base electricity demand pathway but lower than the High electricity demand pathway.
High electricity demand	Customer adoption of technologies continues at a much slower pace than expected; however, EV adoption accelerates because of aggressive State or federal policies, but owners charge their vehicles when the grid is most stressed (i.e., unmanaged EV charging). In this future, the electricity demand we must serve is much higher than in all other pathways and more large-scale resources will be needed to achieve 100% renewable energy.
Land-constrained	This pathway recognizes the possibility on O'ahu that insufficient land may be available to develop large-scale resources or to produce local biofuels needed to achieve 100% renewable energy, while balancing other State goals of affordable housing and food sustainability. This pathway helps us understand the impact of limited land availability for future solar, onshore wind, and biomass development. In this pathway customer adoption is the same as the Base pathway where customers adopt technologies based on current market and customer trends.

3.6 Renewable Energy Planning Principles

The following principles guided our technical analyses and community conversations as we moved through Integrated Grid Planning:

- ***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 Hawai'i 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 LMI 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 are vital for our economy, national security, and critical 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 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, policymakers, and other stakeholders.

4. Community and Stakeholder Engagement

Meaningful and sustained community and stakeholder engagement is at the heart of Integrated Grid Planning. It has been instrumental in aligning our planning with statewide priorities and moving Hawai'i toward a more equitable clean energy future. Since planning began in 2018, we have worked to foster partnerships with communities that we are a part of and serve by sharing transparent information and listening, learning, and implementing their feedback into the Integrated Grid Plan.

We are grateful for the involvement of thousands of community members throughout the planning process, and we appreciate the opportunities we have had to collaborate on potential solutions.

In this section, we summarize outreach and engagement with community members and stakeholders, what we heard, and how we implemented the feedback we received. See Appendix A for copies of materials from stakeholder and community engagement.

4.1 Engagement Approach and Stakeholder Groups

We followed an engagement framework for consistent and frequent communication with community members and stakeholders to gather input and share information throughout the planning process. Figure 4-1 illustrates this framework, with the reciprocal flow of information and feedback between Hawaiian Electric and our primary stakeholder groups.

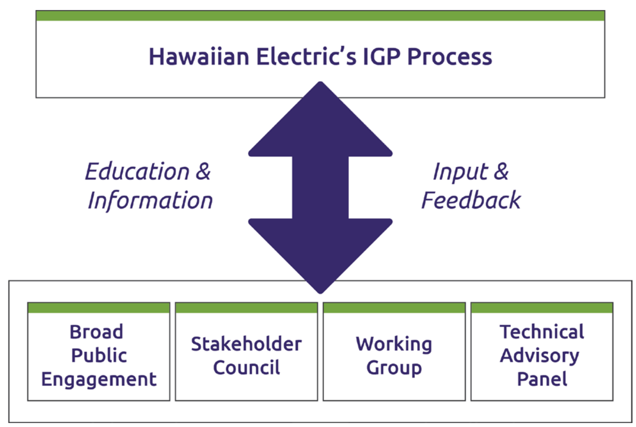


Figure 4-1. Stakeholder engagement framework

We engaged four main groups in planning for a clean energy grid: the Stakeholder Council, the Technical Advisory Council, Working Groups, and the public.

4.1.1 Stakeholder Council

This group helped to ensure that our planning aligned with interests across the islands. It consisted of one representative from the following customer and stakeholder interests:

- City/county and/or community representative (one from each island/county)
- Consumer advocate
- Demand response
- Energy efficiency
- Energy storage
- Environmental advocate
- Hawaiʻi Public Utilities Commission
- Independent power producers (utility-scale resources)
- Large commercial and industrial customers
- Small solar developers
- State of Hawaiʻi Energy Office
- Sustainability advocate (local)
- Technical Advisory Panel Chair
- U.S. Department of Defense

Beginning in fall 2018, we hosted virtual and in-person Stakeholder Council meetings aligned with planning milestones and updates. Figure 4-2 shows Stakeholder Councilmembers and Hawaiian Electric team members at an in-person Stakeholder Council meeting in December 2022.

See Appendix A for presentations and notes from Stakeholder Council meetings.

Figure 4-2. Stakeholder Council meeting, December 2022

4.1.2 Technical Advisory Panel

This group provided an independent source of peer assessment for the technological and engineering considerations of planning for a Hawai'i Powered future. Panel members came from internationally recognized utilities, market operators, and research organizations with engineering expertise in resource, transmission, and distribution planning for large-scale and distributed renewable resources. Their review and recommendations on the technical analyses we performed greatly enhanced the quality of our work, and were relied upon by stakeholders to ensure that our analysis was sound and consistent with leading industry practices.

The Technical Advisory Panel met on an approximately monthly basis, aligned with planning milestones and updates. See Appendix A for presentations and notes from Technical Advisory Panel meetings.

4.1.3 Working Groups

On an as-needed basis, we formed specialized groups of experts who addressed specific topics in an advisory-only capacity. The Working Groups included:

- **Forecast Assumptions Working Group:** Supported development of forecast assumptions and sensitivities for Integrated Grid Plan models. This group concluded in March 2021 when we issued the draft March 2021 Inputs and Assumptions Update. Further updates to the forecast assumptions were discussed in the Stakeholder Technical Working Group.
- **Resilience Working Group:** Supported the development of resilience planning criteria for Hawai'i's energy system including resource, transmission, and distribution in relation to potential community and economic impacts. This group concluded with the issuance of the Resilience Working Group Report in June 2020. It is expected to resume as we continue our resilience planning discussions in 2023.
- **Distribution Planning and Grid Services Working Group:** Supported enhancements to the methods and tools for distribution planning and the integration with resource and transmission planning. This working group concluded with the issuance of the Distribution Planning Methodology and Non-Wires Opportunity Evaluation Methodology in June 2020.
- **Market Working Group**: Comprised four interrelated subgroups to support development of the sourcing and evaluation steps in the planning process:
  - **Standardized Contract Working Group:** Developed standardized contracts and service agreements, beginning with the grid services purchase agreement and our model renewable dispatchable generation power purchase agreement (PPA) and model firm PPA. This group concluded with the review of the model Grid Services Purchase Agreement in March 2019.
  - **Grid Services Working Group:** Identified and defined additional energy, capacity, ancillary, and non-wires services. This group concluded with the completion of the soft launch request for proposal for non-wires alternatives (NWAs) in May 2020.
  - **Solution Evaluation and Optimization Working Group:** Focused on the methods for evaluating and optimizing multiple solutions for multiple grid services. This group concluded in March 2021 when we issued the draft March 2021 Grid Needs Assessment and Solution Evaluation Methodology. Further updates to the

planning methodology were discussed in the Stakeholder Technical Working Group.

    - **Competitive Procurement Working Group:** Proposed changes to the Public Utilities Commission's Framework for Competitive Bidding to reduce barriers to market participation and enable alignment with the Integrated Grid Plan. This working group concluded in February 2021 upon filing of the revised competitive bidding framework that will be used during the solution sourcing phase of the process.

- **Stakeholder Technical Working Group:** Formed in June 2021 by combining the Forecast Assumptions, Distribution Planning, Solution Evaluation and Optimization, and Grid Services Working Groups. The Stakeholder Technical Working Group provided and continues to provide input on technical issues and helped increase transparency in the planning process. Consolidating the original Working Group structure streamlined planning efforts by focusing stakeholder time and efforts, providing opportunities for stakeholder presentations, and allowing for robust and comprehensive discussion and collaboration on technical topics.

Working Groups met on an as-needed basis throughout the planning process. See Appendix A for presentations and notes from Working Group meetings.

4.1.4 Public

The public consists of customers and community members across the islands we serve.

We viewed the public as an active and essential partner in Integrated Grid Planning, and we committed to equitable, inclusive, and transparent community engagement each step of the way.

We actualized this commitment by:

- Providing accessible and inclusive opportunities to engage. This included offering multiple ways to engage (both online and in person).
- Prioritizing outreach to underserved and potentially most impacted communities, including people who live in rural areas and people closest to places where new energy facilities may be located. We listened to community members' experiences, priorities, and vision for a clean energy future, and we used their feedback to shape planning outcomes.
- Being accountable to feedback we have received by reviewing and considering public feedback as part of planning decisions, including where to locate new energy facilities.

In the following section, we describe the actions we took to engage the public throughout Integrated Grid Planning.

4.2 Public Engagement Tools and Strategies

We used an array of outreach tools and strategies to meet community members where they were, both online and in person. We tailored our strategies to each island, recognizing that they have unique needs, conditions, and opportunities for decarbonization and public participation.

Most of the Integrated Grid Planning process took place over the course of the COVID-19 pandemic, with community engagement opportunities beginning in March 2020. Public health and safety were our top priority, and we worked to align our outreach with all local, State, and federal guidelines for pandemic safety practices. This included extending the duration of opportunities to share input through virtual/online formats.

4.2.1 Integrated Grid Planning Website, Document Library, and Email

In 2019, we launched the Integrated Grid Planning website (hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning) to share information on planning progress and engagement activities. We also created a project email address (IGP@hawaiianelectric.com), which we maintained and managed throughout the planning process to gather and share information. Community members joined the email list by signing up at public meetings or through the Integrated Grid Planning website.

We updated the website on an ongoing basis throughout the planning process. This included maintaining a document library with copies of technical analyses, reports filed with the Public Utilities Commission, and copies of stakeholder and community presentations and meeting notes. As the planning process evolved, the growing volume of project documents prompted a need for improved library organization. In March 2022, the Public Utilities Commission requested that we improve the clarity and navigability of the library, with a more consistent system for document descriptions, dates, titles, and categories.

We responded to this request by adding new search functions and category tags, as well as consistency in document titling and captioning. We posted notifications about the updated library on the project website homepage and Hawai‘i Powered participation site. (See Section 4.2.3, below, for information about the participation site and e-newsletter.) Figure 4-3 displays a screenshot of the updated document library.

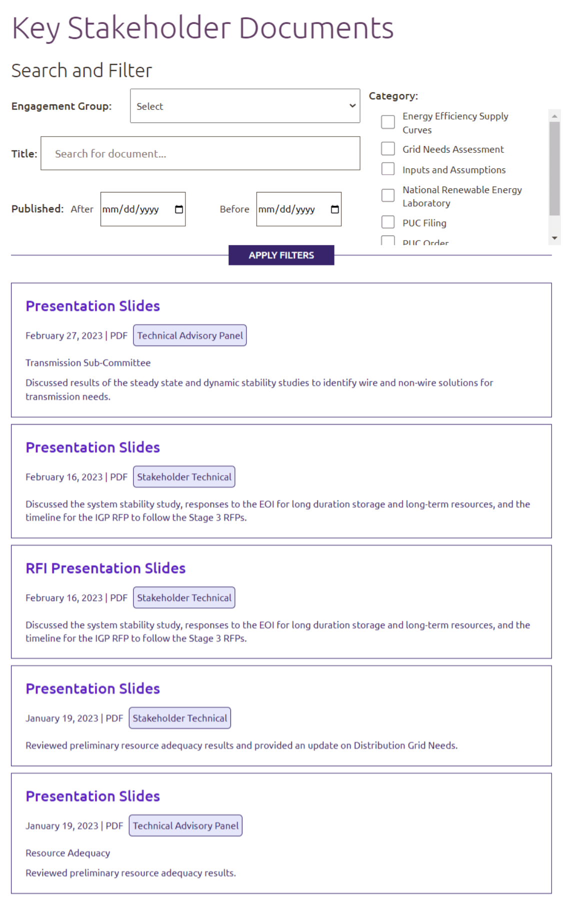


Figure 4-3. Updated document library on the Integrated Grid Planning project website

4.2.2 Public Open Houses

Before the COVID-19 pandemic, in early March 2020, we began our initial campaign of public outreach and engagement, connecting with 1,421 community members in person and online. The engagement goal of this outreach campaign was to connect with the public, provide a general overview of Integrated Grid Planning, and gather input on what is most and least important to consider as part of the planning process. Topics included:

- Grid modernization
- Grid-scale renewables
- Rooftop renewable energy
- Community-based renewable energy (CBRE)
- Electrification of transportation
- Resilience
- Careers at Hawaiian Electric

We invited the public to the open houses by sharing a press release with local media outlets, emailing all Integrated Grid Plan subscribers, and posting advertisements to social media. We also produced a livestreamed social media segment publicizing the open houses and introducing the Hawaiian Electric team and information boards. Additionally, we provided the Stakeholder Council a communications "toolkit" with fliers and messaging for councilmembers to share with their organizations and communities.

A total of 161 participants joined us at four in-person open houses: two on Hawaiʻi Island, and one each on Oʻahu and Maui. Table 4-1 displays the locations and number of participants at each meeting.

Table 4-1. In-person Participation in March 2020 Public Open Houses

Event Information	Participants
3/3/2020 Kealakehe High School, Kailua-Kona, Hawaiʻi	17
3/5/2020 Hilo High School, Hilo, Hawaiʻi	52
3/10/2020 Hawaiʻi Pacific University, Honolulu, Oʻahu	61
3/12/2020 Hawaiian Electric, Kahului, Maui	31
Total number of in-person participants	161

At each open house, participants visited stations with information boards and then attended a panel discussion. Figure 4-4 shows community members speaking with Hawaiian Electric team members near informational boards. The panel included community members, representatives from energy organizations, and Hawaiian Electric team members.

See Appendix A for a list of the panelists and copies of open-house materials, including informational boards and handouts. During the panel sessions, participants submitted 127 comments and questions ranging from the role of transportation in energy goals, resilience and domestic security, renewable and energy-efficient programs, connections with smaller communities, and community solar program and energy cost calculations.

Figure 4-4. Community members and the Hawaiian Electric team connect at public open houses, March 2020

Each panel session was filmed and broadcasted by local community television networks, allowing those unable to join the opportunity to watch at their convenience. Hawaiian Electric also posted recordings of the panel sessions to the Integrated Grid Planning website after the events. See Appendix A for a list of the local television networks that broadcasted the open houses, as well as a record of the total views for each video recording posted to the website.

We hosted a virtual open house in tandem with the in-person open houses that shared the same information boards and an online version of the community survey. Virtual open-house participants could also leave a comment or email the project team. More than 1,260 people visited the virtual open house between March 2 and 30, 2020, with peak participation on March 9 and 10.

After the open houses, we consolidated comments from in-person and virtual participants and posted summaries of what we heard to the Integrated Grid Planning website. See Appendix A for copies of the summaries. Key themes included:

- Energy reliability and affordability were of top concern to participants.
- Participants expressed interest in personally helping to increase use of renewable energy and reduce greenhouse gases. Participants supported the effort to reduce greenhouse gases by owning and/or driving electric vehicles, switching to solar, and using energy-efficient appliances. Many expressed interest in having rooftop solar installed, or already had solar installed or were waiting for installation. Participants were interested but looking for more information on advanced meter installation and battery storage installation.
- Very little interest was expressed in using transit or carpooling to reduce emissions, and participants expressed the least interest in exploring new technologies to provide more information and control over energy uses.

This input helped to inform future pathways where we evaluated futures with high adoption of electric vehicles, different levels of rooftop solar adoption, and described the distribution system investments needed to ensure that all customers who want rooftop solar can easily interconnect their system to the grid. We also assessed the reliability of the system to ensure that we have the right type of resources to continue reliable service to customers. See Sections 8 and 12 for details about future pathways and reliability analyses.

Pivoting to an online meeting format during the pandemic, Molokaʻi and Lānaʻi virtual community meetings (live presentation with facilitated question-and-answer session) were held in summer 2020 attended by a total of 31 attendees. The meetings were also recorded and posted online for viewing with thousands of views (Molokaʻi had 4,293 views and Lānaʻi had 3,569 views).

4.2.3 Hawaiʻi Powered Public Participation Site

In March 2022, we launched an online public participation site at hawaiipowered.com. The purpose of this site was to provide a dynamic hub for community engagement, with content that helped humanize the planning effort, convey technical concepts in plain language, and offer multiple opportunities to get involved. The participation site paired with the Integrated Grid Planning project website, where community members could explore the document library and learn more about the technical planning process.

We chose the campaign name, "Hawaiʻi Powered," to convey pride, collective action, and shared responsibility in planning for a future grid powered entirely by local renewable resources. This name helped us lead with less technical language than "integrated grid planning" in communications with the public and celebrate finding local solutions for renewable, resilient energy in partnership with many people—within and outside of Hawaiian Electric.

The Hawaiʻi Powered participation site provided:

- An overview of Integrated Grid Planning goals and commitment to community engagement, with multimedia features including a welcome video.
- Learning modules, such as interactive charts, that depict how much renewable energy comes from various local sources with wide-ranging technologies.
- A community survey about energy priorities and a real-time data visualization of the results collected from online and in-person events.
- Information about recent and upcoming Integrated Grid Planning activities on each island.
- Short forms for people to request a presentation for their community groups, contact the project team, and sign up for email updates. As of February 2023, we received a total of six requests for presentations and 22 messages through the "contact us" feature.
- A blog called *Plugged In*, with monthly posts about Integrated Grid Planning milestones, features on customers and Hawaiian Electric team members, and "deeper dives" on technical subjects. See Table 4-2 for a list of blog posts and their purposes. Copies of these posts are provided in Appendix A.
- Monthly Hawaiʻi Powered e-newsletters sharing Integrated Grid Planning updates and blog post links with all project subscribers. We included statements encouraging readers to share each newsletter with their family and friends. The newsletter gained subscribers with each edition, presumably as recipients shared the email with their networks.

Table 4-2. Hawai'i Powered Blog Posts, March 2022 to February 2023

Purpose	Blog Post Titles, Publication Dates, and Synopses
Provide transparent updates on Integrated Grid Planning	Announcing Hawaii Powered 3/11/2022 Learn how Hawaiian Electric is moving toward a sustainable future and how you can get involved.
	Shared Solar 101 3/11/2022 Explore how solar power generation goes beyond private rooftop solar panels.
Humanize Hawaiian Electric	Aloha from Hawaiian Electric! 4/18/2022 Meet Colton Ching, who leads Hawaiian Electric's efforts to power the grid with 100% renewables by 2045.
Demystify technical topics	What You Need to Know: 2021-2022 Sustainability Report 4/19/2022 See how much power Hawai'i is cleanly generating, how communities are getting involved in a green future, and more!
	Non-wires alternatives 5/31/2022 Learn about the benefits of NWAs and how they fit into our clean energy future.
	Inputs and Assumptions: What does the data really mean? 9/6/2022 Learn about the data and modeling that goes into planning for enough renewable energy to power our future grid.
	Distributed Energy Resources: A diverse grid is a strong grid 7/6/2022 Learn how diversifying energy generation is necessary to a clean energy future.
Promote community-driven clean energy initiatives and community engagement efforts	Molokai residents receive kits to help save energy at home 7/5/2022 Read about the Moloka'i residents who picked up energy saving kits from Hawai'i Energy, the County of Maui Department of Water Supply, and Hawaiian Electric.
	Building Resilience in North Kohala: A collaborative approach to strengthen our communities 8/1/2022 Read more about this community's collaborative approach to energy resilience.
Encourage behavior changes and participation in clean energy planning	Energy Efficiency: The power to change is in our hands 6/1/2022 Get pro tips on how to be your most energy efficient.
	Electrification of Transportation: Driving toward a renewable future 8/2/2022 Check out our EV toolkit and how we're preparing for more electric transportation.
	Renewable Energy Zone (REZ) Maps: You know your community best 11/28/2022 We need your help identifying potential project locations.

a. Hawaiian Electric published the Energy Efficiency, Distributed Energy Resources, and Electrification of Transportation blog posts in advance of launching the inputs and assumptions data dashboard (see information about the dashboard below). These three posts built on one another and provided foundations to help people understand the inputs and assumptions used in modeling. We provided links to these blog posts on the inputs and assumptions data dashboard for readers to reference.

From March 2022 to March 2023, the Hawai'i Powered participation site received 2,928 total visits from 1,765 unique visitors.

4.2.4 Inputs and Assumptions Data Dashboard

In September 2022, we launched a complementary site to Hawai'i Powered to share information about the data and models we use to predict how much clean energy we'll need to meet future customer demand. This site, called the inputs and assumptions data dashboard (hawaiipowered.com/iadashboard), provided interactive learning modules and graphs tied to the data sets we used to model future energy scenarios.

Our intent was to help make this highly technical process more accessible by explaining and visually conveying what scenario planning is, what it involves, and why it matters. See Figure 4-5 for a screenshot of the data dashboard homepage.

See Appendix A for more screenshots of the dashboard.

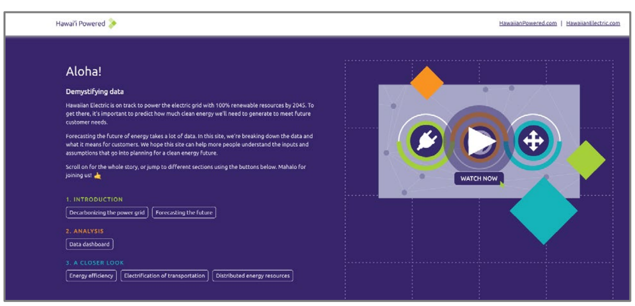


Figure 4-5. Screenshot of the inputs and assumptions data dashboard

To promote the inputs and assumptions data dashboard, we published a blog post, sent an e-newsletter to all subscribers, added a banner notification at the top of the Hawai'i Powered participation site, and posted the welcome video to Hawaiian Electric's social media. We also presented it at a Stakeholder Council meeting and encouraged council members to share it with their networks. The data dashboard received 624 visits from 339 unique visitors from September 2022 to March 2023.

4.2.5 Student and Youth Engagement

We believe it is essential to involve young people in planning for a clean energy future, as they will be its inheritors and stewards.

To that end, we developed a Hawai'i Powered activity book in 2022, with energy exercises, power-up puzzles, creative coloring, and more for learners of all ages. We distributed this activity book at community events on Hawai'i Island, O'ahu, and Maui. Parents and teachers could also download the activity book at hawaiipowered.com. Figure 4-6 shows pages from the activity book. See Appendix A for a copy of the full activity book.

Young people shared their input in ranking the importance of key considerations for the Integrated Grid Plan. See Section 4.2.6 for an overview of the local events and community conversations including the ranking activity.

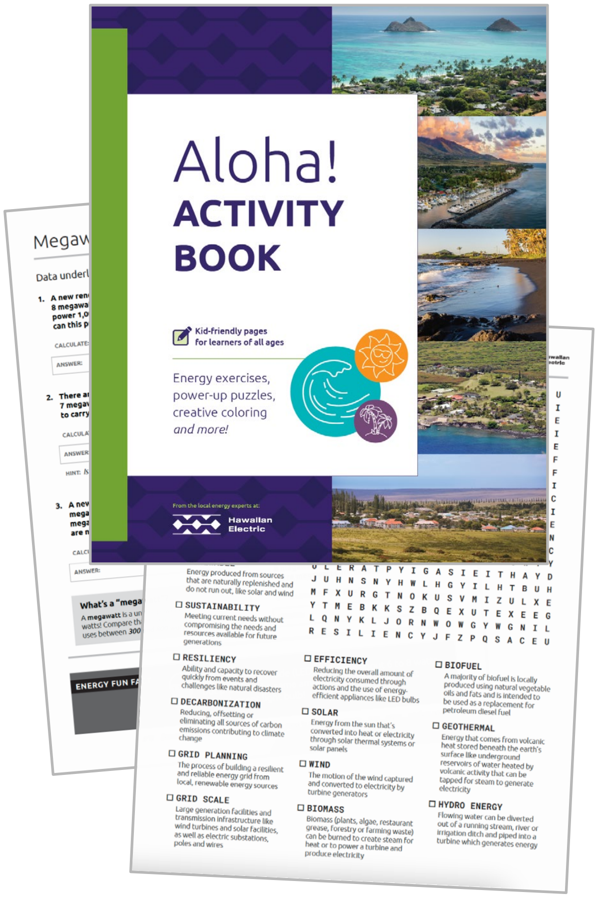


Figure 4-6. Cover and pages from the Hawaiʻi Powered activity book

4.2.6 Local Events and Community Conversations

We conducted our second campaign of community outreach from July 2022 through February 2023. Our goals with this round of outreach were to:

- Tailor our strategies to each island, recognizing that they have unique needs, conditions, and opportunities for decarbonization and public participation
- Connect with community members, listen to and document their ideas, and help answer questions about clean energy planning
- Raise awareness about Integrated Grid Planning and Hawaiʻi's decarbonization goals
- Gather public input on potential future renewable energy zones
- Understand how community members prioritize Integrated Grid Planning key considerations

We participated in local events and hosted community conversations, which were small-group, in-person or virtual events to share information and discuss Hawaiʻi's energy future. Community conversations typically included handouts or display boards with Integrated Grid Planning information, presentations by members of the Hawaiian Electric team, and time for open discussion. Benefits of participating in local events and hosting community conversations included:

- Supporting other local initiatives for clean energy and sustainability outside of Hawaiian Electric. These events included local fairs and festivals, where we staffed booths to reach a broader audience and raise awareness about Integrated Grid Planning and Hawaiʻi's decarbonization goals.
- Focusing our outreach to communities who might be most impacted by energy projects.
- Improving accessibility to our Integrated Grid Planning team by offering more opportunities to connect in more communities, at more places and at more times.

To share information about upcoming opportunities to connect with the Hawaiian Electric team and share input, we maintained an updated list of events per each island on the Hawaiʻi Powered website.

We had the opportunity to connect with community members at 26 events on Hawaiʻi Island, Maui, and Oʻahu in 2022 and early 2023. The following is a summary of the events we attended or hosted on each of the islands.

4.2.6.1 Hawaiʻi Island

We connected with community members at 16 events on Hawaiʻi Island in 2022:

- He Ala Pono Electric Vehicle and Sustainability Fair in Hilo
- Rotary Club of Kona Mauka in Kona
- Kiwanis Club of East Hawaiʻi in Hilo
- AstroDay in Kona
- Girls Scouts STEM Fest in Waikoloa
- Vibrant Hawaiʻi's Resilience Hub Makahiki and Community Resilience Fair in Puna
- Vibrant Hawaiʻi's North Hawaiʻi Resilience Fair in Waimea
- Focus group sessions with Sustainable Energy Hawaiʻi and County of Hawaiʻi mayor's cabinet (two separate events)
- Holualoa Elementary School second-grade class
- Vibrant Hawaiʻi's South Hilo Resilience Fair in Hilo
- Hawaiʻi Island Realtors in Hilo
- Vibrant Hawaiʻi's Kaʻū Makahiki in Kaʻū
- County of Hawaiʻi Senior Lecture Series in Hilo
- Vibrant Hawaiʻi's North Hilo Resilience Fair in Laupahoehoe
- Hamakua Community Development Plan Action Committee in Honokaʻa

We also introduced the Hawaiʻi Powered website at virtual and in-person community meetings in early 2022, prior to the launch of the REZ maps. These events were:

- March to May 2022: County of Hawaiʻi Community Informational Sessions (10 in-person, island-wide events)
- Hawaiʻi Leeward Planning Conference (virtual)
- Waimea Community Association (virtual)

Figure 4-7 shows community members and Hawaiian Electric staff connecting at public events across Hawaiʻi Island, 2022.

Figure 4-7. Participants at engagement events across Hawaiʻi Island

Top to bottom, left to right: *Hawaiian Electric staff discussing renewable energy zones at the 2022 He Ala Pono Electric Vehicle and Sustainability Fair. Girl Scouts with Hawaiian Electric Activity Books at Girl Scouts in STEM event. Community members learning about renewable energy zones at Kiwanis Club of East Hawaiʻi meeting. Community member commenting on renewable energy zones at Vibrant Hawaiʻi event in Puna. Kids with Hawaiian Electric activity books at Vibrant Hawaiʻi in Puna.*

4.2.6.2 Maui

We connected with community members at nine events on Maui in 2022. Figure 4-8 shows community members sharing their priorities for Integrated Grid Planning key considerations at a Hawaiian Electric booth at Maui Arbor Day. Hawaiian Electric team members shared information about the key considerations, and visitors voted on their top priorities using poker chips. We tallied the number of chips at the end of the event, and included the count in our summary of public feedback. See Appendix A for a summary of the ranking of key considerations.

Figure 4-8. Community members use poker chips to vote on the most important grid planning considerations at a Maui Arbor Day event, 2022

We also hosted eight community conversations with 44 representatives of various organizations and interests, including:

- Government officials
- Cultural practitioners
- Community stakeholders/members
- Conservation and environmental advocates and organization representatives
- Businesses
- Agricultural leaders

At these conversations, we shared information about our planning efforts and sought a wide range of perspectives from our Maui community.

4.2.6.3 Oʻahu

From October through December 2022, we held six community conversations across Oʻahu for people to join in person or online. We sent notices about the upcoming conversations to elected officials, neighborhood boards, and energy-related groups and organizations. We also sent a news release to various media outlets and promotional news stories ran in the *Star Advertiser* and *Pacific Business News*.

Each community conversation included an open house (in-person only) followed by a hybrid community workshop (in-person and via Zoom). The workshops were also livestreamed and recorded by ʻŌlelo Community Media. A total of 105 community members joined us in person.

We collected input about the REZ maps and priorities for Oʻahu energy facilities and services, including microgrids. Figure 4-9 shows community members and the Hawaiian Electric team at the Oʻahu community workshops. See Appendix A for a record of all comments received and a summary of what we heard.

Figure 4-9. Community conversations about microgrids on Oʻahu, fall 2022

Oʻahu microgrid planning was an outcome of Hawaiian Electric's involvement in DOE's Energy Transitions Initiative Partnership Project (ETIPP) to improve energy resilience and combat climate change. As part of this partnership, Hawaiian Electric helped identify areas on Oʻahu that are optimal for developing microgrids to build a more resilient electric grid. See Section 10.6 for more information on ETIPP.

MICROGRID:

A microgrid generates, distributes, and regulates the supply of electricity to customers on a smaller, local scale compared to traditional, centralized grids. Microgrids are a group of interconnected loads and distributed energy resources within clearly defined boundaries. They are normally interconnected to the grid and can disconnect from the grid during emergencies. They are best suited to areas near critical infrastructure (such as hospitals and emergency response centers), have access to renewable energy resources, and are prone to prolonged outages during weather events.

We also launched an online interactive map and survey at hawaiipowered.com/etipp about potential locations for future microgrids on O'ahu. The online map and survey helped the public and planners alike consider the technical and practical viability of microgrid development. Figure 4-10 presents a screenshot of the online microgrid survey.

Figure 4-10. Screenshot of the O'ahu microgrids online map and survey

We approached community outreach differently on Lāna'i and Moloka'i, recognizing the unique needs and conditions of energy planning on those islands.

4.2.6.4 Lānaʻi

Much of our grid planning work on Lāna'i happened in collaboration with the majority landowner on the island. The Hawaiian Electric team recently announced its selection of a developer to build and maintain the largest renewable energy project and the first to offer the Shared Solar program on the island. We have completed contract negotiations with DG Development & Acquisition, LLC; however, we have not finalized the contract as the majority landowner, Pūlama Lāna'i, notified Hawaiian Electric of its intent to design and construct microgrids to supply the energy demands of the resorts on Lāna'i.

4.2.6.5 Molokaʻi

Moloka'i is preparing a Moloka'i Community Energy Resilience Action Plan: an independent, island-wide, community-led and expert-informed collaborative planning process to increase renewable energy on the island. The Moloka'i Clean Energy Hui by Sust'āinable Moloka'i is coordinating the action plan. Hawaiian Electric is providing technical support to the Moloka'i Clean Energy Hui in its planning process to develop a portfolio of clean energy projects to achieve 100% renewable energy for the island that is feasible, respectful of Moloka'i's culture and environment, and strongly supported by the community. Learn more at sustainablemolokai.org/renewable-energy/molokai-cerap.

At all community events and talk stories across the islands (as described above), we focused on gathering public input about two topics: Integrated Grid Planning key considerations and the concept of renewable energy zones.

4.2.6.6 Key Planning Considerations

We organized Integrated Grid Planning key considerations into five categories: time, affordability, land use, community, and resilience/reliability. We asked community members to help us understand which considerations are most important to them by ranking their priorities. Figure 4-11 displays the consolidated ranking of key considerations by the people who voted on their priorities at events on Hawaiʻi Island, Maui, and Oʻahu, as well as online at hawaiipowered.com/powerup.

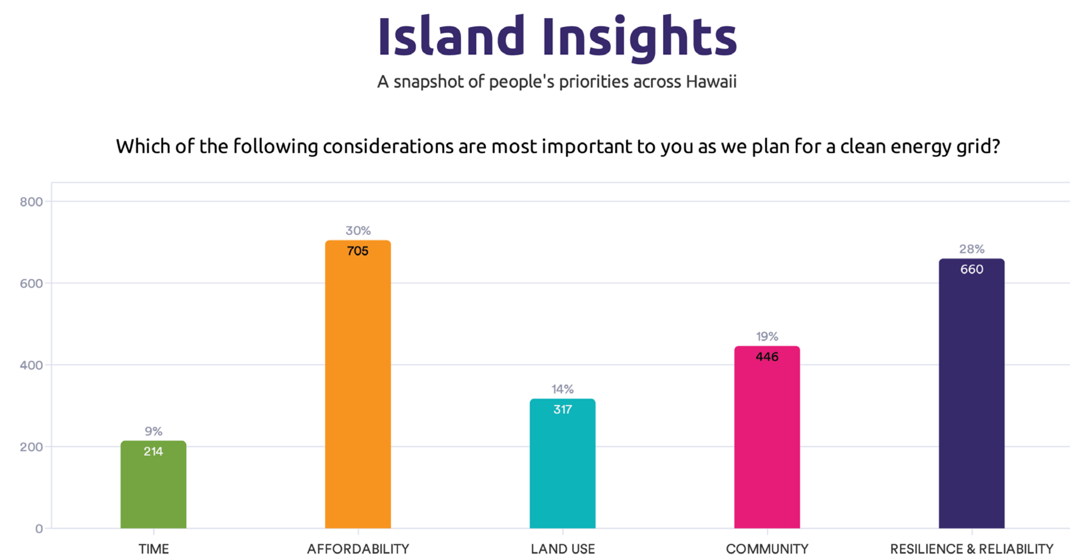


Figure 4-11. Key considerations ranked by community members (voting online and in person)

The ranking activity showed that affordability and reliability are top priorities for many community members. This feedback was consistent with what we heard from community members in our initial phase of public outreach in 2020. This key takeaway informed our Integrated Grid Plan by reaffirming our dedication to finding clean energy solutions that also stabilize customer rates and ensure reliable power that people can count on.

4.2.6.7 Renewable Energy Zones

A core part of the Integrated Grid Planning process was identifying potential future locations for renewable generation facilities and transmission and distribution infrastructure to power the grid with 100% clean energy. Hawaiian Electric partnered with the National Renewable Energy Laboratory (NREL) to estimate the potential for large-scale solar, wind, and distributed rooftop solar developed based on available land, potential capacity, and potential electricity generation for sites across the five islands. This included data about:

- Wind and sun coverage
- Steepness of slopes
- Financial costs
- Access to the site and proximity to existing transmission corridors and grid connections
- Land use and zoning

We identified potential areas called renewable energy zones to complete a high-level analysis of the transmission requirements needed to support the interconnection of each zone to our electric grid.

RENEWABLE ENERGY ZONES:

A renewable energy zone (REZ) is an area that has suitable technical conditions for clean energy generation projects. These projects include cost-effective connections to the existing grid and additional transmission infrastructure required to connect renewable energy generation to customers. A renewable energy zone will enable efficient interconnection of clean energy projects that may include solar, wind, and battery energy storage (among other resources), expanding grid capacity.

We shared information about renewable energy zones with the public online and at the in-person events described above. We invited the public to help us understand the potential impacts, land use opportunities, and community needs and interests within each renewable energy zone on Hawai'i Island, Maui, and O'ahu. Together, public input and technical studies help inform a round of competitive procurements starting to be issued 2023. We will further use the input and data to find synergies between commercial and community interests to refine our grid plans and future competitive procurements in 2024 and beyond.

We launched interactive renewable energy maps at hawaiipowered.com/rez to gather public input. See Figure 4-12 for a screenshot of the interactive map website.

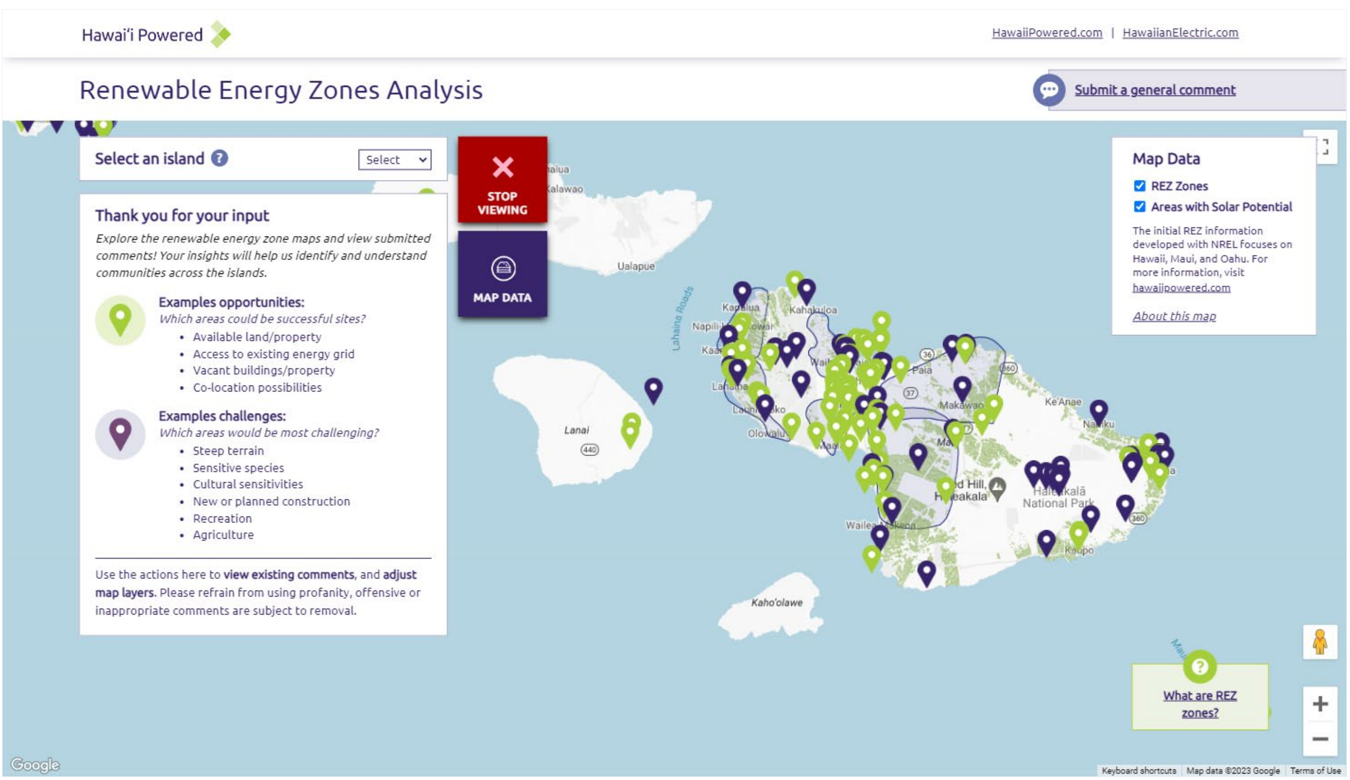


Figure 4-12. Screenshot of the REZ interactive maps

On this site, community members could learn about the development of the potential renewable energy zones and add their input by placing pins with comments on the maps, representing areas of opportunities and challenges. Examples of opportunities and challenges are:

- **Opportunities:** Which areas could be successful sites for future energy projects?
  - Available land/property
  - Access to existing energy grid
  - Vacant building/property
  - Co-location possibilities
- **Challenges:** Which areas would be most challenging?
  - Steep terrain
  - Sensitive species
  - Cultural sensitivities
  - New or planned construction
  - Recreation
  - Agriculture

The REZs input period was open from September 2022 to February 2023. Participants could view other pins and comments on the maps, and the record of comments remained available online once the input period closed.

We conducted a media campaign from January 17 to February 12, 2023, called "Power Up," to promote the REZ website and public input opportunity. The campaign involved placing ads on Instagram and Facebook, sending emails to all stakeholders on the project email list, leveraging Hawaiian Electric's customer communication email system, and publishing a blog post and e-newsletter.

Power Up received 6,334 visits from 5,385 unique visitors, primarily on mobile devices. The campaign was extremely successful, resulting in a lot of visitors, extended time spent on the page (just under 2 minutes), and more than 500 comments.

Figure 4-13 depicts a Power Up Facebook ad. Viewers could click the ad to visit the REZ maps and share their input. See Appendix A for additional copies of the social media ads and information about their reach, as well as copies of the email to stakeholders and e-newsletter to all project subscribers.

Figure 4-13. Social media ad to promote the opportunity to provide input on the renewable energy zones

We also took the REZ maps on the road, soliciting in-person feedback at the public events detailed above, including local fairs and festivals, and community workshops. At these events, we asked participants to place dots on the maps, representing areas of opportunities (green dots) and challenges (yellow dots). Figure 4-14 displays the sticker-dot activity from Maui community workshops in fall 2022.

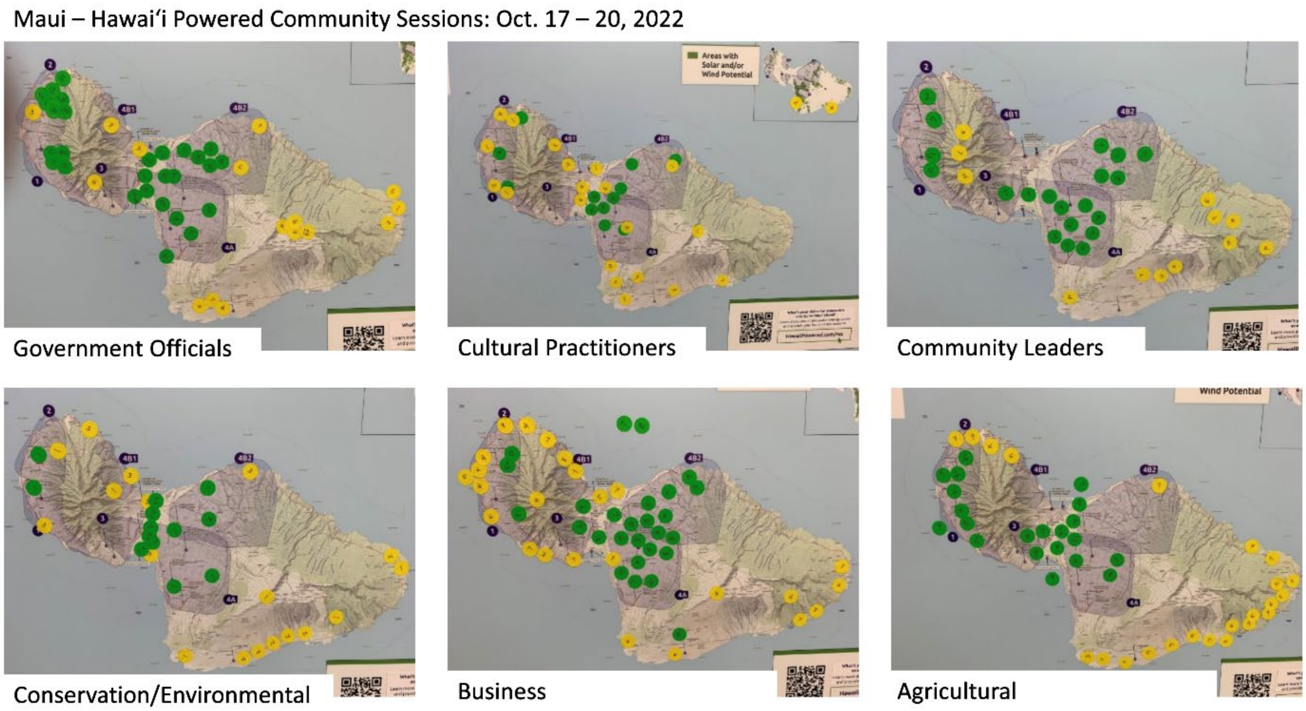


Figure 4-14. Participants at Maui community workshops, fall 2022, placed stickers representing opportunities and challenges within renewable energy zones

We received more than 500 comments on the online and in-person maps. We sorted comments into categories that correspond to key considerations in Integrated Grid Planning: time, affordability, community, land use, and resilience and reliability. See Appendix A for a record of all public comments posted to the REZ interactive maps.

We will consider the comments we received as we work with communities and developers to identify opportunities for future renewable energy projects. See Section 10 for additional discussion on public input as it relates to energy equity.

5. Today's Planning Environment

Since we began the Integrated Grid Planning process in 2018, global and local environmental factors have significantly changed. During 2020, we saw dramatic decreases in electricity usage impacting the operations of our system; in 2022, we started to see recovery to pre-pandemic levels.

Inflation and tight supply chains have plagued progress on renewable energy projects and access to foundational grid equipment. This has caused upwards of 30% increased cost for solar and battery energy storage equipment and short supply of skilled labor. Oil prices spiked in part because of the Russia-Ukraine conflict, resulting in an increase of electricity rates.

Customers continue to affirm through our public engagement that reliability and affordability are most important to them. Intertwined are energy justice and equity issues as certain customers are being left behind, creating a clean energy divide.

Our grid planning is guided by laws and policies enacted by the Hawai'i State legislature, along with the multitude of interrelated proceedings before the Public Utilities Commission. Hawai'i continues to lead the nation in climate and environmental policies, particularly in the electricity sector. Overarching State policies that guide our grid planning include 100% renewable energy by 2045 and statewide greenhouse gas reductions of 50% by 2030 and net negative by 2045 compared to 2005 levels.

5.1 Hawai'i Energy Policy

In 2008, a memorandum of understanding between the State of Hawai'i and DOE launched the Hawaii Clean Energy Initiative, which laid out the foundational elements to achieving Hawai'i's clean energy future. It envisioned that 60% to 70% of future energy needs would be provided by renewable energy, including energy efficiency. Then, in 2014, a re-commitment to the Hawaii Clean Energy Initiative blazed the pathway for the nation's first ever 100% renewable portfolio standard by 2045. The memorandum of understanding between Hawai'i and DOE set forth several key goals:

- To define the structural transformation that will need to occur to transition Hawai'i to a clean energy–dominated economy
- To demonstrate and foster innovation in the use of clean energy technologies, financing methodologies, and enabling policies designed to accelerate social, economic, and political acceptance of a clean energy–dominated economy
- To create opportunity at all levels of society that ensures widespread distribution of the

benefits resulting from the transition to a clean, sustainable energy state

- To establish an "open source" learning model for others seeking to achieve similar goals
- To build the workforce with crosscutting skills to enable and support a clean energy economy

Table 5-1 summarizes the key energy policies enacted by the legislature over the past 15 years, which has led to significant progress in shaping Hawai'i's sustainable energy future. The sum of these policies are considered in our planning as described in this report.

Table 5-1. Key State Policies and Legislation That Drive Energy Planning

Sector	Strategy	State Policy
Electricity	Clean electricity standard Performance incentives	Act 155 (SLH 2009) set an RPS target of 25% by 2020 and 40% by 2030. Act 97 (SLH 2015) modified the RPS to 70% by 2040 and 100% by 2045. Act 5 (SLH 2018) initiated the performance-based regulation proceeding, to establish performance incentives and penalties to accomplish State policy goals (e.g., accelerated RPS achievement).
Climate	Statewide decarbonization Climate emergency	Act 15 (SLH 2018) set a target to sequester more atmospheric carbon and greenhouse gases than the state produces no later than 2045, which was furthered in 2022 by Act 238 to set a target to reduce statewide emissions by 50% by 2030 compared to 2005 levels. Act 23 (SLH 2020) ceased coal burning for electricity operations by 12/31/2022. This led to the closure of the AES coal plant in September 2022. Senate Concurrent Resolution 44 (2021) declaring a climate emergency and requesting statewide collaboration toward an immediate just transition to restore a safe climate.
On-road transportation	Light-duty zero-emissions vehicles (ZEVs)	Act 74 (SLH 2021) Plan and coordinate vehicle acquisition to meet the following clean ground transportation goals: (1) 100% of passenger vehicles in the State's fleet shall be ZEVs by 12/31/2030 and (2) 100% of light-duty vehicles in the State's fleet shall be ZEVs by 12/31/2035.
Buildings	Building electrification Building codes/ appliance standards EE programs DER resources	Act 99 (SLH 2015) set a goal for the University of Hawai'i to achieve net-zero energy usage by 2035. Act 176 (SLH 2016) set a goal for the Hawai'i Department of Education to achieve net-zero energy usage by 2035. Act 204 (SLH 2008) required a solar water heater for all new single-family dwellings. State Building Code Council establishing statewide adoption of 2018 International Energy Conservation Code (IECC) for residential and commercial buildings. Act 141 (SLH 2019) established minimum appliance efficiency standards. Act 155 (SLH 2009) established an EE portfolio standard of 4,300 GWh statewide reduction by 2030. Act 100 (SLH 2015) established a CBRE program.
Resilience	Microgrids	2018 Act 200 (SLH 2019) encouraged the development of the microgrid services, which led to Public Utilities Commission approval of Hawaiian Electric Rule 30.
Equity	Energy equity	Senate Concurrent Resolution 48 (2022) requested the Public Utilities Commission to consider efforts to mitigate high energy burdens for LMI customers and integrate energy equity across its work.

Each county in Hawai'i also has or is in the process of developing sustainability plans in alignment with State policy. For example, the City and County of Honolulu will transition its vehicle and bus fleet to electric as required by Ordinance 20-47. The Department of Transportation Services now has 17 electric buses (eBuses) in service and has installed bus charging equipment to kick-start TheBus transition to 100% electric. It has also stated a goal of 45% reduction in targeted greenhouse gas emissions by 2025 relative to 2015.

5.2 Federal Policies

At the federal level, the Biden Administration has set forth the following climate goals, which are consistent with State policies:

- Reducing U.S. greenhouse gas emissions 50%–52% below 2005 levels in 2030
- Reaching 100% carbon pollution–free electricity by 2035
- Achieving a net-zero emissions economy by 2050
- Delivering 40% of the benefits from federal investments in climate and clean energy to disadvantaged communities

The U.S. Department of Defense is our largest customer, and all branches of the military are represented in our service territory, highlighting the importance of a reliable and resilient electric system in support of the national defense and the Indo-Pacific region. The U.S. Army, Navy, and Marines have set forth climate strategies. The Army Climate Strategy seeks to achieve 50% reduction in Army net greenhouse gas pollution by 2030 compared to 2005 levels; attain net-zero emissions by 2050; install a microgrid on every installation by 2035; provide 100% carbon pollution–free electricity for Army installations by 2030; and electrify light-duty, non-tactical, and tactical vehicles. Similarly, the Department of Navy Climate Action 2030 plan seeks to reduce greenhouse gases by 65% by 2030 from 2008 levels, provide 100% carbon pollution–free electricity by 2030, with half locally supplied, and acquire 100% zero-emissions vehicles (ZEVs) by 2035.

5.2.1 Bipartisan Infrastructure Law and Inflation Reduction Act

In 2022, the U.S. Congress enacted two bills in support of the Biden Administration's goals that will significantly impact the nation's clean energy transition. We along with the State are aggressively pursuing federal funding to ease the financial burden of the clean energy transition on Hawai'i's residents.

Collectively, the Infrastructure Investment and Jobs Act and Inflation Reduction Act represent a fleeting opportunity for the State and our customers and communities to obtain federal funding to advance sustainability and resilience goals. We have identified a portfolio of projects that have the highest impact and chance for success—grid resilience, grid flexibility and modernization, electrification of transportation, and middle mile broadband. The Inflation Reduction Act also provides investment tax credits for standalone storage, which could benefit the Waena and Keahole battery energy storage projects that were selected through the Stage 2 competitive procurement.

Our middle mile broadband application is pending and awaiting award notice, which could come with up to a 69% federal match in funding. In December 2022, we submitted two concept papers to DOE and in February 2023 we received formal notice encouraging submission for a full application for grid resilience and grid flexibility and modernization with a potential for a 50% match in federal funding. These awards could reduce customer costs for our grid modernization and climate adaptation and transmission and distribution resilience programs.

5.3 Interrelated Dockets

Integrated Grid Planning and Performance-Based Regulation proceedings are foundational to implementing State energy policy and achieving its goals. In combination, these two proceedings shape how we will continue to serve Hawai'i with clean, affordable, and reliable energy.

A multitude of ongoing proceedings are currently before the Public Utilities Commission, in collaboration with Hawai'i energy stakeholders, intended to carry out the legislature's policies. The Integrated Grid Plan is foundational to these interrelated proceedings because it sets forth a well vetted common set of assumptions and lays out future pathways as we move toward our decarbonization goals. Having Public Utilities Commission–approved Integrated Grid Plan and priorities set under Performance-Based Regulation (along with a stable financial structure for the utility) allows other dockets to advance more efficiently by reducing protracted discussions on forward-looking assumptions and resource plans. The Integrated Grid Plan sets the direction to implement other initiatives and programs. Throughout this report we note where other dockets are intertwined with the Integrated Grid Plan. The Stakeholder Council discussed the importance of maintaining the interrelationship of the following dockets.

Performance-Based Regulation (Docket 2018-0088). A docket to reform Hawai'i's regulatory framework through regulatory mechanisms focused on utility performance and alignment with public policy goals.

Performance-Based Regulation and the Integrated Grid Plan build upon one another, including but not limited to performance incentives for RPS achievement, interconnection of rooftop solar and large-scale resources, fossil-fuel cost risk sharing, generation reliability, and Extraordinary Project Recovery Mechanism (EPRM) to enable needed investments to transition the grid we need. Priorities outlined in Performance-Based Regulation are areas that the Integrated Grid Plan seeks to address and may also drive future adjustments to Performance-Based Regulation such that the execution of our near- and long-term plans are aligned with Performance-Based Regulation priorities that ultimately accomplish our decarbonization goals.

Community-Based Renewable Energy Program (Docket 2015-0389). A docket to create a market-based framework that enables renewable energy opportunities for customers who are unable to have on-site distributed generation.

CBRE resources acquired through CBRE Phase 1 and assumptions to fulfill the Phase 2 program capacity are part of the planned resources in our plans. The CBRE resources in our plans play an important role in providing essential grid services under a renewable dispatchable PPA while simultaneously expanding customer access to renewable energy for those without a roof to install solar, LMI customers, or renters.

Competitive Bidding Process to Acquire Dispatchable and Renewable Generation (Docket 2017-0352). A repository docket for RFP, PPAs, and other documents related to the procurement of large-scale renewable resources and grid services.

Since the power supply improvement plans in December 2016 we have issued procurements for large-scale renewable dispatchable generation through three stages of procurements, known as Stages 1, 2, and 3. Through Stages 1 and 2, solar paired with battery energy storage and standalone energy storage have been the lowest-cost technologies awarded contracts. Many of these projects have been plagued by supply-chain and other issues caused by the pandemic. A Stage

3 procurement is currently in progress to procure additional renewable energy and also seeks firm renewable generation to enable retirement of existing fossil fuel–based generators. The Stage 3 renewable energy targets are a part of the planned resources in our analysis.

Microgrid Services Tariff (Docket 2018-0163). A docket to establish a greater structure around microgrid interconnection(s) and the value of services provided by microgrids through a microgrid services tariff.

Through this proceeding, we worked with stakeholders to develop a microgrid services tariff that enables communities to build microgrids for added resilience. Enhancements to enable more participation in microgrids are expected to continue in Phase 2 of the proceeding. However, in parallel we have worked with the Resilience Working Group and the Energy Transition Initiative Partnership Project to identify and prioritize critical and vulnerable customers. As discussed in Section 7, microgrids are part of our tools to enhance grid resilience.

Electrification of Transportation Roadmap (Docket 2018-0135). A docket to evaluate the state of EV technology and the EV market in Hawaiʻi and Hawaiian Electric's near- and long-term priorities for electrifying the transportation sector.

As part of the Integrated Grid Planning forecasts and assumptions we have developed EV adoption forecasts with managed charging load usage to determine the benefits of workplace and daytime charging. We also describe the potential distribution infrastructure needed to integrate electrification onto our grids. See Sections 8 and 11.

Distributed Energy Resource Policies (Docket 2019-0323). A docket to investigate technical, economic, and policy issues associated with distributed energy resources and further develop a portfolio of broader DER customer options.

As discussed in Section 6, we have incorporated future DER programs and time-of-use (TOU) rates, including managed EV charging, as part of our forecasted electric load.

An important component of our resource portfolio to date and into the future are customer resources, including private rooftop solar, battery energy storage, electric vehicles, and energy efficiency. These customer technologies are prominently discussed throughout this report.

Investigation of Energy Equity (Docket 2022-0250). A docket to investigate energy equity to further State policy goals, improve energy affordability, reduce energy burdens for vulnerable customers, and ensure that the benefits of the renewable energy transition are equitably distributed, among other things.

We are keen on addressing energy equity, as discussed in Section 10, as we strive to make the transition to our decarbonized future as equitable as possible. In our engagement with customers, we have heard firsthand from communities burdened by hosting energy infrastructure and projects. We have also heard from customers that affordability is their highest consideration.

6. Data Collection

In the data collection phase of the process we engaged with numerous Working Groups made up of industry leaders, economists, and engineers along with our Stakeholder Council and Technical Advisory Panel to collect data to forecast how customers will choose to consume and produce energy in the future. This includes evaluating the propensity for customers to adopt new technologies like private rooftop solar, battery energy storage, electric vehicles, and energy-efficient appliances, among other key inputs and assumptions.

These forecasts allow us to develop scenarios and pathways to understand how energy needs will change over a range of possible futures. For example, we will use a high and low adoption rate of customer technologies to determine the lowest-cost way to deliver renewable energy to customers.

We aim to create the grid as a platform to support both active and passive customers of the grid—for those who desire traditional electric service or for those who want greater control over their energy use. The choices customers make in adopting technologies and the ways they choose to use electricity influence how many large-scale projects we must pursue. We used these forecasts in our analysis to lay out pathways for a grid that works for all.

See Appendix B for more details on the forecasts, assumptions, and methodologies used as part of the Data Collection phase and overall planning process.

6.1 Load Forecast Methodology and Data

The customer load forecast is a key assumption for the planning models that provide the energy requirements and peak demands that must be served by the grid through the planning horizon. Based on the recommendation of the Technical Advisory Panel we developed a High electricity demand and Low electricity demand projection to test how the cost and portfolio of resources would change for a range of peak demand and load profiles. The scenarios described in Section 6.8 provide a range of forecasts to plan for uncertainties in adoption of customer technologies, which ultimately drive the amount of electricity we forecast our customers will consume.

We developed forecasts for each of the five islands and began with the development of the energy forecast (i.e., sales forecast) by rate class (residential, small, medium, and large commercial and street lighting) and by layer (underlying load forecast and adjusting layers: energy efficiency, distributed energy resources, electrification of transportation, and time-of-use rate load shift).

The underlying load forecast is driven primarily by the economy, weather, electricity price, and known adjustments to large customer loads and is informed by historical data, structural changes[1], and historical and future disruptions. The impacts of energy efficiency, distributed energy resources, primarily private rooftop solar with and without storage (i.e., batteries), and electrification of transportation (light-duty electric vehicles and electric buses, collectively "EoT") were layered onto the underlying sales outlook to develop the electric sales forecast at the customer level. Load shifting in response to time-of-use rates was also included as a forecast layer. Because we assumed a net-zero load shift (i.e., load reductions during the peak period are offset by load increases during other periods), there is impact to the peak forecasts, but no impact to the sales forecasts. The *March 2022 Inputs and Assumptions Report* provides additional descriptions of the load forecast assumptions and methodologies.

The modeling process to identify grid needs relies on a set of forecast assumptions to define what we believe the future system could look like. Many of these assumptions have been developed by the forecast assumptions, the solution evaluation and optimization, and the Stakeholder Technical Working Groups.

6.2 Distributed Energy Resources Forecasts

The DER forecast layer, mainly private rooftop solar and battery energy storage systems (BESSs), includes new additions of rooftop solar capacity by island, rate class and program, and projected sales impact from these additions. We used current/near-term pending and approved DER applications and the long-term economic payback of customers installing a private rooftop solar system to develop the forecast.

At the time forecasts were developed, advanced rate designs (ARDs) and long-term DER programs were in the process of being finalized. We assumed that the future customer solar programs compensate for export that is aligned with system needs and allow for controllability during system emergencies. The export compensation and tariff structure for future customer solar programs were based on the Standard DER Tariff for all islands that we proposed in the DER docket[2]. On January 25, 2022, the Public Utilities Commission issued Order 38196 establishing the framework for the Smart DER Tariff[3]. While export compensation, incentives, and tariff structure for the Smart DER Tariff are awaiting final Public Utilities Commission approval, anecdotal conversations with industry experts, customer application, and permit data show that customers are choosing to use battery storage to shift their generation to offset their own load rather than exporting to the grid during the daytime.

In addition, for O'ahu and Maui, we incorporated the current Battery Bonus program[4], and assumed new DER-provided grid services (i.e., bring-your-own-device programs) as part of a long-term DER program. Consistent with the Battery Bonus program, incentives would be paid based on performance and commitment of the customer resource. We assumed customers participating in Battery Bonus export at the battery system's rated capacity (kilowatts [kW]) (if energy is available) for a 2-hour duration during the evening peak window

[1] Structural changes include the addition of new resort loads or new air conditioning loads that have a persistent impact on the forecast.

[2] *See* Hawaiian Electric's DER Program Track Final Proposal filed on May 3, 2021, in Docket 2019-0323, Instituting a Proceeding to Investigate Distributed Energy Resource Policies pertaining to the Hawaiian Electric Companies.

[3] 3 See Order 38196 issued on January 25, 2022, in Docket 2019-0323, Instituting a Proceeding to Investigate Distributed Energy Resource Policies pertaining to the Hawaiian Electric Companies.

[4] *See* Order 37816 issued on June 8, 2021, in Docket 2019-0323, Instituting a Proceeding to Investigate Distributed Energy Resource Policies pertaining to the Hawaiian Electric Companies.

each day. Future retrofits for net energy metering customers assumed both an addition of a battery system, 5 kW/13.5 kWh, and an increase in photovoltaic (PV) capacity, 5 kW[5]. The described methodology and forecast sensitivities appropriately capture the Public Utilities Commission–approved Battery Bonus program targeting 50 MW on O'ahu and 15 MW on Maui.

NREL 2021 Annual Technology Baseline (ATB) forecasts PV and BESS costs to continue to decline and with the rollout of a broad opt-out time-of-use rate, we assumed that most future systems under the future Smart DER Tariff will be paired with storage. Furthermore, the rollout of a broad opt-out time-of-use rate would increase the incentive to pair future systems with storage.

Table 6-1 and Table 6-2 summarize the private rooftop solar and energy storage forecasts by island used in the Base electricity demand scenario.

Table 6-1. Cumulative Distributed PV Capacity (kW)

Year	O'ahu	Hawai'i Island	Maui	Moloka'i	Lāna'i	Consolidated
kW	A	B	C	D	E	F =A + B + C + D +E
2025	723,234	138,801	158,260	3,200	1,050	1,024,545
2030	830,974	164,392	185,501	3,696	1,356	1,185,919
2040	993,411	209,179	227,968	4,476	1,888	1,436,922
2045	1,053,934	227,449	242,917	4,768	2,085	1,531,153
2050	1,104,843	243,258	255,327	4,952	2,266	1,610,646

Table 6-2. Cumulative Distributed BESS Capacity (kWh)

Year	O'ahu	Hawai'i Island	Maui	Moloka'i	Lāna'i	Consolidated
kWh	A	B	C	D	E	F =A + B + C + D +E
2025	317,754	84,230	128,263	1,348	515	532,110
2030	493,412	126,316	179,030	2,308	875	801,941
2040	756,521	196,611	254,943	3,976	1,550	1,213,601
2045	848,456	224,301	282,258	4,588	1,829	1,361,432
2050	923,096	247,272	303,603	5,068	2,072	1,481,111

6.2.1 High and Low Bookend Sensitivities

High and low adoption rates were developed to capture uncertainties associated with the base assumptions. Under these sensitivities, we modified assumptions to the addressable market, incentive structure, and technology costs.

Under the High Sensitivity, we assumed an extension of the federal investment tax credit through 2032, with residential investment tax credits ending and commercial investment tax credits settling at 10% in 2033. These assumptions closely align to the final provisions under the Inflation Reduction Act, signed into law on August 16, 2022. The long-term upfront incentives for a future grid services program on all islands were also increased to $500/kW for the high DER forecast.

NREL 2021 ATB Advanced Scenario cost curves for residential and commercial PV and battery systems were selected for the High DER sensitivity

[5] Order 37816 permits existing PV customers to add up to 5 kW of additional PV generation capacity.

forecast. The ATB Advanced Scenario assumes a rapid advancement in technology innovation and manufacturing at levels above and beyond the current market, resulting in lower projected costs compared to the ATB Moderate Scenario.

The Low DER sensitivity (compared to the Base) assumes a smaller addressable market, no long-term export program, and no additional incentives for distributed energy resources.

The No State Income Tax Credit (ITC) sensitivity was modeled assuming a 0% State ITC starting in 2022, resulting in lower DER uptake compared to the Base forecast. In both sensitivities, DER system costs and tax credit assumptions were updated similarly to the current Base scenario. Figure 6-1 illustrates the revised DER forecasts for O'ahu.

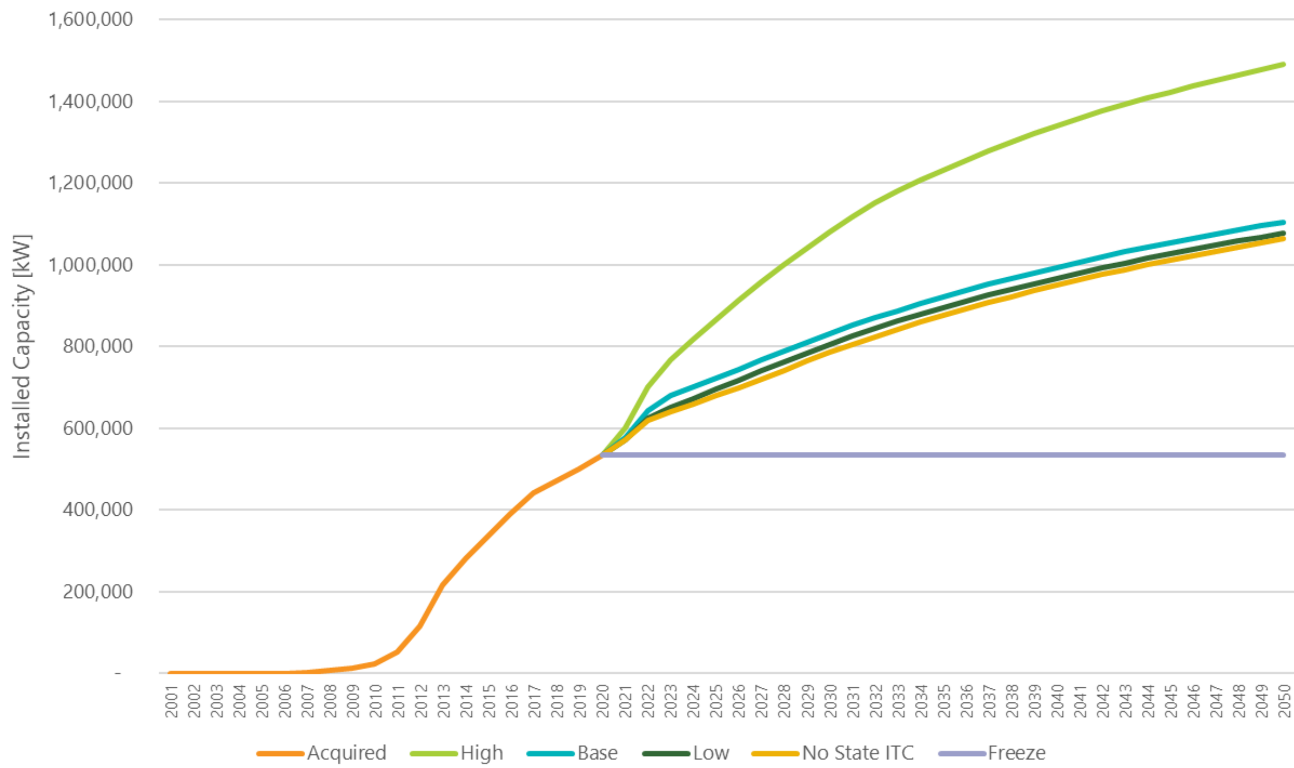


Figure 6-1. O'ahu DER bookend sensitivities

6.3 Advanced Rate Design Impacts

The advanced rate design discussed in the DER docket includes the implementation of default time-of-use rates, with an option to return to the prior rate schedule, applicable also to all new DER customers. Consistent with advanced rate design, each customer that adopts private rooftop solar and energy storage and/or electric vehicles under managed charging scenarios is effectively shaping their consumption aligned with a time-of-use rate. For example, DER customers would charge their energy storage system with rooftop solar during the day and discharge the energy in the evening. This load shifting is captured in the forecasted battery energy storage profiles. Because these kinds of DER customers are already assumed to be shifting their load in a manner consistent with that encouraged by proposed time-of-use rates, minimal to no additional load shift would be expected in response to time-of-use rates for these customers. The managed charging forecast profiles for EV customers reflect customers charging electric vehicles during the day in response to time-of use rates.

We evaluated time-of-use load shifting impact for non-DER and non-EV customers. Table 6-3 was used to develop time-of-use load shift scenarios for residential customers.

Table 6-3. Summary of Assumptions Used to Develop Residential TOU Load Shift Sensitivities

Input	Low	Base	High
Rates	Hawaiian Electric Final ARD Proposal	Hawaiian Electric Final ARD Proposal	DER Parties Final ARD Proposal
Residential customer pool	All non-DER residential customers = residential forecast minus High DER Sch-R forecast	All non-DER residential customers = residential forecast minus Base DER Sch-R forecast	All non-DER residential customers = residential forecast minus Base DER Sch-R forecast
AMI rollout	100% by 2025, straight line from current deployment to 2025	100% by 2025, straight line from current deployment to 2025	100% by 2025, straight line from current deployment to 2025
TOU rollout	Default rate for AMI meters ramps up from 2022 to 2026	Default rate for AMI meters ramps up from 2022 to 2026	Default rate for AMI meters ramps up from 2022 to 2026
Load shift method	Net-zero load shift	Net-zero load shift	Net-zero load shift
TOU opt-out rate (%)	25%	10%	10%
Price elasticity	-0.045	-0.070	-0.070

On October 31, 2022, the Public Utilities Commission issued Decision and Order 38680 under Docket 2019-0323, establishing a framework for the determination of the new time-of-use rates. Under the order, the Public Utilities Commission directed the new time-of-use energy charge to have a price ratio of 1:2:3 for the daytime, overnight, and evening peak periods. While the Public Utilities Commission's order came after the establishment of the forecast we assumed a 1:2:3 ratio in the time-of-use High sensitivity forecast. We will also conduct a study on the customers assigned to the time-of-use rates pilot to understand the impacts and effectiveness of the rate design. We will consider how to incorporate findings from the study into future Integrated Grid Planning cycles. For this cycle, we believe that the High and Low bookend scenario reflects significant load shaping and generally captures unanticipated impacts of rate design changes or behavioral changes for customers who do not have an electric vehicle or rooftop solar and energy storage.

The uncertainty of these and other future changes in customer trends are what the High and Low bookends are intended to capture such that any changes that may occur, that impact the net demand, would fall within the bookends.

6.4 Electrification of Buildings and Energy Efficiency

The EE layer is based on projections from the July 2020 State of Hawaii Market Potential Study prepared by Applied Energy Group (AEG) and sponsored by the Hawaiʻi Public Utilities

Commission.[6] The market potential study considered customer segmentation, technologies and measures, building codes, and appliance standards as well as progress toward achieving the Energy Efficiency Portfolio Standards. The study included technical, economic, and achievable EE potentials. AEG reclassified certain market segments to different customer classes to align with how we forecast sales.

6.4.1 High and Low Bookend Sensitivities

An achievable business-as-usual (BAU) EE potential forecast by island and sector covering the years 2020 through 2045 was provided in February 2020 to use as our Base forecast. The business-as-usual potential forecast represented savings from realistic customer adoption of EE measures through future interventions that were similar in nature to existing interventions. In addition to the business-as-usual forecast, AEG provided a codes and standards (C&S) forecast and an Achievable: High forecast. The Achievable: High potential forecast assumed higher levels of savings and participation through expanded programs, new codes and standards, and market transformation.

The additional EE potentials provided by AEG allowed for the creation of various forecast sensitivities. As a result, we developed three different sensitivities, Low, High, and Freeze. Table 6-4 and Figure 6-2 summarize the EE sensitivities and their forecasted annual sales (GWh).

Table 6-4. Energy Efficiency Bookend Sensitivities

Low	Base	High	Freeze
BAU (Reduced by 25%)+ C&S	BAU + C&S	Achievable: High + C&S	Forecasted BAU capacity fixed at 2021 Base forecast + C&S

[6]*See* https://puc.hawaii.gov/wp-content/uploads/2021/02/Hawaii-2020-Market-Potential-Study-Final-Report.pdf

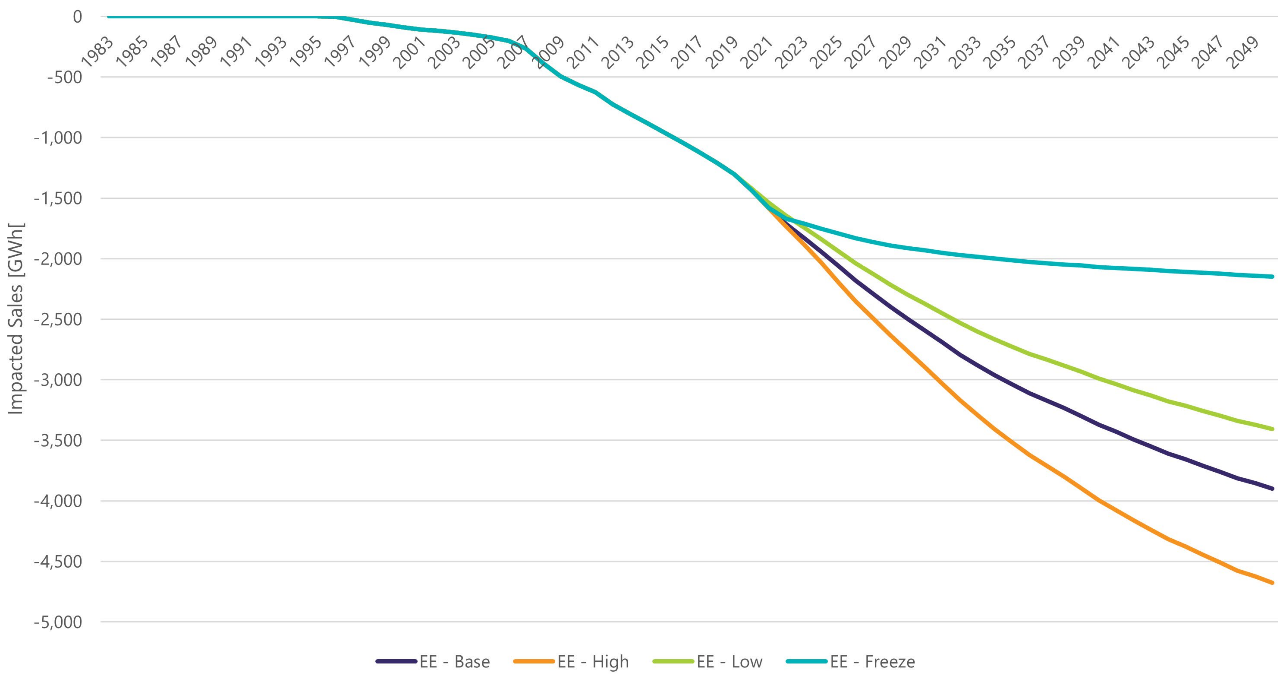


Figure 6-2. O'ahu energy efficiency annual sales forecast impact sensitivities

6.4.2 Energy Efficiency Supply Curve Bundles

EE supply curve bundles were developed to determine the optimal amount of EE measures compared to the assumed forecasted energy efficiency using the results of the market potential study that AEG performed on behalf of the Public Utilities Commission. These supply curves were used in the EE supply curve sensitivity discussed in Section 11.1.3.

6.4.2.1 Energy Efficiency Supply Curve Development Methodology

The supply curves were developed to treat energy efficiency as an available resource to be selected based on its cost and value. This required creating a new level of EE potential, referred to as "achievable technical," before applying any screens for cost-effectiveness.

Peak Impacts

Each EE measure has an island-specific load shape, which was created during the potential study process. By taking the annual savings calculated from the market potential study and distributing it across this shape, impacts in each hour of the year can be calculated for each measure shape. The relative "peakiness" of each measure was considered by comparing its impacts during peak hours to a flat shape. Peak impacts refer to impacts on the average weekday evening peak hour (between 6 and 8 p.m.) and are calculated as the average impacts during such hours.

Figure 6-3 shows the average impacts of all measures within each classification using O'ahu as an example, based on cumulative potential in 2030. As expected, peak-focused measure impacts are strongly concentrated in the weekday evening hours, whereas "other" measure impacts are much flatter.

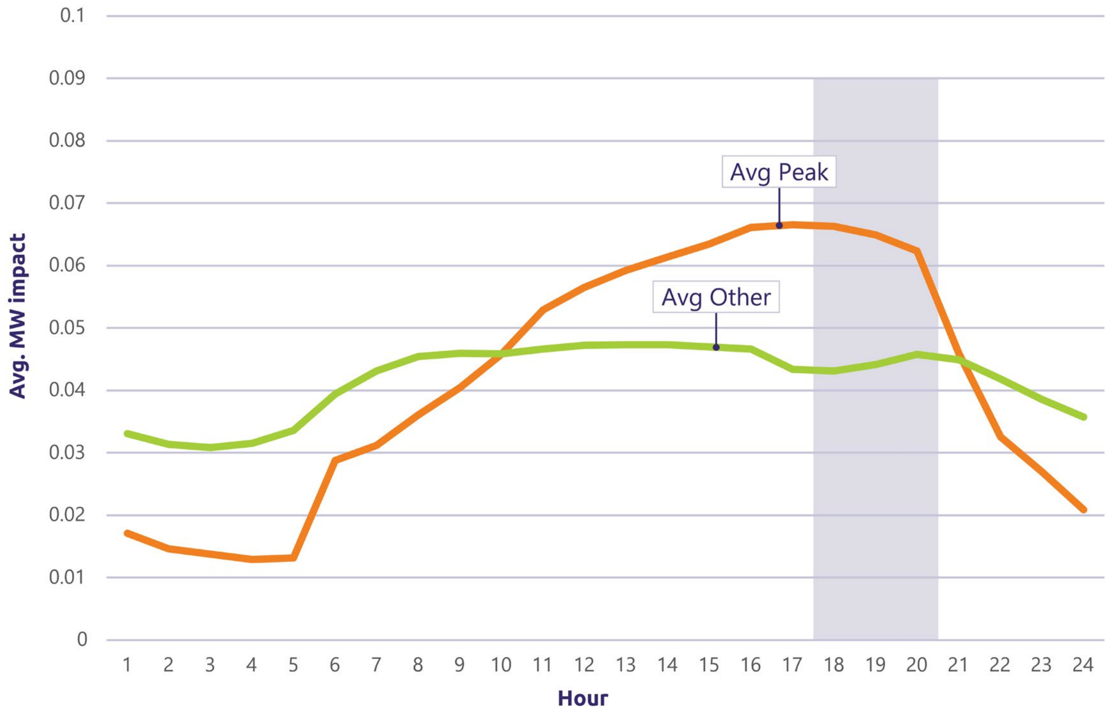


Figure 6-3. Averaged weekday impacts by measure classification, cumulative in 2030 (peak vs. other, O'ahu)

6.4.2.2 Analysis Results

Figure 6-4 shows the incremental energy savings potential for each bundle over the forecast period. The sharp increase in savings in 2025 coincides with an increase in commercial linear lighting installations because of equipment turnover in the potential study modeling. These annual savings values do not include reinstallation of measures that were previously incentivized and may have expired. While these measures will need to be reacquired in later years, they will not increase the total cumulative potential, so those reacquisition savings are excluded from this perspective.

There could be marginal additional savings at the time of reacquisition, such as if technology standards have improved in the intervening years; however, such savings would be difficult to quantify directly using the outputs of the market potential study. The modeled potential without reacquisitions is a conservative estimate to avoid overstating potential.

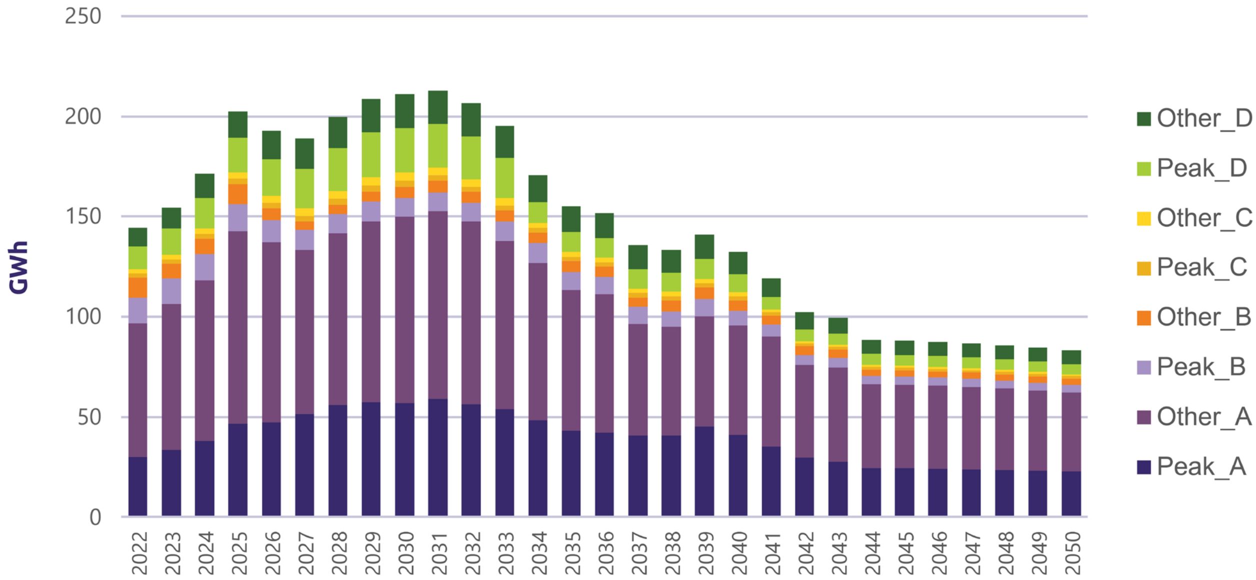


Figure 6-4. Incremental annual energy savings potential (achievable technical) by measure bundle (all islands combined)

The peak bundles are dominated by the cooling end use. The Peak A bundle, which includes the most cost-effective measures from the potential study, gets 77% of its savings from the cooling end use. The "Other" bundles are made up mainly of water heating, lighting, and appliance measures, which tend to have flatter or even morning-focused shapes.

6.5 Electrification of Transportation

The EoT layer consists of impacts from the charging of light-duty electric vehicles and electric buses. A medium and heavy-duty EV forecast has been identified for inclusion for the next Integrated Grid Planning cycle.

6.5.1 Light-Duty Electric Vehicles

The light-duty EV forecast was based on an adoption model developed by Integral Analytics, Inc. as described in Appendix E of the EoT Roadmap[7] to arrive at EV saturations of total light-duty vehicles by year for each island. Historical data for LDV registrations were provided by the State Department of Business, Economic Development, and Tourism and reported at the county level. The development of the EV forecast used the EV saturation by island to arrive at the number of light-duty electric vehicles.[8] Although EV saturations were not specifically consistent with carbon neutrality in Hawai'i by 2045, they are consistent with county goals for converting their fleets to 100% zero-emissions vehicles by 2035.

[7] *See* https://www.hawaiianelectric.com/documents/clean_energy_hawaii/electrification_of_transportation/201803_eot_roadmap.pdf

[8] *See* https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/forecast_assumptions/PUC-HECO-IR-1_att_8_electric_vehicles.xlsx

6.5.2 Electric Buses

The eBus forecast was based on discussions with several bus operators throughout Honolulu, Hawai'i, and Maui Counties. Route information and schedules for weekdays, weekends, and holidays were used to estimate the miles traveled for each bus operator. For each island, the total sales impact for each bus operator was applied to the rate schedule on which each bus operator was serviced.

6.5.3 High and Low Bookend Sensitivities

Three additional light-duty EV forecast sensitivities (Low, High, and Freeze) were developed using varying adoption saturation curves. At the June 17, 2021, Stakeholder Technical Working Group meeting, Blue Planet presented its suggested sensitivity representing a policy of 100% zero-emissions vehicles by 2045 in the Faster Technology Adoption scenario, a change from the previously presented high saturation curve. Following that meeting, we developed a high customer adoption forecast based on the Transcending Oil Report prepared by the Rhodium Group in 2018. The Transcending Oil Report study considered vehicle scrappage rates and the transition rate of vehicle sales to fully electric. The study estimated that all vehicle sales by 2030 would need to be electric to reach 100% EV stock by 2045.[9] A freeze sensitivity was also developed, assuming no new additional electric vehicles above the Base forecast after 2021. Table 6-5 and Figure 6-5 summarize the light-duty EV sensitivities and their forecasted annual sales (GWh).

Table 6-5. Electric Vehicle Forecast Sensitivities

Low	Base	High	Freeze
Low adoption saturation	Market forecast	100% of ZEV by 2045	Forecasted EV counts fixed at 2021 Base forecast

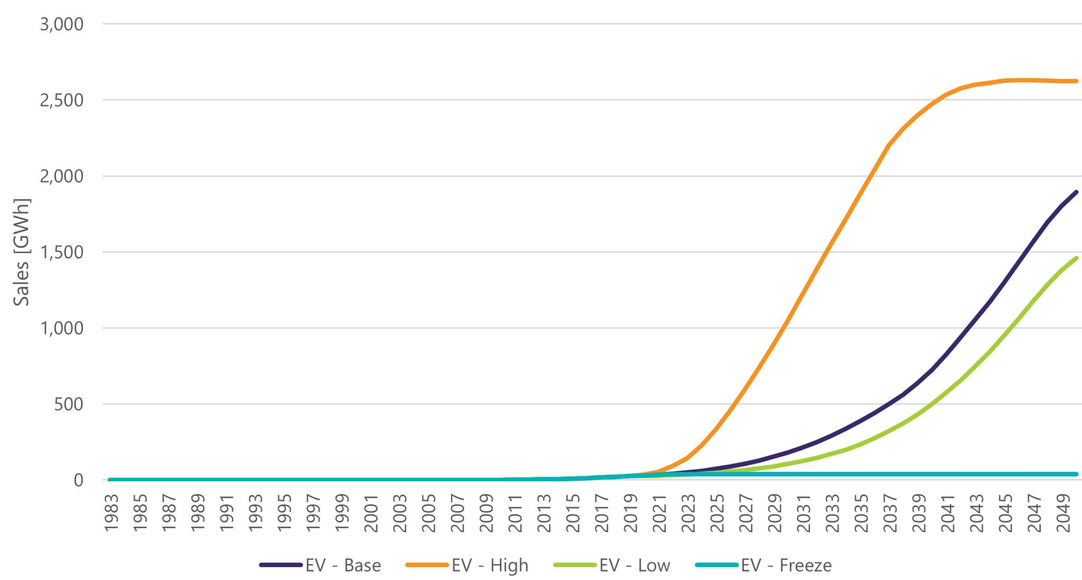


Figure 6-5. O'ahu EV annual sales forecast sensitivities

[9] See Transcending Oil Report by Rhodium Group available at: https://rhg.com/wp-content/uploads/2018/04/rhodium_transcendingoil_final_report_4-18-2018-final.pdf

6.5.4 Managed Electric Vehicle Charging

The managed EV charging profile considers EV driver response to time-of-use rates that were proposed for each island in the EV pilot programs in Docket 2020-0152. A linear optimization was used to model drivers who shift their usage to the daytime to reduce their electricity bill as much as possible, while still retaining enough state of charge to meet their underlying driving profiles. The underlying trip data are the same so the managed and unmanaged charging have the same annual loads. The average managed EV charging profile for select years is provided for O'ahu in Figure 6-6.

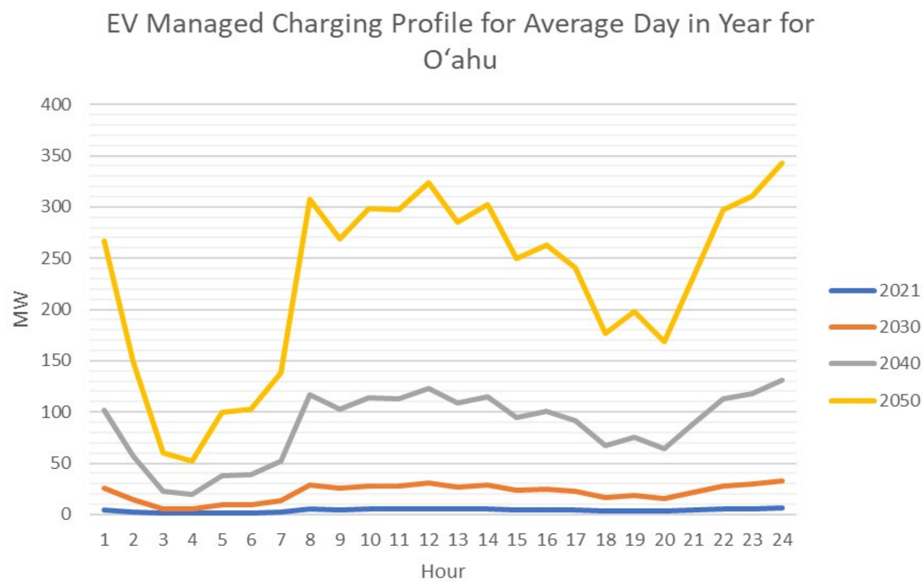


Figure 6-6. Average managed EV charging profile for O'ahu

6.6 Sales Forecasts

Once all the layers are developed for each island, they are added together to arrive at the sales forecast at the customer level by island as shown in Table 6-6 through Table 6-10.

Table 6-6. O'ahu Sales Forecast

Year	Underlying	Distributed Energy Resources (PV and BESS)	Energy Efficiency	Electric Vehicles	Customer Level Sales Forecast
GWh	A	B	C	D	E = A + B + C + D
2025	9,456	(1,255)	(1,887)	92	6,407
2030	10,133	(1,415)	(2,307)	221	6,632
2040	11,110	(1,642)	(2,917)	789	7,341
2045	11,499	(1,707)	(3,142)	1,366	8,016
2050	11,905	(1,756)	(3,332)	1,964	8,781

Table 6-7. Hawai'i Island Sales Forecast

Year	Underlying	Distributed Energy Resources (PV and BESS)	Energy Efficiency	Electric Vehicles	Customer Level Sales Forecast
GWh	A	B	C	D	E = A + B + C + D
2025	1,471	(228)	(268)	10	986
2030	1,535	(263)	(345)	39	967
2040	1,634	(325)	(461)	172	1,020
2045	1,670	(346)	(501)	288	1,110
2050	1,708	(364)	(535)	435	1,244

Table 6-8. Maui Sales Forecast

Year	Underlying	Distributed Energy Resources (PV and BESS)	Energy Efficiency	Electric Vehicles	Customer Level Sales Forecast
GWh	A	B	C	D	E = A + B + C + D
2025	1,474	(271)	(300)	14	917
2030	1,572	(312)	(371)	56	945
2040	1,726	(374)	(473)	255	1,134
2045	1,787	(390)	(505)	357	1,248
2050	1,852	(403)	(529)	443	1,363

Table 6-9. Moloka'i Sales Forecast

Year	Underlying	Distributed Energy Resources (PV and BESS)	Energy Efficiency	Electric Vehicles	Customer Level Sales Forecast
GWh	A	B	C	D	E = A + B + C + D
2025	36.0	(5.8)	(3.1)	0.1	27.2
2030	36.4	(6.5)	(3.6)	0.3	26.6
2040	37.8	(7.7)	(4.2)	1.1	27.0
2045	38.3	(8.0)	(4.5)	2.1	27.9
2050	38.9	(8.2)	(4.7)	3.2	29.3

Table 6-10. Lāna'i Sales Forecast

Year	Underlying	Distributed Energy Resources (PV and BESS)	Energy Efficiency	Electric Vehicles	Customer Level Sales Forecast
GWh	A	B	C	D	E = A + B + C + D
2025	40.8	(1.7)	(1.6)	0.1	37.6
2030	42.2	(2.1)	(2.0)	0.2	38.2
2040	44.1	(2.9)	(2.8)	0.7	39.1
2045	44.7	(3.2)	(3.0)	1.3	39.8
2050	45.6	(3.4)	(3.3)	1.9	40.8

As part of future Integrated Grid Planning cycles, we will consider full economy-wide decarbonization scenarios and their impact on electric sales. This Integrated Grid Planning cycle focused mostly on the decarbonization of buildings, light-duty electric vehicles, and bus segments of the economy. We expect significantly higher electric loads under aggressive electrification scenarios.

6.7 Peak Forecasts

Once the sales forecast is developed by layer (underlying load, rooftop solar and energy storage, energy efficiency, and electric vehicles and buses) for each island, we convert it from a monthly sales forecast into a load forecast at the system level for each hour over the entire forecast horizon. The method converting sales to an hourly load forecast is shown in Figure 6-7. Hourly shapes from class load studies for each rate class or the total system load excluding the impact from solar are used to derive the underlying system load forecast shape. Hourly regression models are evaluated to look for relationships with explanatory variables (weather, month, day of the week, holidays) to accommodate change in the underlying shapes over time for each rate class or total system load. The hourly regression models are used to simulate shapes for the underlying forecast based on the forecast assumptions over the entire horizon. The forecasted energy for the underlying and each adjusting layer is placed under its respective future load shape then converted from the customer level to system level using a loss factor[10] as presented in the July 17, 2019[11] and March 9, 2020[12] Forecast Assumptions Working Group meetings. The result is an hourly net system load for the entire forecast period. The annual peak forecast is the highest value in each year.

Table 6-11 through Table 6-15 show peak forecasts by island.

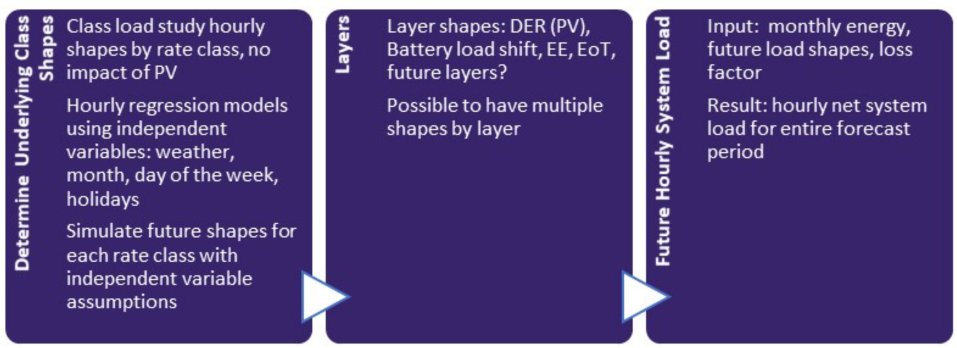


Figure 6-7. Process for converting sales forecast into an hourly demand load forecast

Table 6-11. O'ahu Peak Forecast (MW)

Year	Underlying	Distributed Energy Resources (PV and BESS)	Energy Efficiency	Electric Vehicles	TOU	Peak Forecast
MW	A	B	C	D	E	F = A + B + C + D + E
2025	1,579	(60)	(339)	16	(3)	1,193
2030	1,642	(95)	(402)	39	(5)	1,179
2040	1,736	(87)	(454)	145	(4)	1,335
2045	1,702	(43)	(452)	286	(4)	1,490
2050	1,721	(51)	(477)	473	(4)	1,661

[10] The net-to-system factor used to convert customer sales to system level load is calculated as equal to 1/(1-loss factor) and include company use. The loss factors are included below: O'ahu: 4.43%; Hawai'i: 6.76%; Maui: 5.17%; Lāna'i: 4.39%; Moloka'i: 9.07%

[11] *See* https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/forecast_assumptions/20190717_wg_fa_meeting_presentation_materials.pdf

[12] *See* https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/forecast_assumptions/20200309_wg_fa_meeting_presentation_materials.pdf

Table 6-12. Hawaiʻi Island Peak Forecast (MW)

Year	Underlying	Distributed Energy Resources (PV and BESS)	Energy Efficiency	Electric Vehicles	TOU	Peak Forecast
MW	A	B	C	D	E	F = A + B + C + D + E
2025	229.5	(10.0)	(42.6)	2.1	(1.3)	177.6
2030	236.8	(12.5)	(55.5)	8.7	(1.5)	176.0
2040	249.9	(10.8)	(84.2)	39.6	(2.2)	192.3
2045	247.2	(3.4)	(85.3)	64.5	(1.9)	221.2
2050	256.5	(3.8)	(99.6)	99.3	(2.1)	250.3

Table 6-13. Maui Peak Forecast (MW)

Year	Underlying	Distributed Energy Resources (PV and BESS)	Energy Efficiency	Electric Vehicles	TOU	Peak Forecast
MW	A	B	C	D	E	F = A + B + C + D + F
2025	245.5	(18.0)	(47.3)	3.4	(0.8)	182.7
2030	260.0	(29.2)	(58.1)	12.5	(1.2)	184.1
2040	240.1	(3.9)	(64.6)	64.5	(0.9)	235.2
2045	254.2	(4.1)	(67.7)	79.0	(0.9)	260.4
2050	259.1	(16.8)	(71.2)	112.7	(1.1)	282.8

Table 6-14. Molokaʻi Peak Forecast (MW)

Year	Underlying	Distributed Energy Resources (PV and BESS)	Energy Efficiency	Electric Vehicles	TOU	Peak Forecast
MW	A	B	C	D	E	F = A + B + C + D + E
2025	5.8	(0.1)	(0.1)	0.0	(0.0)	5.6
2030	5.7	(0.1)	(0.1)	0.1	(0.0)	5.5
2040	6.1	(0.2)	(0.2)	0.2	(0.0)	5.9
2045	6.3	(0.3)	(0.2)	0.5	(0.0)	6.3
2050	6.5	(0.3)	(0.2)	0.8	(0.0)	6.7

Table 6-15. Lānaʻi Peak Forecast (MW)

Year	Underlying	Distributed Energy Resources (PV and BESS)	Energy Efficiency	Electric Vehicles	TOU	Peak Forecast
MW	A	B	C	D	E	F = A + B + C + D + E
2025	6.5	(0.0)	(0.1)	0.0	(0.0)	6.3
2030	6.8	(0.1)	(0.2)	0.0	(0.0)	6.5
2040	7.2	(0.1)	(0.3)	0.1	(0.0)	6.9
2045	7.3	(0.2)	(0.4)	0.3	(0.0)	7.0
2050	7.5	(0.2)	(0.4)	0.4	(0.0)	7.3

6.8 Scenarios and Sensitivities

In collaboration with stakeholders, as documented in the *March 2022 Inputs and Assumptions Report*, we developed several scenarios to identify a range of potential grid needs. The scenarios test whether given uncertain futures the resource mix and direction of the lowest-cost portfolio would change. Table 6-16 describes the various scenarios we analyzed and presented in this report.

Table 6-16. List of Modeling Scenarios and Associated Forecast Assumptions

Modeling Scenario	Purpose	DER Forecast	EV Forecast	EE Forecast	Non-DER/EV TOU Forecast	EV Load Shape	Fuel Price Forecast	Resource Potential
Base Electricity Demand	Reference scenario.	Base	Base	Base	Base	Managed EV charging	Base	NREL Alt-1
Land-Constrained	Understand the impact of limited availability of land for future solar, onshore wind, and biomass development.	Base	Base	Base	Base	Managed EV charging	Base	**Land-Constrained Resource Potential**
High Electricity Demand	Understand the impact of customer adoption of technologies for DER, EVs, EE, and TOU rates that lead to higher loads.	**Low**	**High**	**Low**	**Low**	**Unmanaged EV charging**	Base	NREL Alt-1
Low Electricity Demand	Understand the impact of customer adoption of technologies for DER, EVs, EE, and TOU rates that leads to lower loads.	**High**	**Low**	**High**	**High**	Managed EV charging	Base	NREL Alt-1
Faster Technology Adoption	Understand the impact of faster customer adoption of DER, EV, and EE.	**High**	**High**	**High**	**High**	Managed EV charging	Base	NREL Alt-1
Unmanaged Electric Vehicles	Understand the value of managed EV charging relative to unmanaged.	Base	Base	Base	Base	**Unmanaged EV charging**	Base	NREL Alt-1
DER Freeze	Understand the value of the distributed PV and BESS uptake in the Base forecast. Informative for program design and solution sourcing.	**DER Freeze**	Base	Base	Base	Managed EV charging	Base	NREL Alt-1
Electric Vehicle Freeze	Understand the value of the electric vehicle's uptake in the Base forecast. Informative for program design and solution sourcing.	Base	**EV Freeze**	Base	Base	Managed EV charging	Base	NREL Alt-1
High Fuel Retirement Optimization	Understand the impact of higher fuel prices on the resource plan while allowing existing firm unit to be retired by the model.	Base	Base	Base	Base	Managed EV charging	**EIA High Fuel Price**	NREL Alt-1
Energy Efficiency Resource	Understand the value of energy efficiency as a resource. Informative for program design and solution sourcing.	Base	Base	**EE Freeze + EE Supply Curves**	Base	Managed EV charging	Base	NREL Alt-1

Figure 6-8 and Figure 6-9 illustrate the total sales forecast and peak load of the various scenarios.

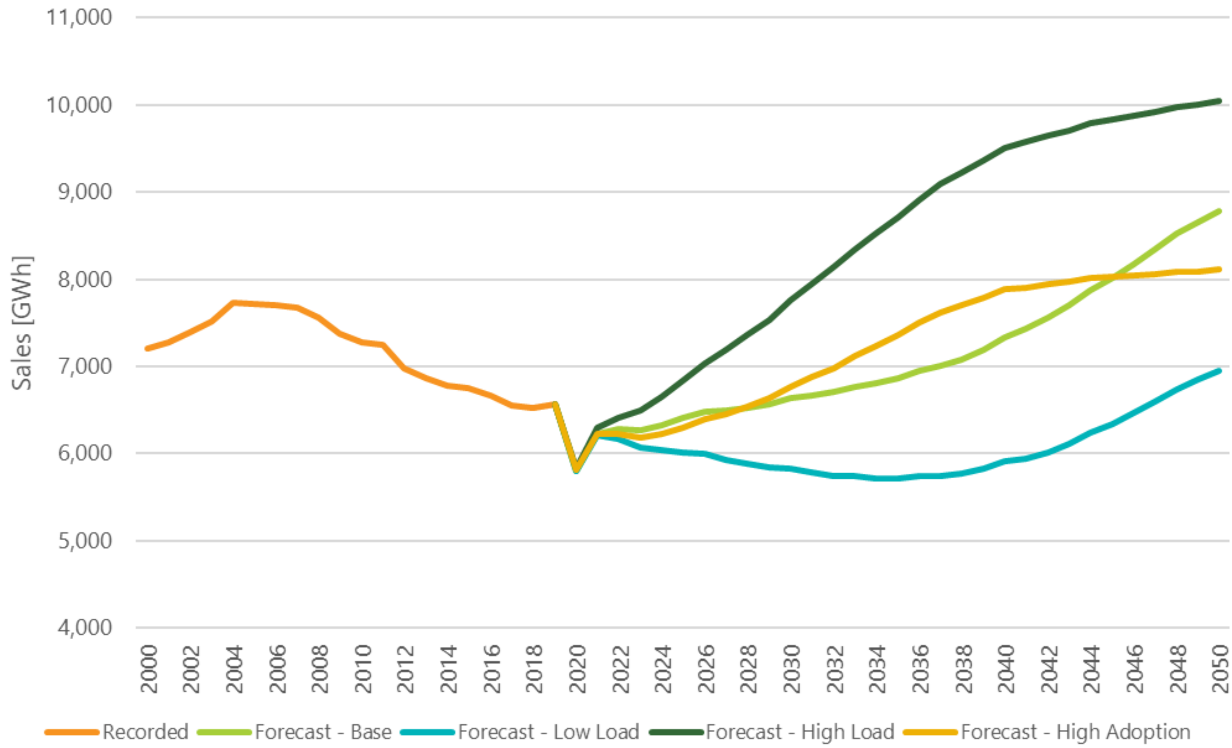


Figure 6-8. O'ahu customer-level sales forecast sensitivities

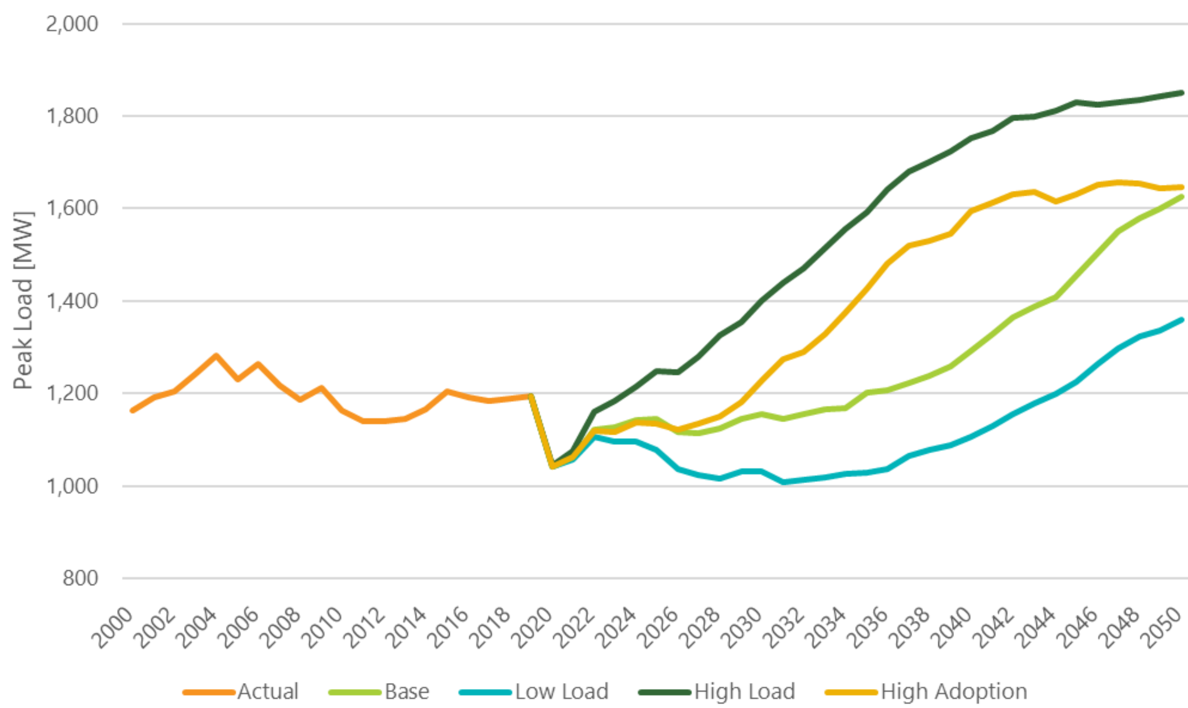


Figure 6-9. O'ahu peak load forecast sensitivities

6.9 New Resource Supply Options

New resources are made available to the model based on commercially ready technologies today, with a focus on technologies that can be acquired within the next 10 years as part of the solution sourcing process. This does not mean that future technologies are not within our long-term plans. Consistent with our renewable energy principles, we strive to make decisions today that do not crowd out future technologies. As future technologies mature those will be considered in future Integrated Grid Plans. This section describes the resource cost projections for the resources made available to the model and the renewable energy potential for solar and wind on each island.

6.9.1 Resource Cost Projections

Resource cost assumptions were based on publicly available data sets, as shown in Table 6-17.

Table 6-17. Resource Cost Data Sources

Data Source	Resources
DOE	Distributed wind [13, 14] Pumped storage hydro [15]
NREL [16]	Large-scale solar Distributed solar Onshore wind Geothermal Biomass Large-scale storage Distributed storage Combustion turbine Combined cycle Synchronous condenser Offshore wind [17]
U.S. Energy Information Administration (EIA) [18]	Waste-to-energy
Hawaiian Electric [19]	Internal-combustion engine

Resource cost assumptions began with a base technology capital cost that was adjusted for:

- Future technology trends through the planning period
- Location-specific capital and operations and maintenance cost adjustments for Hawai'i using data from the U.S. Energy Information Administration (EIA) and RSMeans
- Applicable federal and State tax incentives

Figure 6-10 summarizes the resource forecasts in nominal dollars. The resource cost forecasts from

[13] U.S. Department of Energy, 2017 Distributed Wind Market Report, https://www.energy.gov/eere/wind/downloads/2017-distributed-wind-market-report

[14] U.S. Department of Energy, 2018 Distributed Wind Market Report, https://www.energy.gov/eere/wind/downloads/2018-distributed-wind-market-report

[15] U.S. Department of Energy, 2020 Grid Energy Storage Technologies Cost and Performance Assessment, https://www.energy.gov/energy-storage-grand-challenge/downloads/2020-grid-energy-storage-technology-cost-and-performance#:~:text=Pacific%20Northwest%20National%20Laboratory%E2%80%99s%202020%20Grid%20Energy%20Storage,down%20different%20cost%20categories%20of%20energy%20storage%20systems.

[16] National Renewable Energy Laboratory 2021 Annual Technology Baseline, 2021 ATB Data, https://atb.nrel.gov/electricity/2021/data

[17] National Renewable Energy Laboratory Bureau of Ocean Energy Management, Cost Modeling for Floating Wind Energy Technology Offshore O'ahu, Hawaii, https://www.boem.gov/sites/default/files/documents/regions/pacific-ocs-region/environmental-analysis/HI%20Cost%20Study%20Fact%20Sheet.pdf

[18] U.S. Energy Information Administration, *Cost and Performance Characteristics of New Generating Technologies,* Annual Energy Outlook 2019.

[19] Internal-combustion engine costs are based on the Schofield Generating Station provided in Docket 2017-0213, in response to the Consumer Advocate's information request 19.

2020–2050 can be found in the *March 2022 Inputs and Assumptions Report*.

In the near term, there are price declines after accounting for the investment tax credit schedules for the federal and State investment tax credits. Over the longer term, after the tax credit schedules ramp down and are held constant, the resources costs generally increase over time. As noted in the NREL ATB, all technologies include electrical infrastructure and interconnection costs for internal and control connections and on-site electrical equipment (e.g., switchyard, power electronics, and transmission substation upgrades). [20] Similarly, all technologies also include site costs for access roads, buildings for operation and maintenance, fencing, land acquisition, and site preparation in the capital expenditures as well as land lease payments in the fixed costs for operations and maintenance.[21] Although the ATB does not discretely break out the percentage of the capital costs or operations and maintenance costs associated with either of these items, their inclusion is consistent with the adjustment made for recent solar, wind, geothermal, and hybrid solar projects as actual project pricing would have accounted for interconnection and land costs.

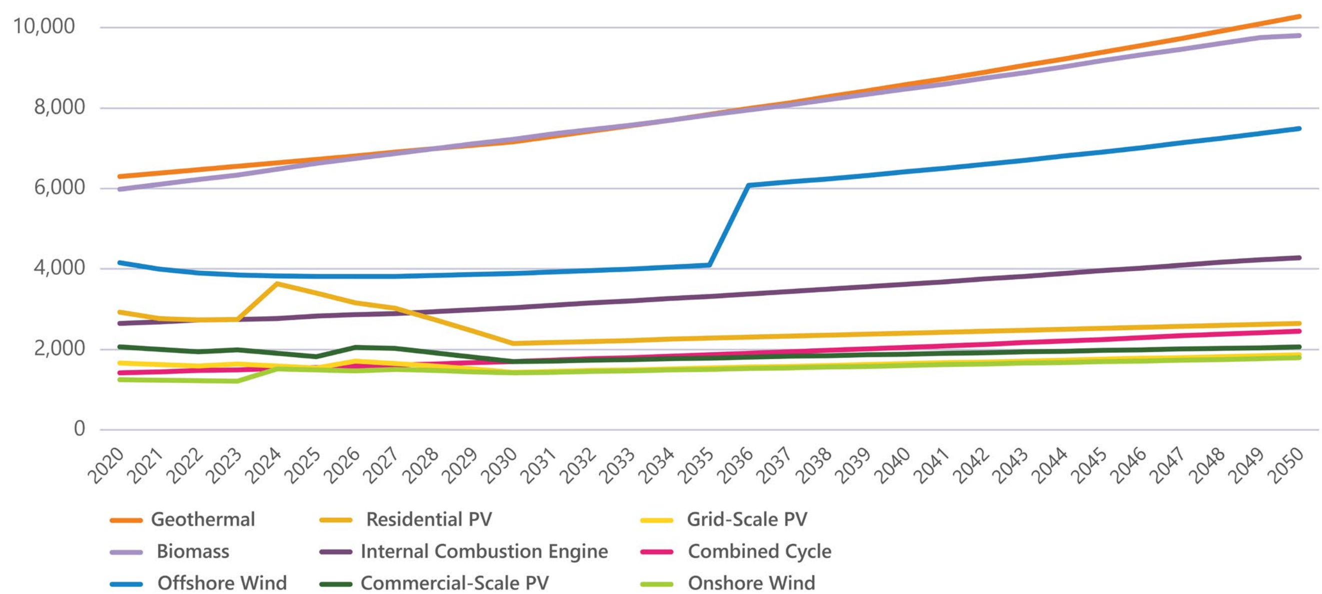


Figure 6-10. Nominal capital costs for candidate resources in $/kW

A comparison of the levelized cost of energy (cents/kWh) for solar and wind resources is shown below in Figure 6-11.

[20] See https://atb.nrel.gov/electricity/2021/definitions#capitalexpenditures

[21] Ibid.

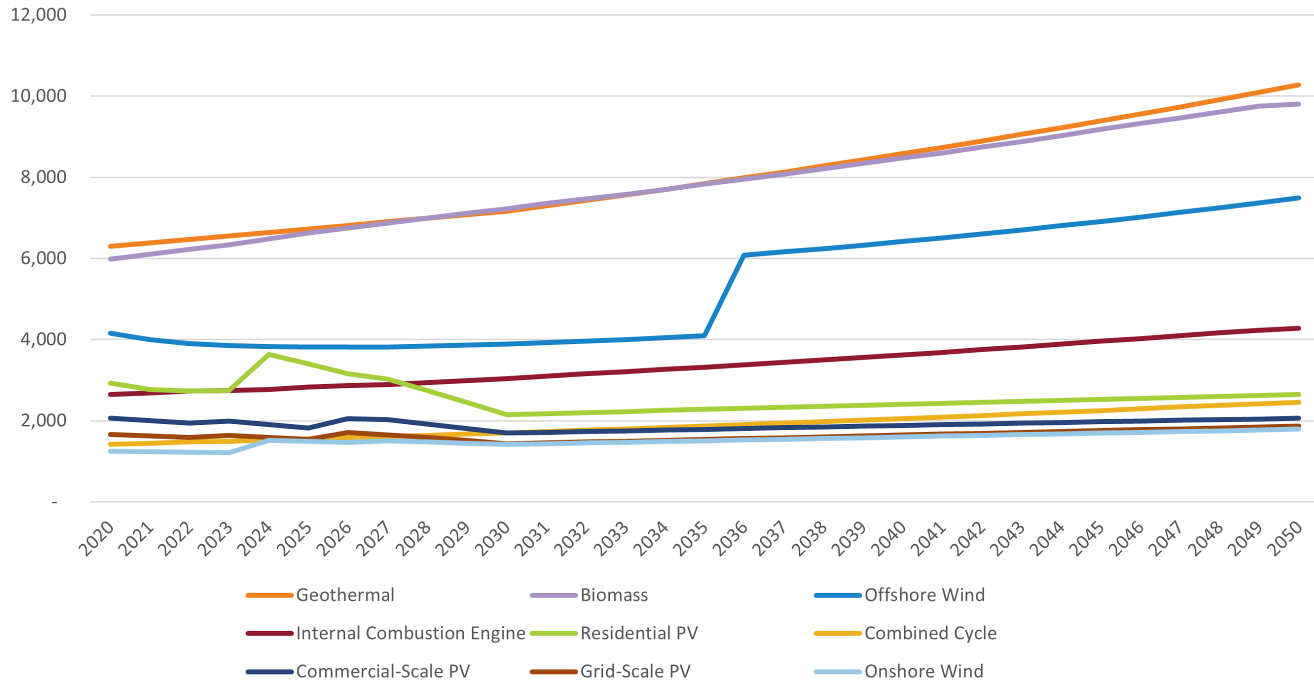


Figure 6-11. Levelized cost of energy for select Integrated Grid Plan candidate resources

6.9.2 Assessment of Wind and Photovoltaic Technical Potential

The developable potential for wind and solar was based on the resource potential study conducted by NREL. Based on stakeholder feedback, NREL revised its study to include additional scenarios described in the *July 2021 Assessment of Wind and Photovoltaic Technical Potential Report*.

6.9.2.1 Private Rooftop Solar

The potential study quantifies the technical potential of solar systems deployed on existing suitable roof areas in our service territory. Technical potential is a metric that quantifies the maximum generation available from a technology for a given area and does not consider economic or market viability. The analysis relies upon light detection and ranging (LiDAR) data. The model will consider LiDAR point clouds, buildings, solar resource from the National Solar Radiation Database, parcels, and tree canopy. The system configurations can also be considered such as fixed roof, losses, tilt, azimuth, panel type, module efficiency, inverter efficiency, and direct current (DC):alternating current (AC) ratio. The results of the analysis are provided in Table 6-18.

Table 6-18. Rooftop Solar Technical Potential Study Results

Island	Developable Plane Areas (Acres)	Capacity (MW)	Generation (GWh)	Capacity Factor (%)
O'ahu	4,934,292	3,934	6,369	21.23
Hawai'i	3,845,032	2,163	4,856	19.42
Maui	1,425,330	1,113	1,858	21.05
Lāna'i	87,724	44	112	21.20
Moloka'i	93,408	45	112	20.05

Figure 6-12 shows the locations of the O'ahu rooftop potential. The majority of the potential rooftop locations are in the urban core and populated areas. The technical potential may be needed in later years under the O'ahu Land Constrained scenario.

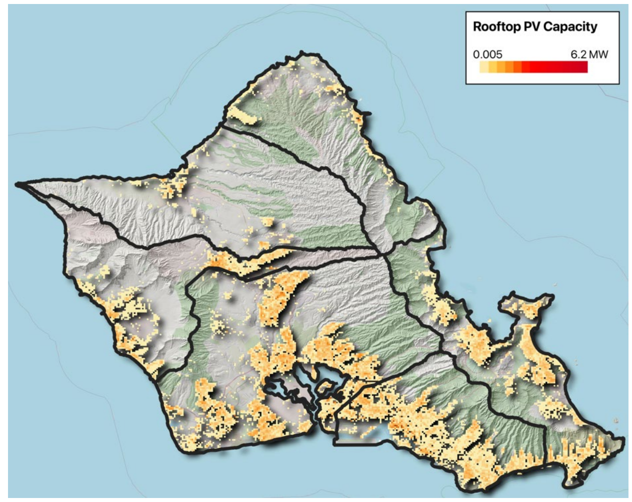


Figure 6-12. Technical potential rooftop solar capacity on O'ahu

6.9.2.2 Large-scale Wind and Solar

NREL used its Renewable Energy Potential Model (reV) to assess the potential for solar and wind energy deployment. The solar and wind resource data sets will be sourced from the National Solar Radiation Database and the Hawai'i Wind Integration National Dataset (WIND) toolkit. The solar radiation database has a temporal interval of 30 minutes and nominal spatial resolution of 4 kilometers (km). The WIND toolkit has an hourly temporal interval with a nominal spatial resolution of 2 km. The model will consider land exclusions such as slope, constructed structures, protected areas, and land cover. System configurations can also be considered in the model such as axis tracking, losses, tilt, panel type, inverter efficiency, and DC:AC ratio.

Based on stakeholder feedback the study allowed for solar development on land with up to 15% and 30% slope, among other changes to inputs. Table 6-19, below, shows the large-scale solar potential by island.

Table 6-19. Summarized Installable Capacity in MW for Large-scale 1-axis Tracking Solar Systems up to 30% Slope Land; Input Assumptions Based on Ulupono Input

Island	Large-Scale PV Potential	Land Use (Acres)
O'ahu	3,810	24,711
Moloka'i	10,411	67,708
Maui	13,687	88,960
Lāna'i	9,691	63,013
Hawai'i	76,179	495,456

The large-scale solar potential excludes the following types of land:

- Federal lands, including U.S. Department of Defense lands
- State parks and golf courses
- Wetlands
- Lava flow zones, Flood Zone A, and tsunami evacuation zones
- Urban zones
- Important agricultural land
- Soil ratings of Class A and 90% of Class B and C land
- Road and building setbacks were included

Based on stakeholder feedback the study provided for wind energy potential without limitation for windspeed. Table 6-20 shows the large-scale wind potential by island.

Table 6-20. Summarized Installable Capacity in MW for Large-scale Wind Systems up to 20% Slope Land; Input Assumptions Based on Ulupono Input

Island	Wind-Alt-1 (No Wind Speed Threshold)	Land Use (Acres)
O'ahu	256	21,004
Moloka'i	515	42,503
Maui	767	63,260
Lāna'i	509	42,009
Hawai'i	5,037	414,898

The lands excluded from the potential study are the same as solar, except that land greater than 20% slope was excluded and Class A, B, and C soil ratings were included; however, important agricultural lands were still excluded.

6.9.3 Solar and Wind Potential Assumption

The large-scale solar and wind potential assumption garnered much discussion among stakeholders, with varying perspectives on what can realistically be built because of land use and community concerns.

On the developable resource potential for onshore large-scale solar and wind, stakeholders noted that federal contracting rules would require that the U.S. Department of Defense seek the highest and best use for properties under its control, in addition to deciding whether that land would be made available for renewable energy development. Because of this circumstance, it would be difficult to make a blanket assumption that all U.S. Department of Defense lands are available to develop. Further, stakeholders raised concerns on the ease of developing projects at slopes higher than 10% because of the additional effort and cost involved. However, other stakeholders thought that solar on higher slopes could be developed, up to 30%, with some additional cost adder because some projects have already been developed on steeper slopes.

Taking into consideration the various viewpoints, we used the Alt-1 scenario for wind (no wind speed threshold) and solar potential for various scenarios from the *July 2021 Assessment of Wind and Photovoltaic Technical Potential Report* as shown in the tables above.

It is worth noting that there is substantial overlap between areas with solar resource potential and wind resource potential. And the same system infrastructure can be used to interconnect both wind and solar resources and transfer the renewable energy to the other locations of the system.

We also recognize the realities of solar and wind development in the state. To that end, the "Land-Constrained" scenario reflects the possibility of future limited land availability for solar and wind development and provide a meaningful bookend of analysis that incorporates stakeholder feedback to assume that a lower amount of land is available for project development.

6.9.4 Renewable Energy Zones

Prime locations for grid-scale development, flat land with rich solar and wind resources adjacent to existing transmission, have been developed through the Stage 1 and Stage 2 procurements. In addition to location, transmission capacity is becoming a limiting factor. The current transmission system was not designed for large generator interconnections at various locations, but rather one that supports bulk generation resources supplying power to load centers.

Creating renewable energy zones will enable efficient interconnections to the transmission system to new areas that are prime for development but either is far from existing transmission infrastructure or requires robust transmission upgrades to accommodate the interconnection of generating resources. REZ upgrades are composed of two types: (1) transmission network expansion costs, which are the transmission upgrades not associated with a particular renewable energy zone but are required to support the flow of energy within the transmission system, and (2) REZ enablement costs, 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. Further details on the renewable energy zones can be found in the Hawaiian Electric Transmission Renewable Energy Zone Study as part of the *September 2022 GNA Methodology Report*.

Section 8 discusses the REZ enablement and transmission expansion infrastructure and costs needed for each island.

7. Resilience Planning

Reliability and resilience is a top priority for our customers. As extreme events increase in frequency, we have seen the devasting impacts to grids that are unable to withstand these impacts have on society. We must act now to make our grid more resilient to better prepare the state for an extreme event. We have proposed an initial Climate Adaptation Transmission and Distribution Resilience Program that focuses on least-regrets hardening of grid infrastructure across all islands we serve. We have a long way to reach our desired target level of grid resilience. In this section we describe a strategy and roadmap to guide future resilience investments that balance affordability and resilience needs.

7.1 Resilience Strategy and Approach

Resilience is the ability of a system or its components to adapt to changing conditions and withstand and rapidly recover from disruptions. For critical infrastructure including electric power grids, resilience is generally considered to be the ability to anticipate, absorb, adapt to, and rapidly recover from a potentially catastrophic event while sustaining mission-critical functions.

Hawaiian Electric is a critical infrastructure provider. Five of the state's six island power grids are operated by Hawaiian Electric, which serves 95% of Hawai'i's 1.4 million residents. Among those, we serve the headquarters of the U.S. Indo-Pacific Command and the 36,000 active-duty military members in Hawai'i. Hawaiian Electric is the sole electric power provider to the highest geographic concentration of critical defense facilities in the nation. Widespread loss of electricity for extended periods could have significant impacts including disruption to community-lifeline and mission-critical services, loss of life, public health emergencies, environmental damage, and severe economic and social disruption. These impacts grow with increasing electrification of transportation, hybrid/remote work, and digitization of the economy.

Hawai'i and Hawaiian Electric face a unique and diverse set of resilience threats, vulnerabilities, and challenges. Hurricanes, tsunamis, wildfires, lava flows, and earthquakes pose significant threats to our system. And the frequency and intensity of hurricanes are expected to increase because of climate change. The effects of these threats are amplified by the significant geographic remoteness and isolation of Hawai'i. The Hawaiian Islands are the most isolated populated landmass in the world—5 hours from the West Coast by plane, 5 days by ship. As such, there are limited evacuation options, and mutual aid from mainland utilities and material resupply poses significant logistical complexity and long lead times. Additionally, there are no electrical interconnections between Hawaiian Electric's five island grids or to the larger mainland grid, so the generation and delivery of electricity is limited to facilities on each island. Most of Hawaiian Electric's nearly 10,000 miles of transmission and distribution lines are overhead, and a significant portion of these overhead lines were built when needed several decades ago to standards in effect at the time that were generally less robust than current standards to withstand extreme wind events, such as hurricanes. Hawai'i's volcanic islands have some of the most extreme topography found in the nation, with power lines traversing steep, rugged terrain with limited access for repairs or replacement of damaged facilities.

The primary goal of Hawaiian Electric's overall resilience strategy is to reduce the likelihood and severity of severe event impacts. Achieving a target level of resilience will depend on multiple integrated aspects of resilience including emergency response, generation/power supply resilience, transmission and distribution resilience, system/grid operation resilience, cybersecurity, physical security, and business continuity. Each plays a crucial role in safeguarding the supply and delivery of electric power in the face of threats to this critical resource.

Various potential environmental, nation-state, and actor-based physical and cyber threats may create major disruptions on an electric grid. These events result in disruptive impacts having various potential scales and scopes and inform the engineering considerations and requirements to improve the resilience of the electric grid. The scale and scope of these disruptive impacts also shape the economic impact and related value of solutions.

The "bowtie method" (Figure 7-1), as increasingly used in the industry to leverage risk-threat assessments, translates a threat-risk assessment and grid asset vulnerabilities into specific event risk prevention and mitigation analysis and solution identification. A bowtie approach helps identify where and how a portfolio of solutions will have the greatest impact for customers and communities.

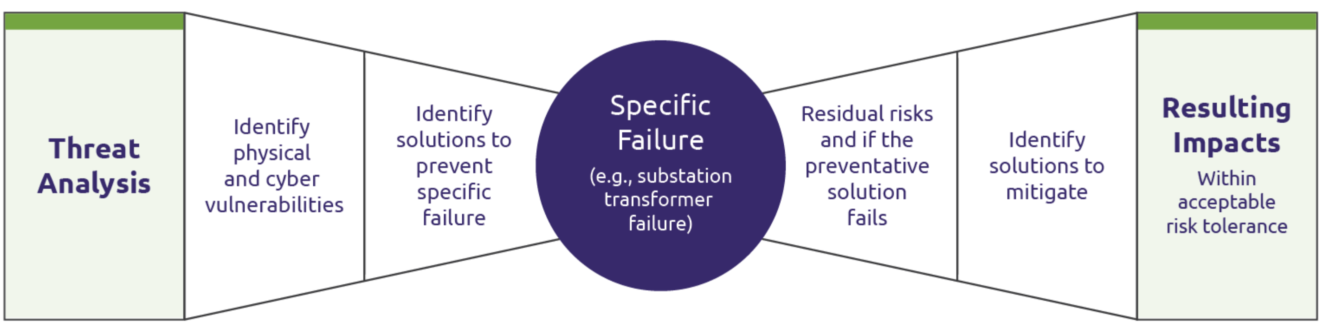


Figure 7-1. DOE resilience bowtie method

First, this method involves identifying solutions to prevent certain events from causing system failures. Preventive measures are considered foundational to ensure that critical transmission lines, substations, and distribution circuits withstand threats to ensure that critical customers and facilities have power and facilitate rapid system recovery for all customers. Preventive measures include grid hardening and can typically take from 15 to more than 20 years to complete. Preventive solutions are shown on the left side of the bowtie above.

Second, mitigation solutions can address locations where preventive solutions cannot physically or cost-effectively address the outage risks. Also, mitigation solutions may be used as near-term solutions to address risks for selected priority customers/critical facilities before the longer-term preventive measures can be implemented. Mitigation solutions are shown on the right side of the bowtie.

The specific prevention and mitigation solutions are identified through both utility asset options and potential third-party solutions (e.g., microgrids). The utility and third-party solutions are evaluated against performance metrics-driven requirements. Additionally, resilience solution prioritization involves assessing the comparative customer and community risk reduction value of the solutions related to associated generation, transmission, substation, and distribution infrastructure.

Therefore, our resilience strategy is designed to address the need to increase our system resilience to a target level of resilience. This metric-based target will be determined through stakeholder engagement supported by severe event simulation modeling and engineering-economic evaluation. The following outlines Hawaiian Electric’s general approach to system resilience enhancement:

1. **Identification and prioritization of system threats.** The Resilience Working Group identified and prioritized system threats in 2019. In alignment with Resilience Working Group priorities, Hawaiian Electric prioritized the Hurricane/Flood/Wind combined threat as the top threat to address and made this threat the primary focus of our initial resilience planning and implementation efforts.
2. **Development of performance targets and rigorous decision-making methods (Section 7.3).** This will support efforts to (1) baseline the current level of grid resilience, (2) identify the target level of resilience needed, and (3) identify and optimize a portfolio of preventive and mitigation solutions to cost-effectively address the resilience gap and reach the target level of resilience. The resulting resilience gap will be addressed by implementing preventive and mitigation solutions over time in a way that seeks to optimize cost-benefit characteristics of the portfolio while aligning with State and community priorities.
3. **System Hardening (Section 7.4).** System hardening includes investments to reduce outages and time to restore grid power via damage prevention/reduction. This includes the initial Climate Adaptation Transmission and Distribution Resilience Program, which will begin to address the most urgent and critical system needs and those that provide the broadest scope of customer and societal benefit. Future phases of foundational system hardening will incorporate performance metrics and quantitative decision-making methods described above to enable metrics-driven and cost-effective grid hardening beyond the initial phase of “no-regrets” investments.
4. **Residual Risk Mitigation (Section 7.5).** This includes investments to address near-term and longer-term residual risks and needs of individual customers and communities, filling gaps that hardening investments cannot fully mitigate cost-effectively. This can include needs that are either planning process-driven or community-driven.

Figure 7-2 below illustrates how this approach will address the resilience gap by implementing preventive and mitigation solutions over time.

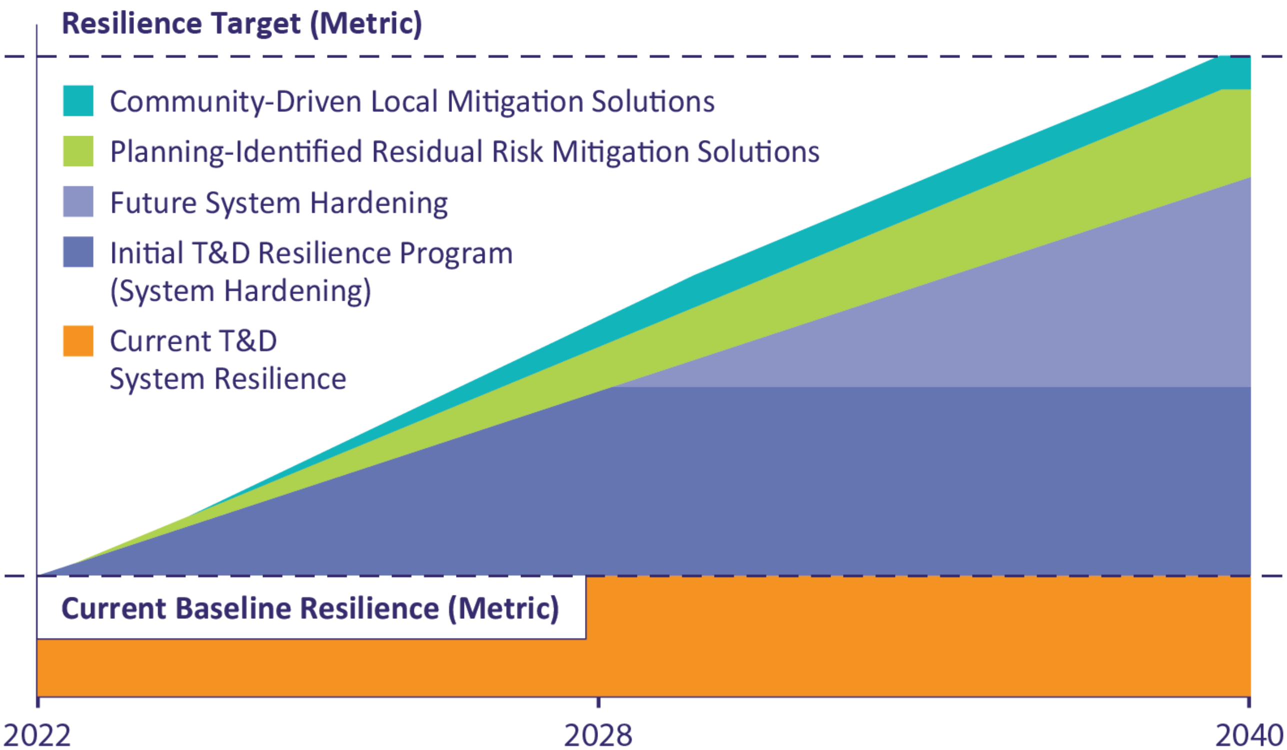


Figure 7-2. Preventive and mitigation solutions to address resilience gap

As shown in Figure 7-2, the system's current level of resilience is represented in magenta (Current T&D System Resilience). Hawaiian Electric's Initial T&D Resilience Program, shown in dark blue, represents the first phase of foundational hardening investments to increase the resilience of the system. Subsequent phases of system hardening are represented in light blue. In parallel to hardening the system, Planning-Identified Residual Risk Mitigation Solutions and Community-Driven Local Mitigation Solutions, represented in green and yellow, respectively, will further increase system resilience by mitigating residual risks that are not fully avoided or prevented by system hardening. Planning-Identified Residual Risk Mitigation Solutions include solutions driven by Hawaiian Electric's planning process (e.g., North Kohala Microgrid), while Community-Driven Local Mitigation Solutions include solutions initiated by customers or communities such as customer and hybrid microgrids. Collectively, the portfolio of complementary resilience solutions will contribute to achieving the target level of resilience over time.

7.2 Identification and Prioritization of System Threats

In 2019, the Resilience Working Group collaborated to identify and prioritize resilience threats to the electric grid. The following were the working group's priority threat scenarios for the Integrated Grid Planning process:

1. Hurricane/Flood/Wind
2. Tsunami/Earthquake
3. Wildfire
4. Physical/Cyber Attack
5. Volcano (Hawai'i Island only)

For each threat, the working group considered moderate and severe reference scenarios to provide a range of potential impacts to consider when assessing proposed solution options. Our initial resilience plans focus largely on the working group's consensus top-priority threat: Hurricane/Flood/Wind, with a secondary focus on preventing and mitigating utility-caused wildfires. As discussed in Section 7.3, specific performance targets with respect to prioritized threats should be developed and informed by stakeholders as well as the results of simulated threat models to ensure that targets are appropriate, achievable, and reasonable.

7.3 Development of Performance Targets and Rigorous Decision-Making Methods

The development of performance targets to define the target level of resilience for the grid and associated decision-making framework are key components in resilience planning.

7.3.1 Establish Target Level of Resilience

After developing and prioritizing system threats, there is a need to quantify and establish the target level of resilience for the system to achieve with respect to these threats. The process for identifying resilience metrics and establishing resilience metric target levels should ensure the following:

1. **Metrics are aligned with stakeholder values and priorities.** The metrics quantifying the "target level of resilience" need to adequately reflect what a "resilient" system looks like to relevant stakeholders.
2. **Targets are reasonably practicable.** The target level of resilience should be physically achievable for a cost that customers are willing to pay.

Establishing the target level of resilience should begin with identifying the categories of metrics that best reflect stakeholder values as the most important metrics to optimize. To begin this process, Hawaiian Electric proposes to implement the Performance Mechanism Development Process outlined in a recent report titled *Performance Metrics to Evaluate Utility Resilience Investments* (Report), which was funded by DOE and conducted as part of the Grid Modernization Laboratory Consortium (GMLC) under the project named Designing Resilience Communities: A Consequence-Based Approach for Grid Investment (DRC).[22] The Report provides a roadmap for the development of performance mechanisms for resilience, a list of principles for developing metrics,

[22] https://www.synapse-energy.com/sites/default/files/Performance_Metrics_to_Evaluate_Utility_Resilience_Investments_SAND2021-5919_19-007.pdf

a menu of suggested metrics for grid resilience as a starting point, and an Excel-based tool for visualizing the proposed metrics in the form of reporting templates. A series of technical sessions should be held (to include Hawaiian Electric, the Public Utilities Commission, Consumer Advocate, and other relevant stakeholders) to review the performance mechanism development process laid out by this Report, review the suggested metrics and identify metrics of interest, populate metrics of interest with available data to the extent feasible, and identify data gaps and how to address these gaps in the short and long terms. The Report notes that while some of the metrics can be produced in the nearer term, it also suggests "more challenging ones for utilities and communities to work towards over the years to come." Hawaiian Electric expects to use well-defined and industry-established reliability metrics (such as the System Average Interruption Duration Index [SAIDI] and System Average Interruption Frequency Index [SAIFI]) as a starting point to supplement vulnerability assessments, resilience solution development, and circuit or critical customer prioritization.

In an ideal world, it would be possible to design a system such that no customers lose power in severe events. However, such a goal is unlikely to be achievable for a cost that customers are willing to pay. It is therefore important to ensure that the target level of resilience is physically achievable for a reasonable cost. This will require (1) quantifying the system's baseline level of resilience with respect to severe event scenarios, and (2) estimating the level of investment needed to achieve the target level of resilience. Because resilience planning inherently deals with unpredictable, low-frequency, high-impact events, quantifying the expected performance of a system under severe event scenarios is possible only through using advanced modeling to derive simulated performance metric output values. Therefore, the resilience performance targets that are established will need to be refined over time based on knowledge gleaned from system performance models, described below.

7.3.2 Develop Decision-Making Methods

As described above, system performance modeling will be required to quantify the baseline level of system resilience and model investment options to achieve the desired target level of resilience.

The system performance model would be used to simulate the impacts of severe events on Hawaiian Electric's systems using a data-driven, bottom-up process. First, system performance vis-à-vis established performance metrics would be used to quantify the baseline level of resilience. Then, subsequent simulations could be run to test various resilience solutions such as hardening, automatic switching, mini-grids, and microgrids, and compare solutions and combinations of solutions against one another in terms of their expected benefits (defined by established performance metrics) versus costs.

This process of testing various resilience solutions and solution portfolios can also provide insight into the achievability and cost reasonableness of performance targets to inform future refinement.

Hawaiian Electric has contracted with the Pacific Northwest National Laboratory (PNNL) to develop and implement a performance system model for Hawaiian Electric's grids. This work will leverage and extend the tools that PNNL developed while working with Puerto Rico.

Hawaiian Electric is also tracking the development of tools and methods to quantify resilience value, such as Lawrence Berkeley National Laboratory (LBNL) and Edison Electric Institute's Interruption Cost Estimator 2.0 Tool (ICE 2.0), LBNL's Power Outage Economics Tool (POET), and Sandia

National Laboratory's (SANDIA) Social Burden Method and associated Resilient Node Cluster Analysis Tool (ReNCAT). While these tools do not themselves model system performance, they can be used to translate the failure and outage data derived from system performance models into a quantified *value* of resilience to further support investment options analysis and justification.

7.3.3 Stakeholder Engagement

Stakeholder engagement in the resilience planning process is also necessary to ensure prudent decision making. For the current hardening program and beyond, Hawaiian Electric will continue to gather stakeholder input from Resilience Working Group members and critical infrastructure partners to understand critical infrastructure priorities within and between various critical infrastructure sectors. This will include refining and maintaining critical load lists and priorities.

For future phases of system hardening and residual risk mitigation investments, stakeholder engagement will be used to understand the needs and priorities of individual communities to help target future investment analyses. The community engagement framework that began under the ETIPP effort can be leveraged, along with input and lessons learned gathered from the community meetings on O'ahu. This input can help Hawaiian Electric identify vulnerabilities and critical infrastructure considerations that are unique to each community and analyze appropriate solution options.

7.4 System Hardening

Given Hawai'i's system resilience vulnerabilities and challenges, significant investment in damage reduction is imperative for resilience improvement. We are the most isolated populated landmass in the world with limited on-island crews, materials, and equipment. This isolation poses significant difficulties to securing inventory resupply and receiving mutual aid from the mainland. In addition, Hawai'i has extreme topographic features with transmission and distribution lines running across steep, rugged terrain with limited access. There are no transmission interties between the separate island grids or to the mainland grid. If a hurricane were to strike the current unhardened grids, customers could be without power for many weeks to many months, as evidenced by the 1992 Hurricane Iniki on Kauai and the 2017 Hurricane Maria that struck Puerto Rico. In long-term outages, backup generators become reliant on fuel resupply (and are typically designed only to operate critical facilities at partial capacity). Renewable energy-based microgrids and customer distributed energy resources that are capable of islanding are typically quite limited in islanding duration capability compared to the long outage durations expected from severe events. Therefore, damage reduction measures are a central need considering the catastrophic scale and duration of outages that these types of events can cause on unhardened island grids. By reducing damage on the grid, system hardening reduces the residual outage gap to be filled by distributed resources and microgrids. Accordingly, system hardening forms the foundation of Hawaiian Electric's resilience strategy.

7.4.1 Initial Climate Adaptation Transmission and Distribution Resilience Program

Hawaiian Electric's initial Transmission and Distribution Resilience Program (Docket 2022-0135) represents the first phase of foundational system hardening investment of approximately $190 million across the islands we serve, with the potential for a 50% match of federal funding.

Because resilience performance targets and advanced decision-making methods have not yet been developed, the focus of this initial program is on "no-regrets" investments. No-regrets hardening investments are those for which there is high confidence that the investment will provide broad system and societal benefit even without the benefit of advanced methods for quantifying benefits and costs discussed in Section 7.3. Examples include hardening critical transmission lines, highway crossings, and critical poles on distribution circuits serving highly critical community lifeline infrastructure (see Figure 7-3).

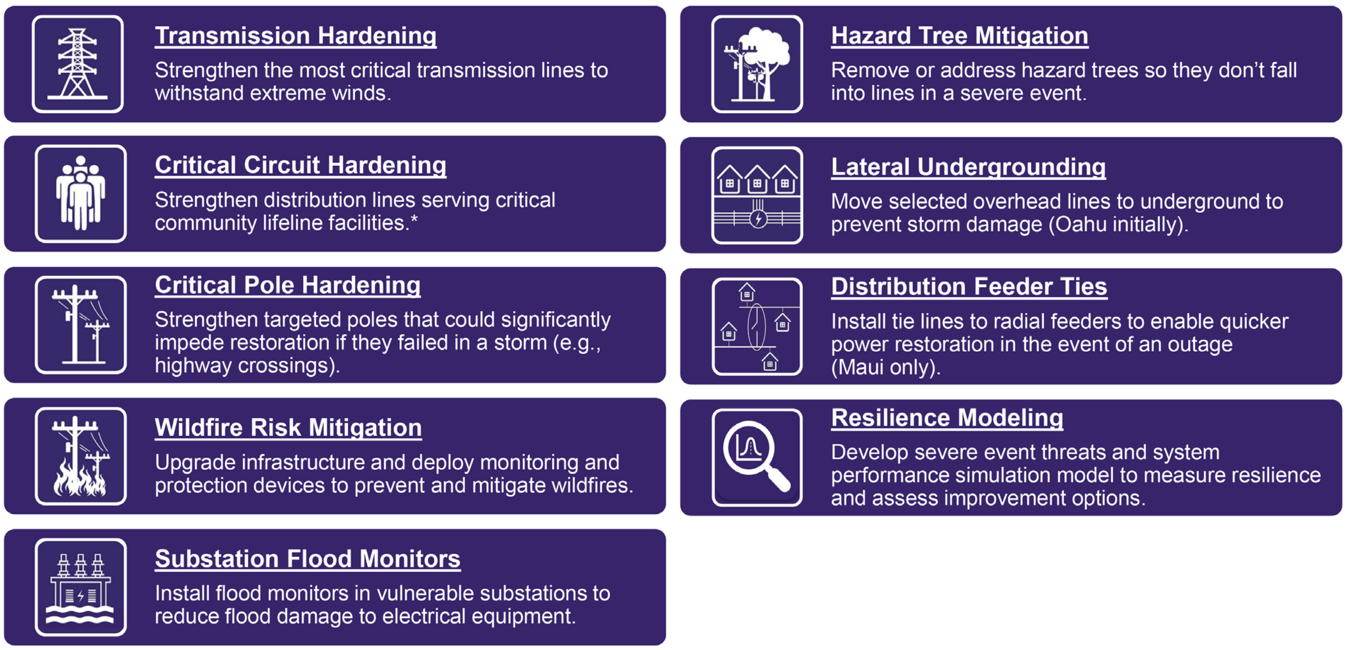


Figure 7-3. Components of initial T&D resilience program

7.4.2 Future System Hardening

Once the performance targets and quantitative decision-making capabilities discussed in Section 7.3 are developed, future phases of system hardening will be shaped by established metrics and quantitative cost-benefit-based analyses. Incorporating these advanced methods will enable Hawaiian Electric to prioritize hardening investments in a way that optimizes progress toward the target level of resilience for dollars spent in a more data-driven manner. Examples may include targeted undergrounding or community feeder hardening, including hardening work intended to pair with microgrid projects (see Section 7.5).

7.4.3 Resilience Standards Development

Improving T&D system resilience will also require evaluating and refining infrastructure equipment and apparatus standards and design policies in relation to the target performance metrics. For example, there are many open questions in power system resilience related to topics such as wind speed design policies, pole and structural material considerations with respect to wind and fire threats, and resource siting.

Hawaiian Electric is currently evaluating its wind speed design policies. Since 2007, Hawaiian Electric has designed structures to withstand wind loadings consistent with those prescribed in National Electric Safety Code (NESC) 2002. However, NESC is a minimum safety code requirement, and Hawaiian Electric is evaluating situations where wind speed design should exceed NESC 2002 requirements.

Hawaiian Electric is also evaluating the costs and benefits of various pole and structural materials. While wood and non-wood structures are designed using the same wind speed ratings, life-cycle cost, accessibility, constructibility, and environmental considerations may influence which types of materials may be ideal for different scenarios. To prevent wildfire damage, Hawaiian Electric has begun installing fire mesh and applying fire paint to poles in wildfire risk areas.

For generating facilities, each of our competitive procurements for renewable generation has an eligibility requirement for the facility's infrastructure. We require the point of interconnection to be located outside the 3.2-foot sea-level rise exposure area (SLR-XA) as described in the Hawai'i Sea Level Rise Vulnerability and Adaptation Report (2017); not located within a Tsunami 27 Evacuation Zone; and not located within the Hawai'i Department of Land and Natural Resources flood map's flood zones A, AE, AEF, AH, AO, or VE based on the Federal Emergency Management Agency's Digital Flood Insurance Rate Maps.

7.5 Residual Risk Mitigation

In addition to the preventive hardening solutions, Hawaiian Electric has initiated efforts to address "Residual Risk Mitigation." This is aimed primarily at addressing risks at the community or customer level that are not fully addressed through the System Hardening investments. While system hardening will reduce the incidence and duration of outage events through damage reduction, even hardened infrastructure can experience failures in a severe event. Therefore, mitigation investments, such as hybrid microgrids for communities or groups of critical loads, will be needed to address these residual risks by reducing the impacts of failures that do occur. Residual Risk Mitigation investments may also be used to fill resilience risk gaps while longer-term System Hardening investments are implemented. The North Kohala microgrid is an example of this type of investment, where a community microgrid is planned to be implemented prior to a longer-term effort to harden the radial sub-transmission line serving the North Kohala community. By installing the microgrid prior to hardening, the microgrid will reduce customer impacts of planned outages to make repairs or upgrades, while also mitigating impacts of unplanned outage events. Once the line is eventually hardened to resilience standards, the hardened line will provide the first line of defense through damage prevention, while the microgrid will continue to provide residual risk mitigation for planned or unplanned outages. Residual risk mitigation can also include community- and customer-driven solutions such as customer and hybrid microgrids.

7.5.1 ETIPP Microgrid Opportunity Map

In 2021, Hawaiian Electric was selected to participate in ETIPP, which provided access to technical support from the National Labs. The project in collaboration with NREL, SANDIA, and the Hawai'i Natural Energy Institute (HNEI) is currently in progress, and plans to complete a hybrid microgrid opportunity map by Quarter 2 of 2023. The objective of the map is to provide customers and Hawaiian Electric to identify areas that have overlapping criteria, such as criticality, vulnerability, and societal impact. Once completed, Hawaiian Electric will be able to leverage the map and underlying data to identify potential areas for utility or hybrid microgrid siting as well as community feeder hardening. See Section 10 for more details.

7.5.2 Resilience Value Quantification Methods

For community-level residual risk mitigation, methods such as SANDIA's Social Burden Method and associated ReNCAT may be especially useful for selecting potential microgrid sites within communities that would represent the highest avoided interruption benefit per dollar spent on microgrid development. As discussed in Section 7.3, Hawaiian Electric is tracking the development of this and other tools/methods for resilience value quantification.

7.6 Grid Modernization Dependency

In addition to foundational grid hardening discussed above, there is a need to incorporate greater grid operational awareness, control, and automated switching flexibility to enhance resilience and reliability. The next phase of our proposed grid modernization program is estimated to cost approximately $63 million[23] (including voltage management devices discussed in Section 8) and is designed to provide system operators with a holistic distribution management solution that will enable reliable and resilient operation of its island grids, while managing high and ever-increasing levels of DER penetration in its pursuit of a fully renewable generation portfolio. To do so, the solution will integrate and leverage existing operational technology (OT) and information technology (IT) systems, an expanded set of smart grid field devices, AMI, customer-sited distributed energy resources, bulk system renewables, and Hawaiian Electric's National Institute of Standards and Technology (NIST)-based Cybersecurity program. The scope of Hawaiian Electric's next grid modernization (Phase 2) 5-year scope includes:

- Advanced distribution management system (ADMS) for grid operators to effectively monitor, visualize, control, and predict conditions on the distribution grid using substation automation and distribution field devices in a coordinated fashion.
- Telecom and OT cybersecurity monitoring solution to converge security feeds from those networks into a centralized Network Operations and Security Center (NOSC) for 24×7 monitoring and response.
- Targeted proactive deployment of field devices (i.e., smart fuses, smart reclosers, motor-operated switches, and smart fault current indictors) to provide enhanced circuit switching flexibility and capability to address the needs of high-risk circuits, often located in disadvantaged communities.
  - Smart fuses and smart reclosers. We plan to install 188 smart fuses and 197 smart reclosers. They provide reclosing and isolating capabilities on distribution lines. These devices sectionalize circuits so that fewer customers experience service interruptions for faults downstream of the device, and can re-establish service automatically after a momentary fault (e.g., vegetation contacting a line), and increase system operator visibility and control.
  - Motor-operated switches. We plan to install 59 motor-operated switches on the transmission and distribution system. These devices provide remote-operated, motor-controlled switching and isolation capability, and can sectionalize circuits so

[23] Final costs to be submitted in a forthcoming application

that fewer customers experience service interruptions downstream of the device.

- Smart fault current indicators. We plan to install 1,251 of these devices to sense fault current to determine the source and location of outages. These devices will allow us to identify specific fault locations, resulting in faster restoration times.

A visual representation of the different components of the project and how they are integrated to provide the full solution is illustrated in Figure 7-4.

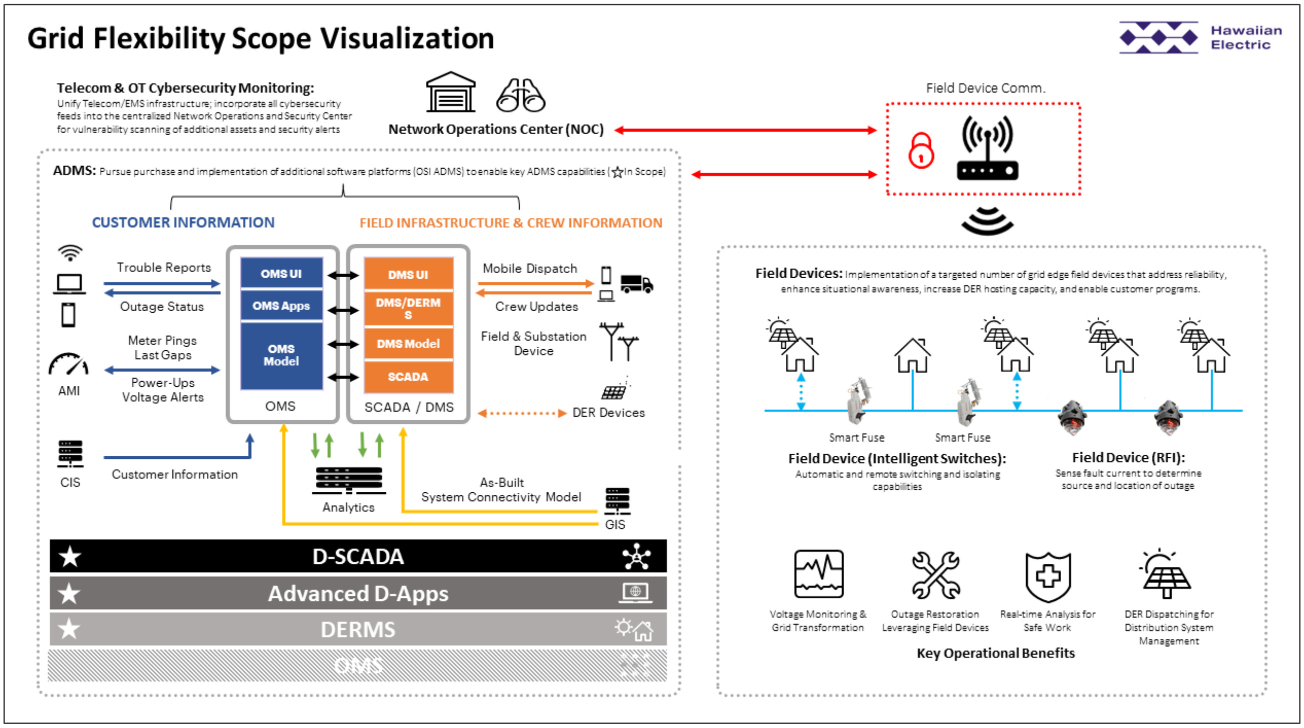


Figure 7-4. Hawaiian Electric Grid Flexibility project components

Grid hardening combined with the proposed field sensing, automated switches in a fault location, isolation and restoration scheme has proved to significantly enhance the resilience of a distribution network. These grid modernization technologies also enable the integration of customer and hybrid microgrid islanding capabilities for resilience and the utilization of their resources for "blue sky" grid services.

As illustrated in the DOE diagram below (Figure 7-5), each of these investment categories, discussed in this strategy, build upon one another to create what DOE refers to as the modern distribution pyramid. This pyramid is founded upon safe, resilient, and reliable designs and equipment standards, as well as replacement of aging and inadequate infrastructure that incorporates appropriate resilience "hardening." These physical grid investments are augmented with operational and information technologies to improve grid operational awareness, protection, controls, and automation that enable DER utilization and microgrid development.

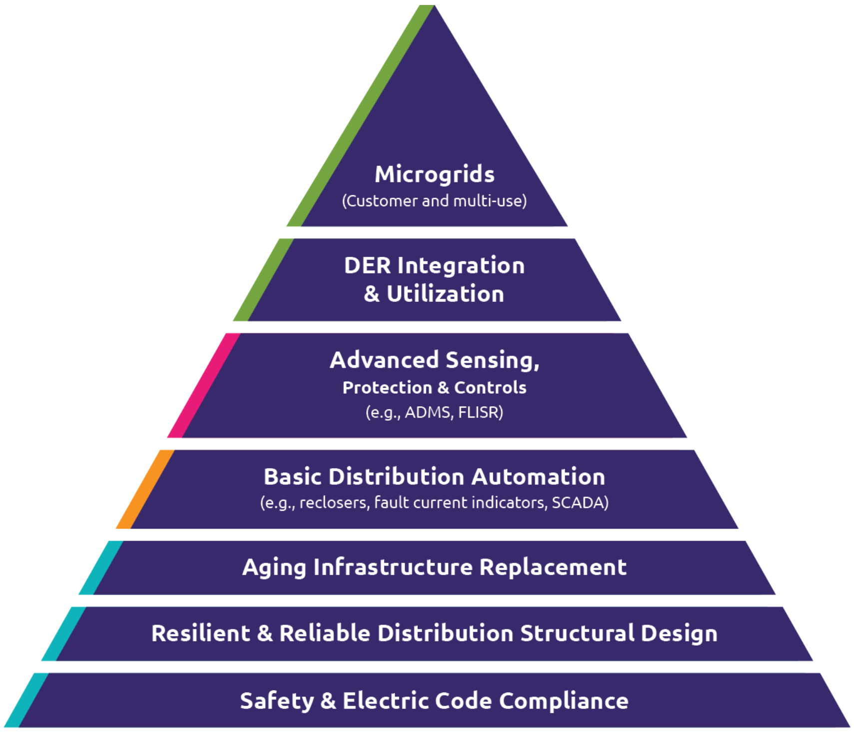


Figure 7-5. DOE distribution investment pyramid

Therefore, grid modernization investments enhance both the prevention and mitigation strategies to reduce customer outages and related impacts. Hawaiian Electric's ability to address the identified resilience and reliability needs as discussed in this strategy is dependent upon the next phase of grid modernization that seeks to significantly improve our distribution operational capabilities commensurate with industry best practices.

7.7 Resilience Working Group

Hawaiian Electric's Resilience Strategy addresses many of the recommendations of the Resilience Working Group[24] by considering threat scenarios such as Hurricane/Flood/Wind (see Section 7.2 above on identifying and prioritizing system threats); key customer and infrastructure priorities (see Section 7.4.1 above on the Initial T&D Resilience Program); elements of resilience such as reducing the probability of outages and restoration times during a severe event (see Section 7.3 above on establishing performance targets and developing decision-making methods); all possible lowest-cost solutions whether best accomplished solely through utility actions or through a combination of utility, customer, and third-party actions (see Sections 7.4 and 7.5 above on System Hardening and Residual Risk Mitigation).

Hawaiian Electric will continue to engage the Resilience Working Group and its members to understand critical infrastructure priorities and to develop and assess resilience metrics.

24 https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/resilience/20200429_rwg_report.pdf

8. Grid Needs Assessment

We define the pathways to 100% renewable energy through use of modeling tools to learn how much clean energy output is needed and from which technologies to meet the expected customer electricity demand over time. Using the scenarios and forecasts from the data collection phase we use multiple models to assess grid needs at the generation resource, transmission, and distribution levels.

In consultation with the public and stakeholders, we use leading-edge practices vetted by the Technical Advisory Panel to lay out the lowest-cost pathway that considers each island's unique needs to achieve an affordable, reliable, and 100% renewable system.

Near-term resource additions, hybrid solar and wind, provide the foundation for the lowest-cost, reliable pathway. Variable renewables (i.e., hybrid solar and wind) procured through planned procurements such as Phase 2 Tranche 2 of the CBRE program and Stage 3 will solicit projects that fulfill the remaining transmission capacity and continue to stabilize rates. In the longer term, transmission network capacity expansion (renewable energy zones) will be needed to integrate higher amounts of variable renewables.

We found that resource diversity will complement weather-dependent resources and shore up reliability. Firm renewables procured through the Stage 3 RFP can effectively diversify the resource portfolio. As existing steam plants continue to age with worsening forced outage rates on Oʻahu and lack of spare parts risks the ability to maintain generating units at Māʻalaea on Maui, reliability can be improved with the addition of the firm renewables targeted through Stage 3 that act as standby generation to be dispatched only during periods of low sun and wind. However, these resources may serve in more than just a standby role and be increasingly relied upon if adoption of electric vehicles accelerates faster than anticipated and forecasted loads increase significantly in the near term.

Additional variable renewables selected and analyzed by the planning models through 2035 will form the targets for future procurements, discussed in Section 11. Bringing these resources to commercial operation will require the development of new renewable energy zones. Transmission non-wires alternatives can cost-effectively manage the buildout of this new transmission, though this may mean that less than the full technical potential for new variable renewables can be developed. Grid modernization of the distribution system will also be needed to increase hosting capacity for distributed energy resources and accommodate new housing and electrification loads to meet statewide housing and decarbonization goals.

If renewable energy zones cannot be developed, future variable renewables after Stage 3 may be delayed until technological advancements or aggregated distributed energy resources become a more cost-effective resource option. In this scenario system stability is a concern with the current state of customer-scale inverter technology. Expanding energy efficiency may also be a cost-effective resource to pursue and solicited through a future procurement.

Ultimately the pathways we lay out serve as a roadmap to grow the customer- and community-centered energy marketplace to determine the specific technologies and projects that allow us to source the solutions we need for the grid that we want. It also identifies the transmission and distribution infrastructure needed to enable the grid as a platform to integrate technologies that we acquire from the marketplace.

8.1 Overview of Grid Needs

We identified resources to meet capacity and energy needs to serve customer demand through a multi-step process. We used a capacity expansion model to select candidate resource options based on forecasted loads, fuel prices, and resource costs to meet renewable portfolio standard and reliability planning criteria and identify a Base scenario of resource additions through the planning horizon ending in year 2050. We evaluated additional scenarios to test the sensitivity of various planning inputs on the resource selection.

- Across different load scenarios, the models consistently selected high levels of solar, wind, and energy storage because of their low cost. These resources are also used to meet load growth due to electrification of transportation and carbon reduction goals.
- In scenarios with higher electricity demand, the same mix of resources were selected in higher amounts and some amount of firm resources were also added to meet the capacity planning criteria.
- In a High Fuel Retirement Optimization scenario, the model accelerated retirements early in the planning horizon. While this may be preferred from a cost optimization perspective, practically, a staggered deactivation schedule would better ensure that replacement resources could be placed into service prior to the thermal unit's planned removal from service.
- On O'ahu, if future onshore renewables are limited in a Land-Constrained scenario, offshore wind and firm renewables will be relied upon to serve demand. Our 2030 greenhouse gas emission reduction goals may be at risk or need to be served with higher-cost renewables such as increased use of biofuels if large-scale solar and wind cannot be developed cost effectively.

We then conducted a resource adequacy analysis to examine key years in the planning horizon. Year 2030 was examined to confirm that the addition of the Stage 3 RFP variable renewable and firm resources results in a reliable system. Year 2035 was examined to identify any capacity and energy shortfalls that would need to be addressed in the next procurement, which is the next step of the Integrated Grid Planning process.

- In 2030, the O'ahu and Maui Base scenarios and the O'ahu Land-Constrained scenario that include 450 MW of hybrid solar and some new firm renewable generation from the Stage 3 RFP achieve a loss of load expectation less than 0.1 day per year. The Hawai'i Island Base scenario that includes some new variable renewable generation from the Stage 3 RFP achieves a loss of load expectation less than 0.1 day per year. Moloka'i and Lāna'i continue to maintain at least a 0.1 day/year loss of load expectation through the addition of variable renewables and storage.
- In 2035, the resources in the Base and Land-Constrained scenarios continue to provide

sufficient reliability. We tested the High electricity demand scenario to examine what additional resources after the Stage 3 RFP may be needed if actual loads are closer to the High electricity demand forecast. This information is provided below in each island's Resource Adequacy section.

After confirming that the Base and Land-Constrained scenarios would meet the reliability standard, we assessed the operations and cost of the resource plan.

- On typical days, the majority of system demand would be served by renewable resources, predominantly large-scale solar, wind, and private rooftop solar.
- By 2030, we could achieve the following renewable portfolio standard on each island: O'ahu 77%, Hawai'i Island 99%, Maui 91%, Lāna'i 95%, and Moloka'i 92% with a consolidated renewable portfolio standard of 81% and a consolidated emissions reduction relative to 2005 levels of 75%.
- In 2030, we could achieve 100% renewable energy for the following percentage of hours on each island: O'ahu 14%, Hawai'i Island 89%, Maui 57%, Lāna'i 79%, and Moloka'i 80%.
- Use of fossil-fuel firm generation is expected to decline dramatically compared to the status quo.

Additional details, supporting analyses, and resource plan data can be found in Appendix C.

8.1.1 Probabilistic Resource Adequacy

The resource adequacy step examines the reliability of the portfolios built in the RESOLVE model, which is used to optimize the resource portfolio for cost and reliability, among other factors. We then evaluated reliability of the system using metrics such as loss of load expectation (LOLE), loss of load events (LOLEv), loss of load hours (LOLH), and expected unserved energy (EUE) and compared their reliability against a known standard.

We focus primarily on loss of load expectation, which measures the average number of days per year where there is unserved energy (i.e., insufficient electricity supply to meet demand), and expected unserved energy, which is the amount of unserved energy in a given year.

We use the North American standard for loss of load expectation of 0.1 day per year, which means that the probability of unserved energy occurring in a day (regardless of duration or magnitude) is 1 day every 10 years; similarly, a loss of load expectation greater than, for example, 2 days per year, means that the probability of unserved energy occurring is at least 2 days per year. The lower the loss of load expectation is, the more reliable the system is.

We stress tested the portfolios against 5 weather years (2015–2019 solar and wind data) and 50 random thermal unit outage draws for a total of 250 samples of different conditions for available production from variable renewables and availability of firm generation thermal units.

Because the probabilistic resource adequacy is a computing resource-intensive process, select years were examined rather than the entire planning horizon. We selected 2030 and 2035 as the focus years for this analysis. By 2030, we expect that the resources procured through Stage 3 will achieve commercial operations, so studying 2030 will confirm whether the capacity and energy targeted in this procurement will satisfy near-term reliability and will assess the reliability risk if we fall short of acquiring the resources sought in our Stage 3 RFP—we explore this in detail in Section 12.

8.1.2 Grid Operations

We analyzed the Base resource plan in PLEXOS to capture the system cost over the planning horizon and provide a view of how existing and new generators are expected to operate to meet electricity demand. The O'ahu Land-Constrained plan was also analyzed in PLEXOS to determine how the dispatch may change.

We also analyzed separate Status Quo scenarios in PLEXOS and this is presented in Appendix C. At a high level, this scenario assumed the Base forecast for rooftop solar and energy storage, energy efficiency, and electric vehicles; commercial operations of Stage 1, Stage 2, and CBRE Phase 2 Tranche 1 projects; successful renegotiation of PPAs for existing independent power producers projects; and continued operation of most existing thermal units. Future resources selected by RESOLVE were not included.

8.1.3 Transmission and System Security Needs

Transmission and system security needs are identified to address transmission system capacity shortages because of future generation interconnection and load growth, and system dynamic stability needs to maintain future system stability within transmission planning criteria. In this section, we describe summary results for each island system. In Appendix D, details of the transmission analysis for each island are presented. The following summarizes our observations and recommendations from the transmission needs analysis:

- Transmission network expansion is critical for interconnecting significant quantities of large-scale renewable energy and serving future load growth. The Maui system may require transmission network expansion earlier, starting from the Stage 3 procurement, and the O'ahu and Hawai'i Island systems may require transmission network expansion in later years, depending on the location of future projects.
- Location of future generation projects matters. Projects interconnected at the proper locations may defer transmission line upgrades but also mitigate undervoltage issues that cannot be fixed solely by transmission line upgrades. This is especially true for the Hawai'i Island system.
- Grid-forming capability is critical for future system stability. To mitigate stability risks caused by momentary cessation of distributed energy resources or other grid-following resources during a system event, the study identifies minimum requirement of grid-forming resource capacity or "MW headroom" to maintain system stability performance within the planning criteria. The grid-forming resource MW headroom is the available MW capacity before a grid-forming resource generation reaches its contract (usually nameplate or rated) capacity. The MW headroom requirement is directly related to the amount of distributed generation outputting to the system at any given time.
  - It is worth noting that we have yet to obtain actual grid-forming field operation experience to validate the modeling studies. We based our recommendations on observed performance from the grid-forming resource models. Industry experience indicates promising performance of grid-forming resources at utilities such as Kauai Island Utility Cooperative and Australia Energy Market Operator. It will be important to perform model validation and performance reviews based on field operation data once the grid-forming resrouces are online.

8.1.3.1 Important Study Assumptions and Scope Limitations

For future large-scale generation interconnection, the study assumes that current interconnection sites with available grid capacity will be used first. Also, projects that withdrew from the Stage 1 or Stage 2 procurement are assumed to return in some form during the Stage 3 procurement. Once all existing capacity is occupied, future interconnection sites will be selected based on the renewable potential, community feedback, and cost of system upgrades. It is possible that actual project interconnections in future procurements are at different locations. Different interconnection locations can drive very different transmisson system capacity upgrade needs.

For each scenario, load is allocated in proportion to existing substation loads, aggregated at transmission substations. In reality, load may increase at different rates across the system.

It is worth noting that to identify transmission system capacity needs to accommodate future large-scale generation projects, distributed generation is not considered in the steady-state analyses.

Dynamic stability is sensitive to advanced grid technology development; therefore, we focus our analysis on near-term years (i.e., before 2040). New grid technology, on both the generation and customer demand sides, may result in different stability needs.

Additionally, our analysis evaluates very high penetration of inverter-based resource and DER scenarios. For example, in the Maui dynamic stability study, all studied scenarios represent 100% inverter-based resources. Currently, the industry has limited operational experience for the type of system we project to have in the near future. Both the study scope and models used for the dynamic stability study have limitations, and there may be other stability risks that are unknown at this time, and hence, not included in the current study, or represented in current models used for this study.

This analysis is focused on high-level grid needs. Detailed analyses, including fine control tuning for future large-scale generation projects, will be performed as part of the future generation projects' Interconnection Requirements Studies. Additional information on this analysis, including the High electricity demand scenarios, is provided in Appendix D.

8.1.4 Distribution Needs

Distribution grid needs are identified based on the two distribution services defined in the *Distribution Planning Methodology.*[25] To ensure adequate capacity and reliability (back-tie capabilities), the distribution grid needs are identified using two analyses:

- **Hosting capacity grid needs** assessed each circuit's ability to accommodate the forecasted DER growth for that circuit. These grid needs and a description of the hosting capacity analysis were provided in the November 2021 *Distribution DER Hosting Capacity Grid Needs* report [26].
- **Location-based distribution grid needs** assessed the ability of distribution circuits and substation transformers to serve forecasted load growth (i.e., load-driven grid

[25] *See* Hawaiian Electric Companies' Grid Needs Assessment Methodology Review Point, Exhibit 1 Distribution Planning Methodology, filed on November 5, 2021, in Docket 2018-0165.

[26] *See* Hawaiian Electric Companies' Grid Needs Assessment Methodology Review Point, Exhibit 4 Distribution DER Hosting Capacity Grid Needs, filed on November 5, 2021, in Docket 2018-0165.

needs). This analysis is further described in Appendix E.

8.1.4.1 Stakeholder Engagement and Feedback

Throughout the process of developing grid needs, we engaged stakeholders and the Technical Advisory Panel for feedback and refined the methodology as needed.

During development of the hosting capacity grid needs, we met with stakeholders in October 2021 and provided a preliminary report for stakeholder review that included details of the methodology used and preliminary grid needs results. Stakeholder feedback was incorporated into the final version that was filed in November 2021.

Similarly, during development of the load-driven grid needs, we engaged stakeholders throughout the process for feedback on the methodology and preliminary results. The methodology used to develop the location-based forecasts was shared with stakeholders in October 2021 and discussed at the Stakeholder Technical Working Group meeting. Additionally, as grid needs were identified later in the process, we met with the Technical Advisory Panel in November 2022 and the Stakeholder Technical Working Group in January 2023 to discuss the process to identify grid needs and the subsequent NWA evaluation to determine if any grid needs were qualified NWA opportunities.

8.1.4.2 Hosting Capacity Grid Needs

Of the 620 circuits[27] assessed across the five islands, most had sufficient DER hosting capacity or could accommodate the 5-year hosting capacity[28] without infrastructure investments. The remaining circuits where infrastructure investments are required to increase hosting capacity to accommodate the forecasted distributed energy resources are identified as requiring grid needs.

In the Base and Low DER forecasts, infrastructure investments or distribution upgrades (i.e., wires solutions) identified are phase balancing, installing voltage regulators, reconductoring, and installing dynamic load tap changers. The High DER forecast identified similar types of distribution upgrades as in the Base and Low DER forecasts, with the addition of step-down transformer upgrades and converting a feeder section from 4 kilovolts (kV) to 12 kV. The costs to implement these solutions are summarized by island.

8.1.4.3 Location-Based Grid Needs

In the location-based (load-driven) grid needs analysis, 645 circuits[29] and 351 substation transformers[30] were assessed with a study period through year 2030. The analysis finds that most substation transformers and circuits have sufficient capacity to accommodate the forecasted load demand. For substation transformers and circuits where there is insufficient capacity, a grid need is identified.

Most grid needs in the near term are driven by service requests,[31] or new load requests to

[27] The total circuits assessed for each island are: 384 on O‘ahu, 137 on Hawai‘i Island, 88 on Maui Island, 3 on Lāna‘i, and 8 on Moloka‘i.

[28] The study period for the hosting capacity analysis was year 2021 through year 2025.

[29] The total circuits assessed for each island are: 393 on O‘ahu, 148 on Hawai‘i Island, 93 on Maui, 3 on Lāna‘i, and 8 on Moloka‘i.

[30] The total substation transformers assessed for each island are: 204 on O‘ahu, 82 on Hawai‘i Island, 62 on Maui, 1 on Lāna‘i, and 2 on Moloka‘i.

[31] We receive service requests, or new load requests, from residential and commercial developers such as new subdivisions, condominiums, or shopping centers.

support new housing or commercial development, in specific locations on the distribution system. The grid needs driven by the corporate forecast appear to be a small subset of the total grid needs. In these scenarios, total load growth (e.g., a combination of increase in load demand plus electrification of transportation) drives the grid need and occurs mostly in the later time frame (years 2028 to 2030).

Distribution upgrades (i.e., wires solutions) identified vary by scenario. Wires solutions include, but are not limited to, new circuits, reconductoring, new substation transformers, circuit line extensions, and voltage conversions. The costs to implement these solutions are summarized by island and scenario.

8.1.4.4 Distribution Grid Needs Summary

Because the Hosting Capacity Grid Needs analysis was completed separately from the Location-Based Grid Needs analysis, grid needs resulting from both processes were compared to determine if any grid needs overlapped. In other words, it was determined whether a grid need identified for a circuit during the hosting capacity analysis also could provide a common solution to a grid need identified through the location-based process.

This reconciliation process found that the grid needs were mutually exclusive—the hosting capacity grid needs were different from the load-driven grid needs. In general, the needs are different because the load-driven grid needs occur primarily during non-solar hours when loading on circuits and transformers is typically highest, whereas the hosting capacity grid needs are mitigating overloads that occur during solar hours.

Additionally, for the load-driven grid needs, there are situations where a traditional solution is a common solution that could solve multiple grid needs simultaneously. For example, if two circuits are overloaded on the same substation transformer, this is counted as two grid needs in the location-based grid needs tables (see Table 8-7, Table 8-20, and Table 8-29)—one mitigation for each circuit. However, if a new circuit is installed, that one solution could solve both grid needs for the two existing overloaded circuits. In the Distribution Grid Needs Summary tables in the following sections, only one grid need is counted for this type of situation, reflecting the minimum number of grid needs.

8.1.4.5 Non-wires Alternative Opportunities

The NWA opportunity evaluation methodology described in Appendix F is used to determine if the grid needs identified in each island's Distribution Grid Needs Summary are qualified or non-qualified non-wires opportunities based on technical requirements and timing of need. In other words, it was determined whether an NWA procurement was likely and feasible to mitigate the grid need. This evaluation process consists of the three-step methodology shown in Figure 8-1 below.

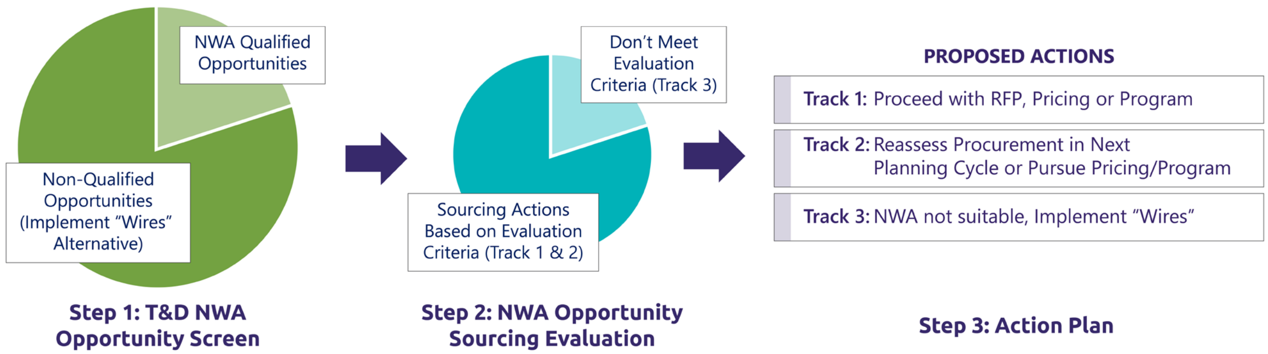


Figure 8-1. Non-wires alternative opportunity evaluation methodology

In Step 1, qualified projects are those with an in-service date beyond 2 years to allow enough lead time for non-wires procurement. For the purposes of this evaluation, projects with an in-service date of 2025 or later are deemed qualified. Non-qualified projects are those with an in-service date of 2024 or earlier.

In Step 2, additional sourcing criteria are used to evaluate the feasibility of an NWA using performance requirements, forecast certainty, project economics, and market assessment for qualified projects identified in Step 1.

A summary of the sourcing evaluation criteria is shown in Table 8-1 below.

Table 8-1. Summary of Non-Wires Alternative Sourcing Evaluation Criteria

Category	Favorable	Moderate or Uncertain	Unfavorable
Project Economics	$1M and above	Between $500k and $1M	Less than $500k
Performance	Capacity: up to 5 MW *and* Duration: up to 4 hours	Capacity: >5 MW and <10 MW *or* Duration: >4 hours and <8 hours	Capacity: 10 MW and larger *and* Duration: 8 hours or more
Forecast Certainty	Service request	Developer forecast and/or spatial allocation	
Market Assessment	0$–10%	>10%	
Operating Date (Timing)	2025–2027	2028 and later	2024 and earlier (per Step 1)

In Step 3, using the results of the weighted criteria described above, grid needs are sorted into three possible tracks:

- **Track 1**: qualified; high likelihood of NWA success for procurement
- **Track 2**: qualified; pricing/program approach (for projects less than $1 million) or reevaluate NWA opportunity in the future
- **Track 3**: non-qualified opportunities; implement wires solution

Results of the sorting by track is shown in Table 8-2 by scenario.

Table 8-2. NWA Opportunity Projects by Track

Track	Island	Scenario 1 (Base)	Scenario 2 (High Load)	Scenario 3 (Low Load)	Scenario 4 (Faster Technology Adoption)
1 (qualified: procurement likely)	O'ahu	5	3	1	6
2 (qualified: pricing approach or reevaluate later)	O'ahu	1	4	3	1
3 (non-qualified)	O'ahu	1	11	2	3
	Hawai'i Island	-	-	-	1
Total (all tracks)	n/a	7	18	6	11

8.1.5 Grid Modernization

We are also actively pursuing a grid modernization program that is foundational to realizing this Integrated Grid Plan. Phase 1, which includes the rollout of advanced meters and associated infrastructure, is currently being implemented with expected completion by the third quarter of 2024. Phase 2 will be resubmitted to the Public Utilities Commission for approval in conjunction with an application for federal funding through the Infrastructure Investment and Jobs Act (IIJA). In addition to the scope described in Section 7.6, Phase 2 includes voltage management devices to increase circuit hosting capacity on the distribution system as described in this section.

The hosting capacity needs analysis informed the scope of voltage management field devices. We identified 68 voltage regulators and 35 secondary voltage-ampere reactive (VAR) controllers to address hosting capacity at the distribution level between years 2021 and 2025.[32]

8.1.6 System Protection Roadmap

The objectives of system protection are to isolate power system faults, equipment failures, or any other unusual or extreme condition that puts the power system in jeopardy. This includes minimizing the extent and duration of the resulting forced outage and preventing system instability resulting from a system disturbance.

One technical consideration of decreasing system strength is the impact on protection systems. All electric utilities use traditional protection systems to detect and clear faults, and maintain system integrity. The Technical Advisory Panel Distribution Subcommittee was interested in how our protection systems will change in response to the higher levels of inverter-based generation. At the November 16, 2022,[33] Technical Advisory Panel Distribution Subcommittee meeting and the

[32] The updated field devices scope for Grid Modernization Phase 2 also includes projected needs between 2024-2028. The updated Phase 2 field devices scope includes 106 total voltage regulators of which 46 voltage regulators are common to both the distribution grid needs and the Phase 2 scope.

[33] See https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/technical_advisory_panel/20221110_protection_roadmap.pdf

December 1, 2022, Technical Advisory Panel meeting we presented our system protection roadmap, which summarized how the protection systems are anticipated to change and what would trigger those changes. For example, if breaker clearing times are too slow and causing instability, then faster two-cycle breakers or circuit switchers would be needed. If line current differential schemes become slow from lack of system strength, then moving to traveling-wave schemes may mitigate those issues. We are currently in the process of upgrading certain components of our protection scheme; for example, moving from electromechanical relays to more capable microprocessor relays, and upgrading fuses that may not operate timely because of lack of fault current to smart fuses (as part of the grid modernization Phase 2 scope).

The protection system will evolve over time and will be addressed as the system undergoes changes. For example, as large-scale generation is added to the system, protection in that area or region of the grid will be evaluated and addressed to maintain the protection system objectives. Common to the various protection solutions is high-speed communications, which enables protection to act quickly and decisively based on situational awareness. This Integrated Grid Plan does not directly identify future investments needed to mitigate potential protection issues; however, as we learn more about our system and how large-scale and customer-scale inverters perform, we will gain more insight into the protection investments needed for the future.

8.2 O'ahu

This section describes the results of the grid needs assessment for O'ahu through the multistep process that includes modeling capacity expansion, resource adequacy, operations of the system, transmission and system security needs, distribution needs, and iterations or adjustments made to determine the preferred plan.

8.2.1 Capacity Expansion Scenarios

In the Base scenario below (Figure 8-2), RESOLVE builds standalone BESS, hybrid solar, and onshore wind, achieving approximately 80% renewable energy by 2030. In 2035 offshore wind is added, and by 2050 biomass is added. The Low Load and Faster Technology Adoption scenarios do not build the biomass by 2050 while the High Load scenario does. Existing fossil fuel–based resources are shown as firm renewable resources in 2050 because of their switch to biofuels in 2045. All cases achieve their RPS targets with consistent increases in utilization of renewable resources. Figure 8-3 shows the annual generation and renewable portfolio standards for O'ahu for the Base, Low Load, High Load, and Faster Technology Adoption scenarios.

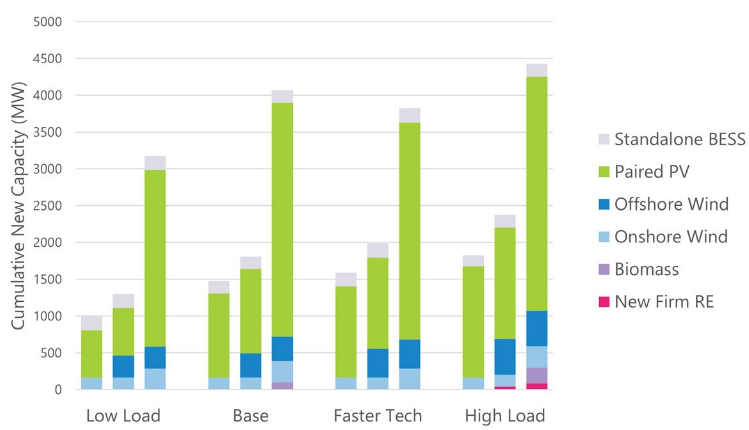


Figure 8-2. O'ahu: cumulative new capacity selected by RESOLVE in 2030, 2035, and 2050 for the Base, Low Load, High Load, and Faster Technology Adoption scenarios

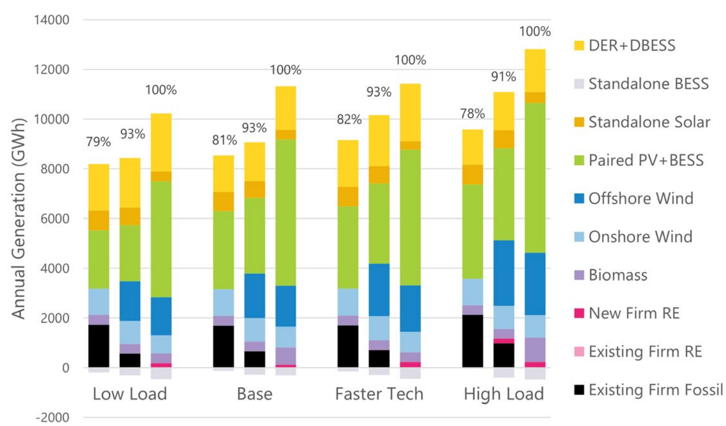


Figure 8-3. O'ahu: annual generation and RPS from resources in 2030, 2035, and 2050 for the Base, Low Load, High Load, and Faster Technology Adoption scenarios

8.2.1.1 Land-Constrained Scenarios

In discussing the capacity expansion results of the O'ahu Land-Constrained scenario with the Technical Advisory Panel, they noted that this scenario does not meet our goal of 70% carbon reduction by 2030 and that the assumptions in this scenario to constrain the available large-scale renewables may be closer to reality than other scenarios. When enforcing this constraint in RESOLVE through the RPS target, there is a limited change in resource plan buildout; however, additional generation from new and existing firm renewables (i.e., biodiesel) is used to meet the 70% carbon reduction goal by 2030 compared to the Land-Constrained scenario that is not required to meet that goal. This indicates that the DER aggregator resource (the only remaining resource option that can be built) is a higher-cost option than the incremental biodiesel generation from firm renewables in 2030 when the decarbonization goal must be met. We note that, because the DER aggregator resource is not selected until 2045 and 2050 when we must comply with the 100% renewable energy mandate, new advanced generation technologies could become available prior to 2045 that could accelerate the path to 100% renewable energy in a Land-Constrained scenario.

Figure 8-4 shows cumulative new capacity and Figure 8-5 shows annual generation and renewable portfolio standards for O'ahu for the Land-Constrained scenario with 70% RPS requirement in 2030.

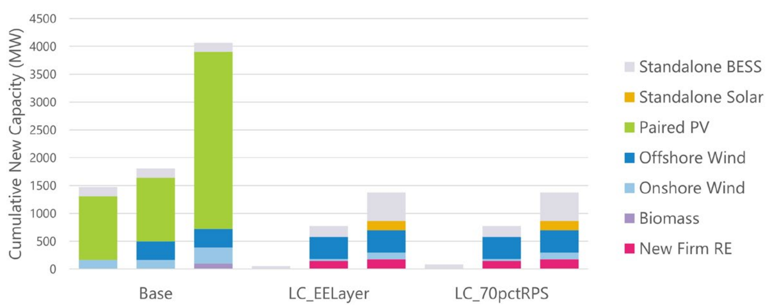


Figure 8-4. O'ahu: cumulative new capacity selected by RESOLVE in 2030, 2035, and 2050 for the Base, Land-Constrained, and Land-Constrained with 70% RPS by 2030 constraint

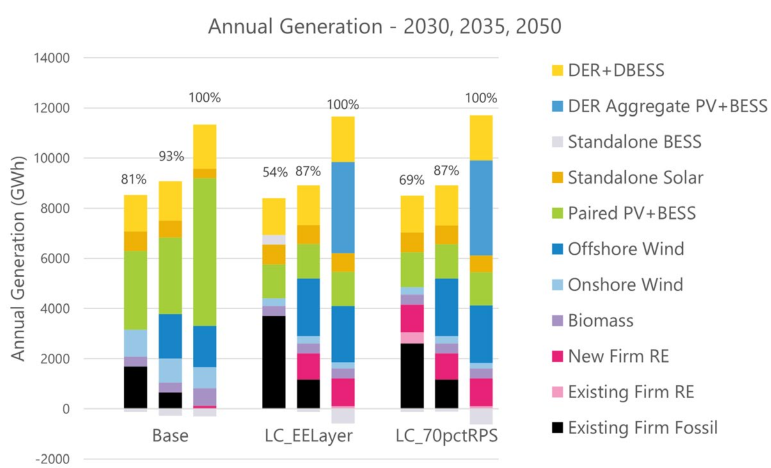


Figure 8-5. O'ahu: annual generation and RPS from resources in 2030, 2035, and 2050 for the Base, Land-Constrained, and Land-Constrained with 70% RPS by 2030 constraint

8.2.1.2 High Fuel Retirement Optimization Scenario

We evaluated a High Fuel Retirement Optimization scenario to determine the impact to our fossil-fuel retirement plans and other resources. In the High Fuel Retirement Optimization scenario, RESOLVE chooses to retire 570 MW of thermal capacity (see Figure 8-6). Because RESOLVE performs a linear optimization, the additional retirements may consist of partial unit retirements. These additional retirements occur early in the planning horizon before 2030 and are replaced with biomass and increased amounts of hybrid solar. By 2050, the High Fuel Retirement Optimization scenario builds less hybrid solar and offshore wind because of the increased amount of biomass installed in 2030.

Because RESOLVE front-loads the removal of units early in the planning horizon, extreme care must be taken to ensure that customers are not adversely affected by an inadequate system. It is anticipated that removal of existing thermal generating units would result in a loss of load expectation greater than 0.1 day per year. Additionally, this scenario significantly accelerates the buildout of hybrid solar compared to the Base scenario, which would require an extraordinary effort by the marketplace to ensure that sufficient resources are built prior to retirement of firm generation. In practice, to ensure that sufficient replacement resources are in service to facilitate the retirements selected in this sensitivity, the unit removals would need to be staggered similar to our proposed removal-from-service schedule. Otherwise, the retirements shown in this sensitivity would increase the risk of unserved energy to our customers.

Figure 8-6 shows cumulative new capacity for O‘ahu, comparing the Base and High Fuel Retirement Optimization scenarios.

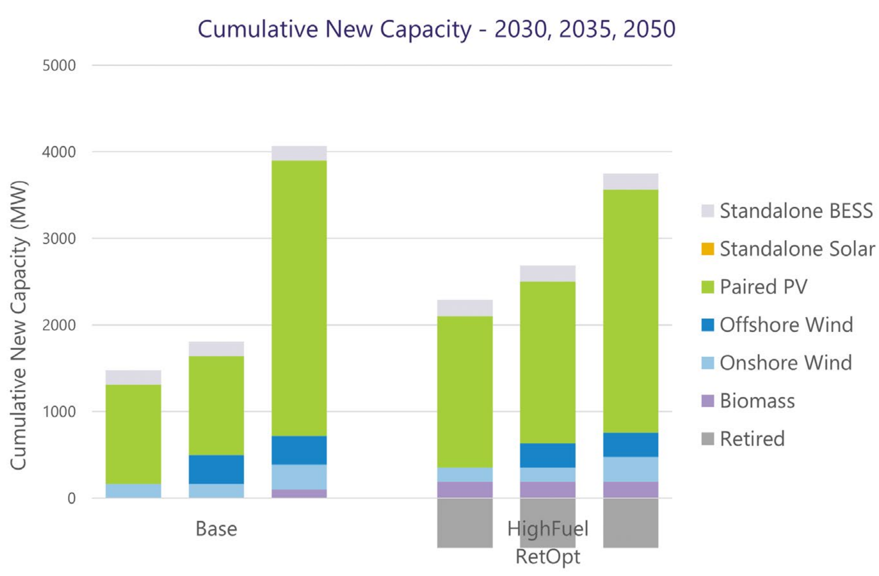


Figure 8-6. O‘ahu: cumulative new capacity selected by RESOLVE in 2030, 2035, and 2050 for the Base and High Fuel Retirement Optimization scenarios

However, the High Fuel Retirement Optimization scenario validates a key point, that we must urgently move to integrate lower-cost renewable resources (than the price of fossil fuel) as soon as practicable to lower the cost of electricity. Figure 8-7 shows annual generation and renewable portfolio standards for O'ahu for the Base and High Fuel Retirement Optimization scenarios.

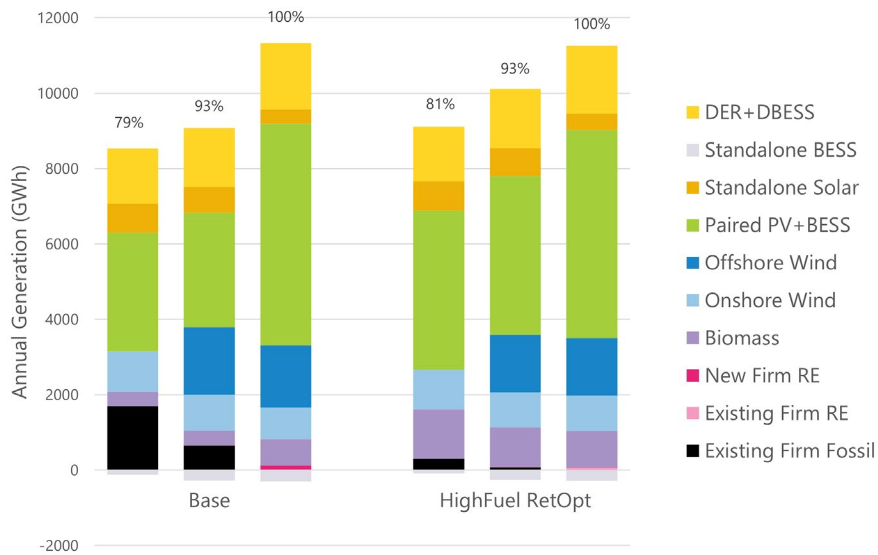


Figure 8-7. O'ahu: annual generation and RPS from resources in 2030, 2035, and 2050 for the Base and High Fuel Retirement Optimization scenarios

8.2.2 Resource Adequacy

In 2030, several key decision points are illustrated by the probabilistic resource adequacy analyses. By 2030, 371 MW of existing thermal capacity is planned to be removed from service. The impact of this planned removal is mitigated by the addition of new resources through the Stage 3 RFP. However, if we acquire less than the full Stage 3 targeted need, additional resources may be needed through additional procurements or planned removals of fossil fuel–based generation may be delayed. This is not desirable because of the present risks to the existing generation fleet as discussed in Section 12.

For planning purposes, we have assumed a stepwise approach to retirements or deactivations of our existing fossil-fuel generating fleet on O'ahu, as shown in Table 8-3. The scheduled removal from service for O'ahu is based primarily on the age of the unit.

Table 8-3. Generating Unit Deactivation/Retirement Assumptions

Year	Generating Unit
2024	Waiau 3–4 removed from service (93.5 MW)
2027	Waiau 5–6 removed from service (108.1 MW)
2029	Waiau 7–8 removed from service (169.1 MW)
2033	Kahe 1–2 removed from service (164.9 MW)
2037	Kahe 3–4 removed from service (171.5 MW)
2046	Kahe 5–6 removed from service (269.5 MW)

If development of future large-scale renewables is limited in a Land-Constrained scenario:

- We expect loss of load of less than 0.1 day per year, assuming that the planned deactivations through 2030 and the full target for the Stage 3 procurement is acquired (300 MW of new firm generation by 2029 and 450 MW of new variable renewable generation paired with storage by 2027). Acquisition of the full Stage 3 procurement targets may facilitate the deactivation of additional fossil fuel–based generators by 2030, beyond the planned removals.

- We expect a loss of load greater than 0.1 day per year (less reliable) if less than the full target for firm renewables in the Stage 3 procurement is acquired (e.g., 150 MW of new firm generation by 2029 and 450 MW of new variable renewable generation paired with storage).

If development of future large-scale renewables reaches the target presented in the Base scenario:

- We expect loss of load of less than 0.1 day per year, assuming that the planned deactivations through 2030, the full target for the Stage 3 procurement is acquired (300 MW of new firm generation by 2029 and 450 MW of new variable renewable generation paired with storage by 2027), and the marketplace delivers a combination of resources, consistent with the Base scenario, hybrid solar (1,150 MW), onshore wind (160 MW), and standalone storage (170 MW). Procurement of the full Stage 3 targets and additional variable renewable and storage resources may also facilitate the removal of further existing thermal units.
- We expect loss of load of less than 0.1 day per year if less than the full target for the firm renewables in the Stage 3 procurement is acquired (150 MW of new firm generation by 2029 and 450 MW of new variable renewable generation paired with storage by 2027) and the same combination of Base scenario resources. These resources may also facilitate the removal of additional fossil fuel–based generators by 2030, beyond the planned removals.

By 2035, we assumed deactivation of an additional 165 MW of existing fossil-fuel capacity after deactivating 371 MW by 2030. The reliability impact of this planned deactivation is mitigated by the addition of new resources through the Stage 3 procurement. However, if less than the full Stage 3 target is acquired, additional resources may be needed through the solution sourcing process.

If development of future large-scale renewables is limited in a Land-Constrained scenario:

- We expect loss of load of less than 0.1 day per year, assuming that the planned deactivations through 2035, the full target for the Stage 3 procurement is acquired (300 MW of new firm generation by 2029, an additional 200 MW of new firm generation by 2033, and 450 MW of new variable renewable generation paired with storage by 2027), and the marketplace delivers 400 MW of offshore wind. Procurement of the full Stage 3 targets and offshore wind may also facilitate the deactivation of additional fossil fuel–based generators by 2035.
- We expect loss of load of greater than 0.1 day per year if less than the full target for the firm renewables in the Stage 3 procurement is acquired (150 MW of new firm generation by 2029 and 450 MW of new variable renewable generation paired with storage by 2027) and Kalaeloa Partners' combined cycle plant expires at the end of its amended 10-year contract term. Reliability can be improved to a loss of load expectation of less than 0.1 day per year by reactivating units previously deactivated at Kahe and Waiau.

If development of future large-scale renewables achieves their technical potential in the Base scenario:

- We expect loss of load of less than 0.1 day per year, assuming the planned deactivations through 2035, the full target for the Stage 3 RFP is procured (300 MW of new firm generation by 2029, an additional 200 MW of new firm generation by 2033, and 450 MW of new variable renewable generation paired with storage by 2027), and the marketplace delivers a combination of resources, consistent with the Base scenario, hybrid solar (1,150 MW), onshore wind (160 MW), offshore wind (400 MW), and standalone storage (170 MW). Procurement of the full Stage 3 procurement targets and offshore wind may also facilitate the deactivation of additional steam units by 2035.

- We expect loss of load to be less than 0.1 day per year if we acquire less than the full target for the firm renewables in the Stage 3 procurement (150 MW of new firm generation by 2029 and 450 MW of new variable renewable generation paired with storage by 2027), Kalaeloa Partners' combined cycle plant expires at the end of its amended 10-year contract term, and we acquire the same combination of Base scenario resources.

Probabilistic Resource Adequacy Summary

Table 8-4 shows the 2030 Resource Adequacy results for the Base and Land-Constrained resource plans that were produced by RESOLVE. The results show that, in 2030, both resource plans developed by RESOLVE should meet our reliability targets.

Table 8-4. Probabilistic Analysis: Results Summary, Oʻahu, 2030—Summary of Base and Land-Constrained 2030 Resource Adequacy Results

Scenario	Existing Firm (MW)	New Firm (MW)	Stage 3 RFP (MW)	Future Wind (MW)	Future Hybrid Solar (MW)	Future Standalone BESS (MW)	LOLE (Days/ Year)	LOLEv (Event/ Year)	LOLH (Hours/ Year)	EUE (MWh/ Year)	EUE (%)
RESOLVE Base	1,173	300	450	164	1,145	167	0.00	0.00	0.00	0.00	0.000
RESOLVE Land-Constrained	1,173	300	450	0	0	54	0.00	0.00	0.01	0.00	0.000

Table 8-5 shows the 2035 resource adequacy results for the Base and Land-Constrained resource plans that were produced by RESOLVE. In the Land-Constrained resource plan, RESOLVE selected a 153 MW combined cycle to be installed in 2035. In the 2035 probabilistic resource adequacy analysis, however, the 153 MW combined cycle was assumed not to be installed to test whether this firm generator is needed for resource adequacy.

Table 8-5. Probabilistic Analysis: Results Summary, Oʻahu, 2035—Summary of Base and Land-Constrained 2035 Resource Adequacy Results

Scenario	Existing Firm (MW)	New Firm (MW)	Stage 3 RFP (MW)	Future Wind (MW)	Future Hybrid Solar (MW)	Future Standalone BESS (MW)	LOLE (Days/ Year)	LOLEv (Event/ Year)	LOLH (Hours/ Year)	EUE (MWh/ Year)	EUE (%)
RESOLVE Base	800	508	450	564	1,145	167	0.00	0.00	0.00	0.00	0.000
RESOLVE Land-Constrained	800	508	450	430	0	194	0.00	0.01	0.01	0.00	0.000
RESOLVE Base, High Load	800	508	450	564	1,145	167	0.00	0.00	0.00	0.00	0.000
RESOLVE Land-Constrained, High Load	800	508	450	430	0	194	0.65	1.42	3.28	0.60	0.007

The results show that, in 2035, both the Base and Land-Constrained plans developed by RESOLVE should meet our reliability targets. However, further analysis is needed for offshore wind addition as it does not have a robust historical record of production in Hawai'i (unlike onshore wind and solar), which could materially impact its reliability contributions.

In 2035, assuming a High electricity demand scenario and all 450 MW of hybrid solar from the Stage 3 RFP:

- Approximately 1,225 MW of new hybrid solar is needed, in addition to the 450 MW of hybrid solar from Stage 3, to bring the system loss of load expectation below 0.1 day per year.
- Approximately 200 MW of new firm generation is needed, in addition to the 500 MW of firm generation from Stage 3, to bring the system loss of load expectation below 0.1 day per year.

See Section 12 for more details on risks of the resource portfolio given uncertainties in procuring and acquiring the optimal mix of resources.

8.2.3 Grid Operations

The transition to 100% renewables will necessitate a change in how the firm thermal generators on our system operate. Scenarios with more renewable resources will use thermal generators less often. This is shown in the daily energy profiles and operational statistics in this section.

8.2.3.1 Status Quo Typical Operations

As stated above, a Status Quo scenario was run through PLEXOS. In this scenario, it assumed the Base forecast, commercial operations of Stage 1, Stage 2, and CBRE Phase 2 Tranche 1 projects; successful renegotiation of existing independent power producers; and continued operation of most existing thermal units. The Status Quo plan excluded CBRE Phase 2 Tranche 2, Stage 3 RFP resources, and future resources selected by RESOLVE. Shown below in Figure 8-8 and Figure 8-9 are the dispatch of the resources in a Status Quo resource plan in 2030 and 2035, respectively, for a few days with average load.

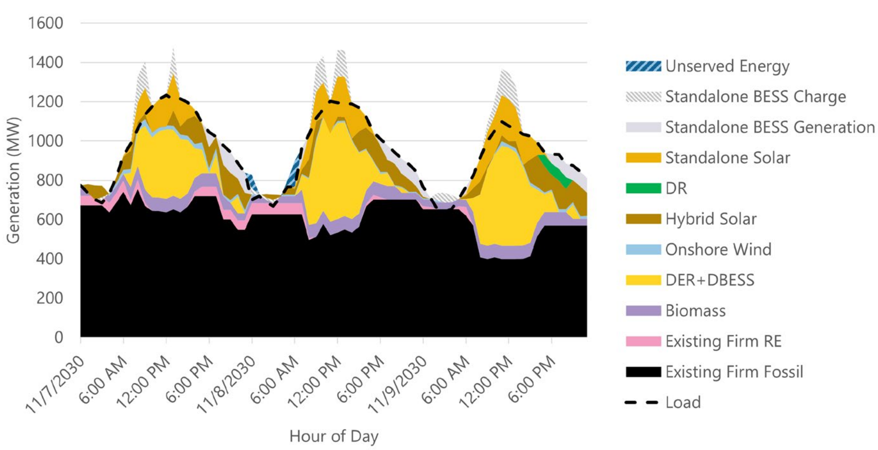


Figure 8-8. Oʻahu: detailed Status Quo energy profile, 2030 median load day (November 7–9, 2030)

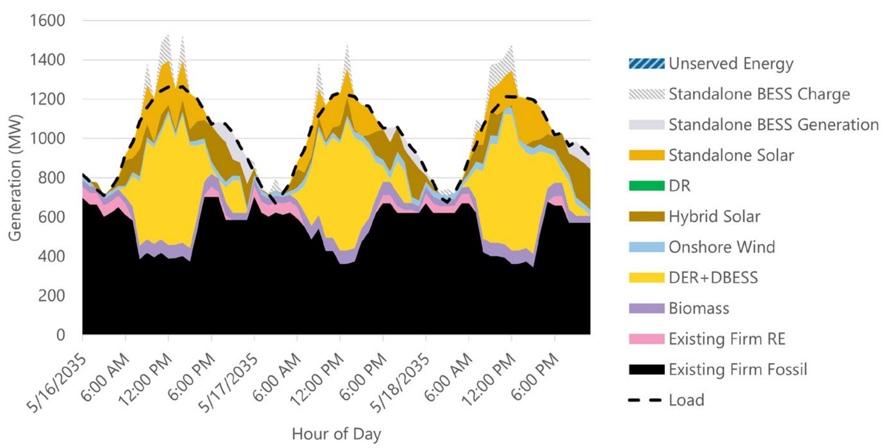


Figure 8-9. Oʻahu: detailed Status Quo energy profile, 2035 median load day (May 16–18, 2035)

8.2.3.2 Base Scenario Typical Operations

The dispatch of the resources in the Base resource plan in 2030 and 2035, respectively, for a few days with average load are shown below in Figure 8-10 and Figure 8-11. In the Base resource plan, during midday, most of the load is expected to be met from variable renewable resources. The firm fossil fuel–based generators are used primarily during morning and evening hours.

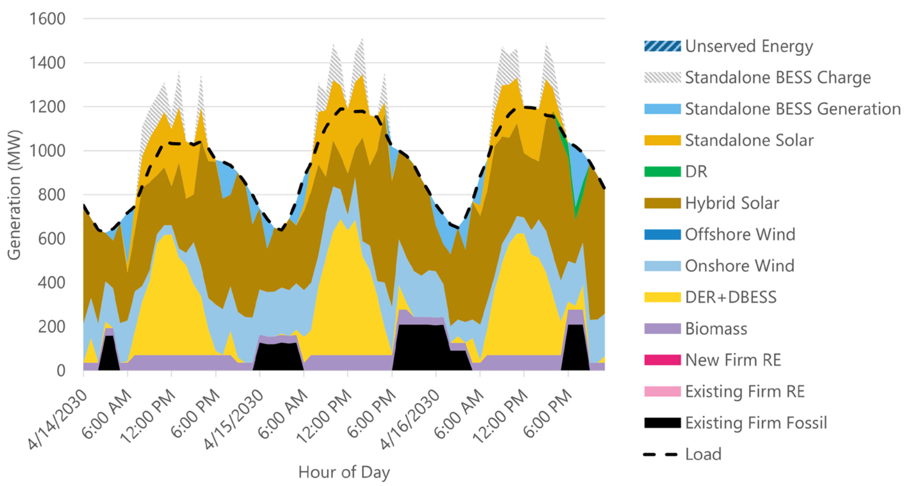


Figure 8-10. Oʻahu: detailed Base energy profile, 2030 median load day (April 14–16, 2030)

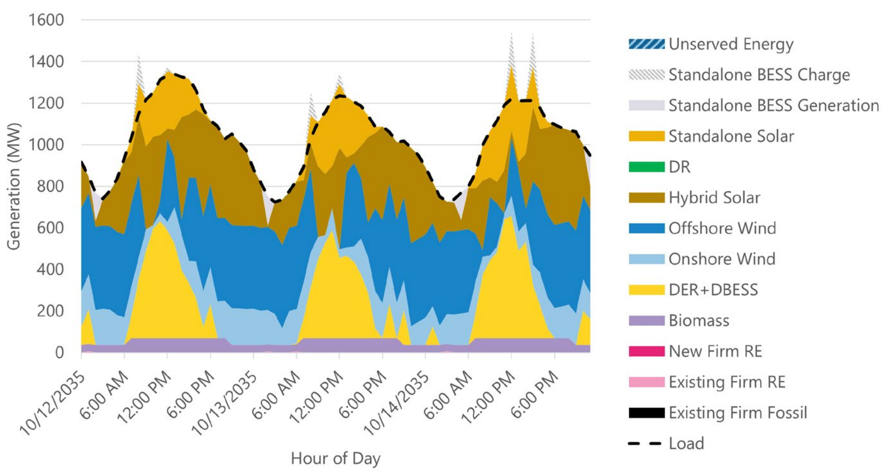


Figure 8-11. O'ahu: detailed Base energy profile, 2035 median load day (October 12–14, 2035)

8.2.3.3 Land-Constrained Scenario Typical Operations

The dispatch of the resources in the Land-Constrained resource plan in 2030 and 2035, respectively, for a few days with average load are shown below in Figure 8-12 and Figure 8-13. In the Land-Constrained scenario, we expect greater fossil fuel–based generation during midday than the Base scenario because of the lower amount of future renewables being added.

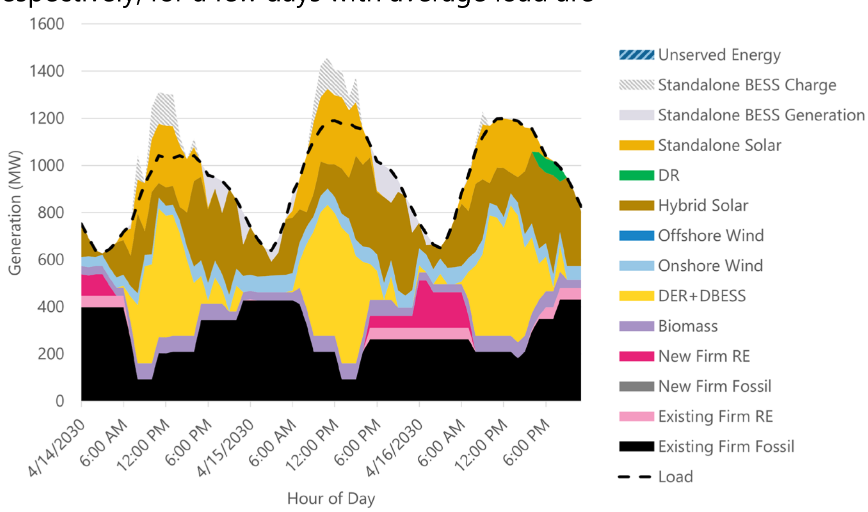


Figure 8-12. O'ahu: detailed Land-Constrained energy profile, 2030 median load day (April 14–16, 2030)

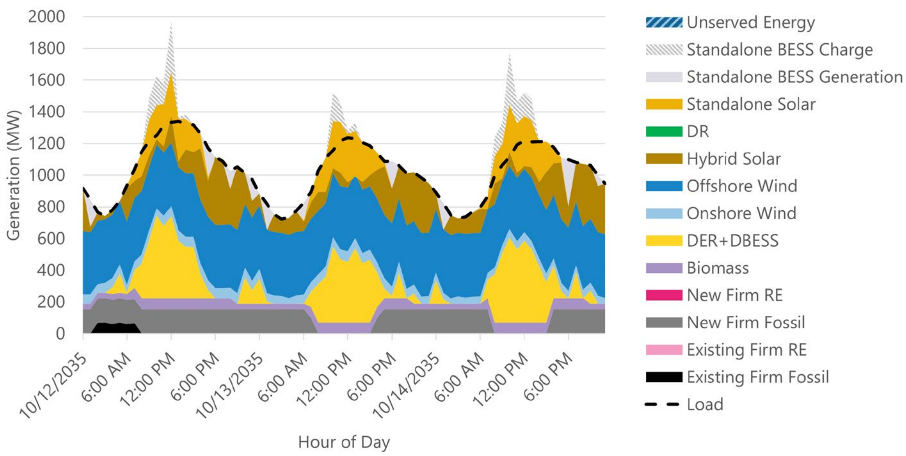


Figure 8-13. O'ahu: detailed Land-Constrained energy profile, 2035 median load day (October 12–14, 2035)

8.2.3.4 Operations of Firm Generation

We can gather insights into the changing role of firm generation by evaluating the number of starts of different types of firm generators and the amount those generators run, or the capacity factor, which is the percentage of hours a generator runs based on its rated capacity. The number of starts and capacity factor, respectively, of the utility-owned thermal generators for the Status Quo, Base, and Land-Constrained resource plans in 2030 and 2035 are shown in Figure 8-14 and Figure 8-15. Capacity factor was averaged for generators with similar operating characteristics. Because the Base resource plan adds more renewable resources in those years than the Land-Constrained plan, the generators have lower capacity factor and starts. Because the Status Quo plan doesn't add any new resources in the future, it has higher capacity factor and starts than the Base and Land-Constrained resource plans.

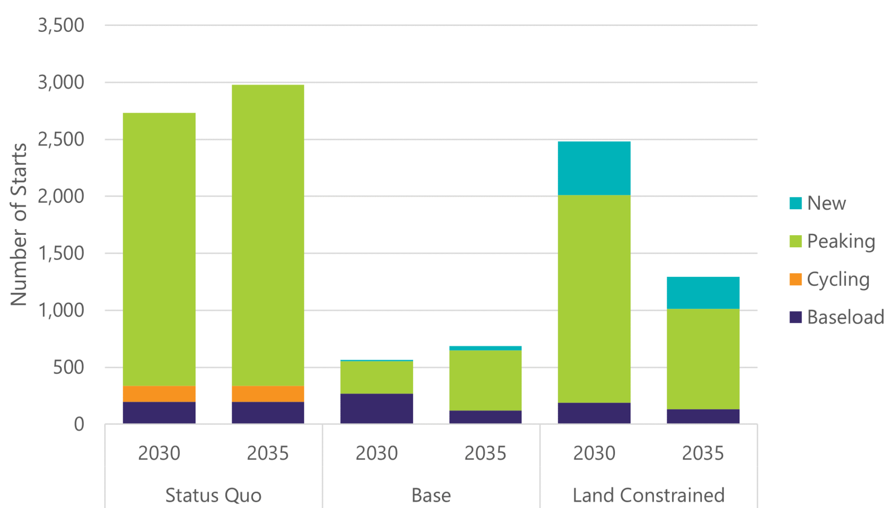


Figure 8-14. O'ahu: utility-owned thermal generators number of starts, 2030 and 2035 for Status Quo, Base, and Land-Constrained scenarios

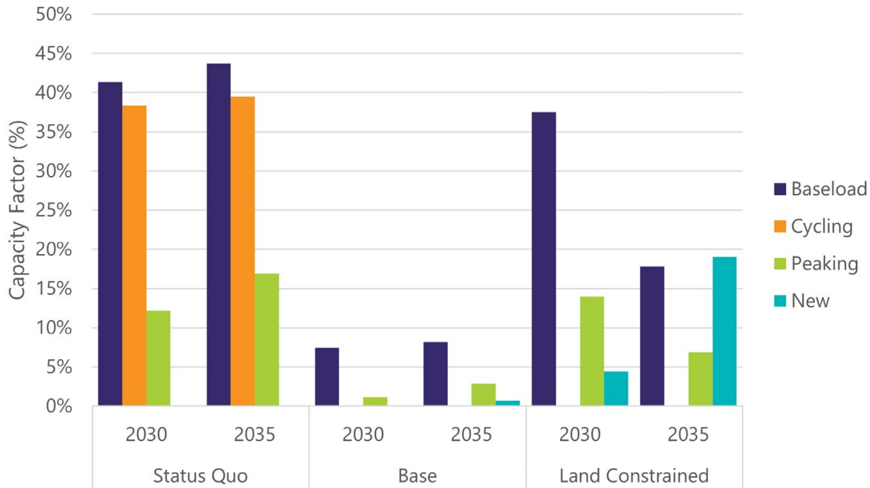


Figure 8-15. O'ahu: utility-owned thermal generators capacity factor, 2030 and 2035 for Status Quo, Base, and Land-Constrained scenarios

8.2.4 Transmission and System Security Needs

We analyzed the O'ahu Base, Land-Constrained, and High electricity demand resource plans to determine transmission and system security needs by performing steady-state and dynamic stability analyses for selected years with major large-scale resource additions, including:

- O'ahu system Base scenario resource plan and Land-Contrained scenario resource plan: 2030, 2035, 2046, and 2050
- O'ahu system High Load scenario resource plan: 2030 and 2035

8.2.4.1 Summary of Base Scenario Resource Plan

In the near term, it is unlikely that the O‘ahu transmission system will require transmission network expansion, but beyond 2040 both the interconnection of large-scale generation projects from REZ development and system load increase would trigger transmission network expansion.

It will be important to consider large-scale battery energy storage, energy efficiency, demand response, and distributed energy resources to reduce loading in the urban core to avoid overloading 138 kV overhead and underground lines. Additionally, the western part of the system already has major generation stations, and further large-scale renewable resources located on the west side of the island would cause generation congestion on the 138 kV system when a contingency of losing one or multiple transmission lines occurs. It is important to note that full development of renewable energy zones on the north shore of the island would require significant transmission network expansion around the Wahiawa 138 kV substation, which is simliar to what was found in the 2021 REZ study report.

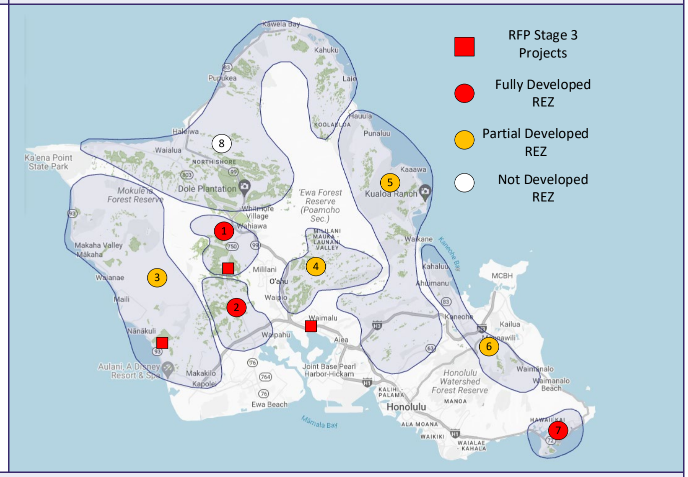
For system stability condition in future years, as a result of interconnecting large quantities of hybrid solar with grid-forming control, system stability performance is well within planning criteria. However, system stability performance is highly dependent on future grid-forming resources procured from the development of renewable energy zones. It is strongly recommended to continue to procure resources with grid-forming capability, and provide specific control recommendations during project interconnection requirement studies.

The following tables summarize the study results for the select years of the O‘ahu Base scenario resource plan.

Summary	
Studied resource plan	Studied year
Base scenario resource plan	2030

By 2030, the O‘ahu system will have new generation from Stage 3 O‘ahu RFP procurement and initial REZ development. Specifically, there will be 450 MW RDG and 300 MW firm generation procured through the Stage 3 O‘ahu RFP activity; 510 MW RDG development from renewable energy zones 1, 2, and 7; and 543 MW RDG development from renewable energy zones 3, 4, 5, and 6. Most of this new generation will be interconnected at the O‘ahu 138 kV system. The REZ development is expected to have both solar and wind generation.

In this time frame, it is also planned to remove 371 MW generation from the Waiau power plant.

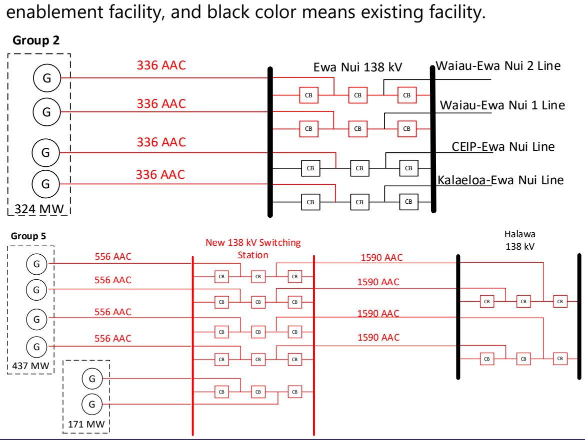


System Resource Summary and Forecasted Demand (MW)

Firm generation	Onshore standalone wind	Standalone grid-scale solar	Grid-scale hybrid solar/BESS	Standalone BESS	DER	System peak load
1,462	257	168	1,573	219	1,171	1,364

REZ Enablement

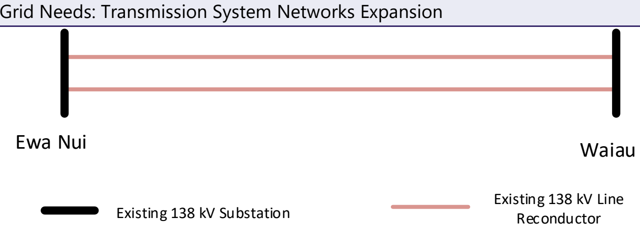
Examples of REZ enablement are shown as following for zones with lower MW potential (upper) and higher MW potential (lower). Red color means new enablement facility, and black color means existing facility.



REZ Enablement Cost Estimate

Renewable energy zone	1	2	3	4	5	6	7
Cost ($MM) per MW	0.21	0.27	1.32	0.82	1.51	0.62	N/A
REZ enablement ($MM)	24.6	87.6	448.4–819.9				N/A

Grid Needs: Transmission System Networks Expansion

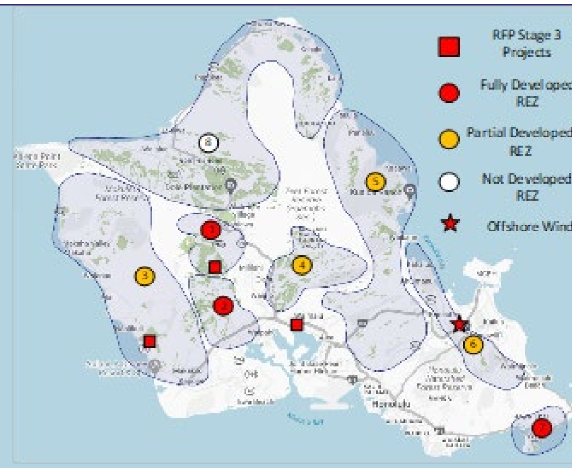


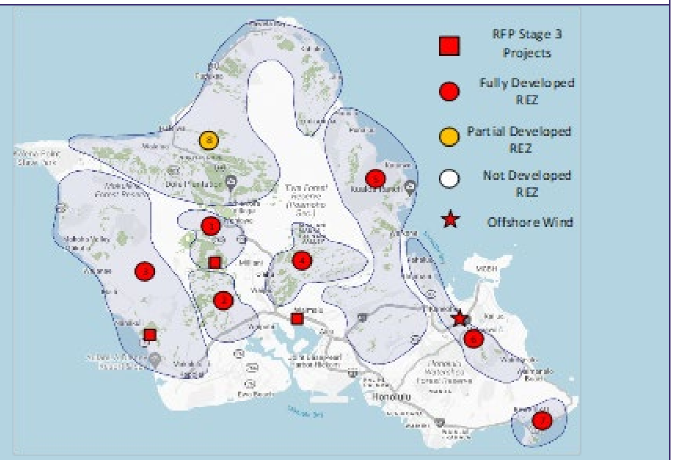
Network expansion cost estimate	$161.4 million

Alternative for this conductor upgrade will be to reduce Ewa Nui REZ generation interconnection from 324 MW to 175 MW.

Grid Needs: System Stability Needs

Grid has sufficient grid-forming resources to maintain system stability but the system must be operated so that grid-forming headroom/DER generation ratio is at least 0.7.

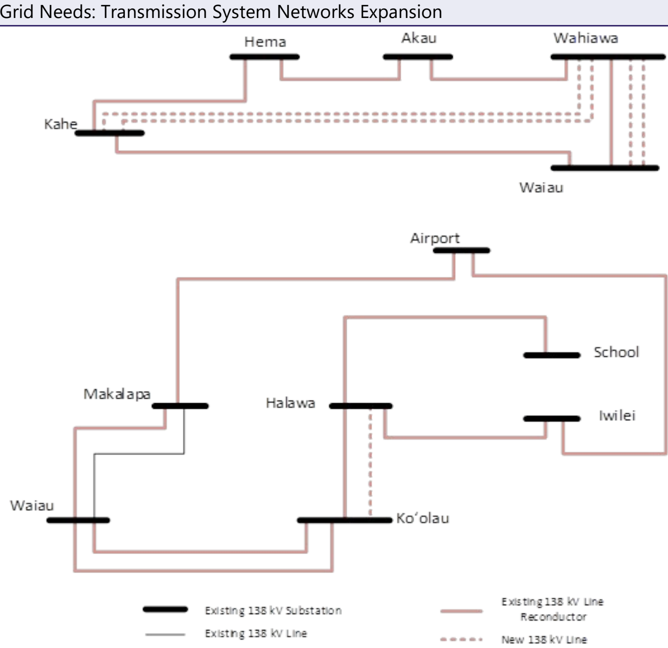
<table>
<tr><th colspan="8">Summary</th></tr>
<tr><td colspan="4">Studied resource plan</td><td colspan="4">Studied year</td></tr>
<tr><td colspan="4">Base scenario resource plan</td><td colspan="4">2035</td></tr>
<tr><td colspan="4">In addition to previous system resource changes by 2030, by 2035, the O'ahu system will have 64 MW large-scale standalone battery energy storage and 509 MW offshore wind. There is no further development of renewable energy zones. We assumed there will be 208 MW firm generation procured and interconnected at the Kalaeloa substation.</td><td colspan="4">
</td></tr>
<tr><td colspan="8">System Resource Summary and Forecasted Demand (MW)</td></tr>
<tr><td>Firm generation</td><td>Onshore standalone wind</td><td>Offshore wind</td><td>Standalone grid-scale solar</td><td>Grid-scale hybrid solar</td><td>Standalone BESS</td><td>DER</td><td>System peak load</td></tr>
<tr><td>1,297</td><td>257</td><td>509</td><td>157</td><td>1,573</td><td>282</td><td>1,295</td><td>1,432</td></tr>
<tr><td colspan="8">REZ Enablement</td></tr>
<tr><td colspan="8">There is no REZ development between 2031 and 2035. In this time frame, the development that requires interconnection facility is the 509 MW offshore wind, which requires expansion of the Ko'olau substation by adding four breakers and a half bay for the offshore wind interconnection. The cost estimate is $50.6 million.</td></tr>
<tr><td colspan="8">Grid Needs: Transmission System Networks Expansion</td></tr>
<tr><td colspan="8">None. But high conductor loading is observed on multiple 138 kV overhead conductors. It is recommended to reduce large-scale generation interconnection at Ko'olau substation by 10 MW.</td></tr>
<tr><td colspan="8">Grid Needs: System Stability Needs</td></tr>
<tr><td colspan="8">Grid has sufficient grid-forming resources to maintain system stability, but the system must be operated so that grid-forming headroom/DER generation ratio is at least 0.70.</td></tr>
</table>

Summary	
Studied resource plan	Studied year
Base scenario resource plan	2045
In addition to previous system resource changes, by 2045, the O'ahu system will finish developing the majority of renewable energy zones 1, 2, 3, 4, 5, 6, and 7, with only 106 MW potential remaining undeveloped. Meanwhile, 452 MW solar potential of renewable energy zone 8 will be developed by 2045. System load is forecasted with significant growth: 1,692 MW peak demand at 2046. Both REZ development and system load growth drive large amount of O'ahu transmission system network expansion.	

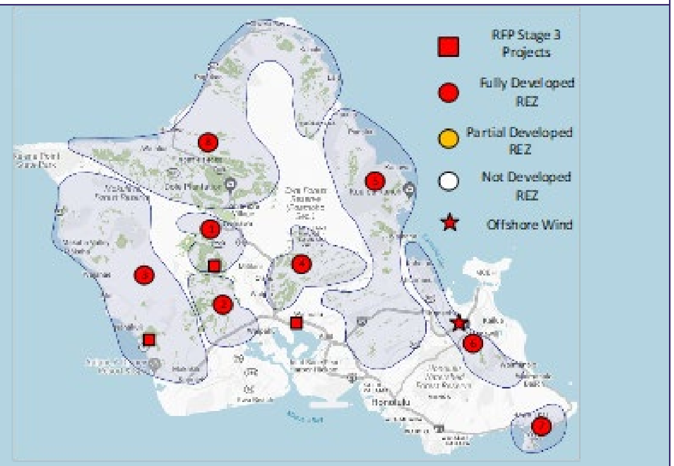
System Resource Summary and Forecasted Demand (MW)							
Firm generation	Onshore standalone wind	Offshore wind	Standalone grid-scale solar	Grid-scale hybrid solar	Standalone BESS	DER	System peak load
1,126	287	509	441	2077	315	1,454	1,692

REZ Enablement					
Renewable energy zone	3	4	5	6	8
Cost ($MM) per MW	1.32	0.82	1.51	0.62	1.25
REZ enablement ($MM)	1084.6–1468.5				565.0

Grid Needs: Transmission System Networks Expansion



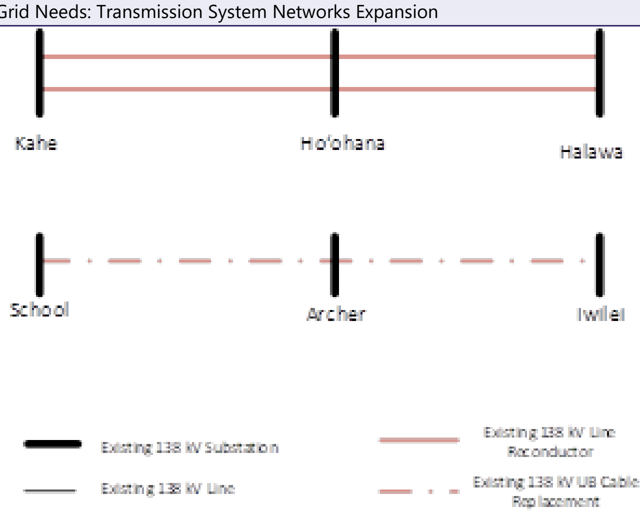
Network expansion cost estimate	$3,980.5 million
Grid Needs: System Stability Needs	
Not studied.	

Summary	
Studied resource plan	Studied year
Base scenario resource plan	2050
By 2050, 3,344 MW of all eight renewable energy zones are fully developed. System load is forecasted with significant growth: 1,829 MW peak demand at 2050, which could possibly cause underground cable replacement for 138 kV underground cable among School Street, Iwilei, and Archer 138 kV substations. All Kahe fossil fuel–based generation units are retired by 2050. Besides switching fossil fuel to biodiesel fuel for remaining firm units, 135 MW new firm units will be added to the O‘ahu system by 2050.	

System Resource Summary and Forecasted Demand (MW)							
Firm generation	Onshore standalone wind	Offshore wind	Standalone grid-scale solar	Large-scale hybrid solar	Standalone BESS	DER	System peak load
1,010	287	509	480	3,558	333	1,497	1,829

REZ Enablement					
Renewable energy zone	3	4	5	6	8
Cost ($MM) per MW	1.32	0.82	1.51	0.62	1.25
REZ enablement ($MM)	86.9–160.1				892.5

Grid Needs: Transmission System Networks Expansion



Network expansion cost estimate	$1,208.9 million

Reducing load from 138 kV substations Kamoku, Kewalo, and Archer by 37 MW can avoid cable replacement for the 138 kV underground cable Archer-School, Archer-Iweilei. This can be realized by adding generation such as large-scale energy storage in those substations, or procure demand response on circuits supplied by those substations, or implmenting an EE program.

Full development of the north shore renewable energy zone (i.e., zone 8) would also cause overloadings on the 138 kV lines connected with Wahiawa substation. By reducing generation interconnection size at Wahiawa substation by 220 MW, the line overloading will be mitigated.

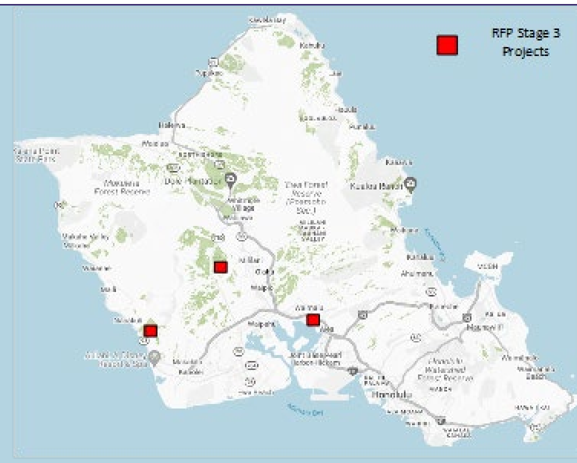
Grid Needs: System Stability Needs

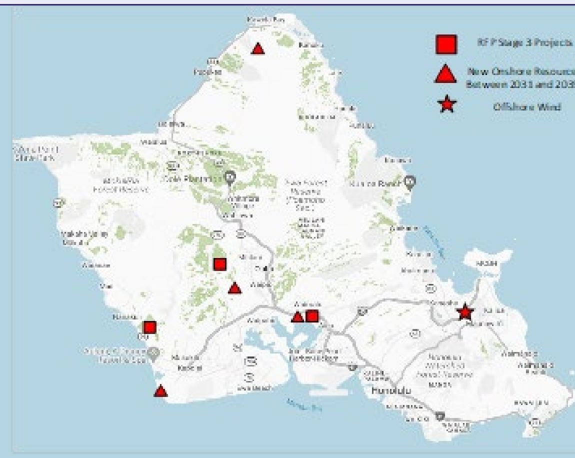
Not studied.

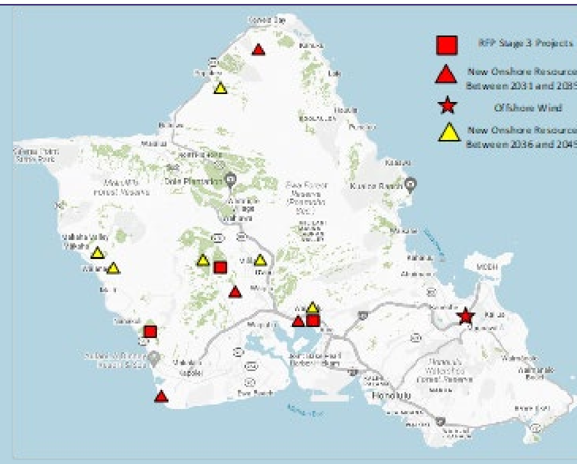
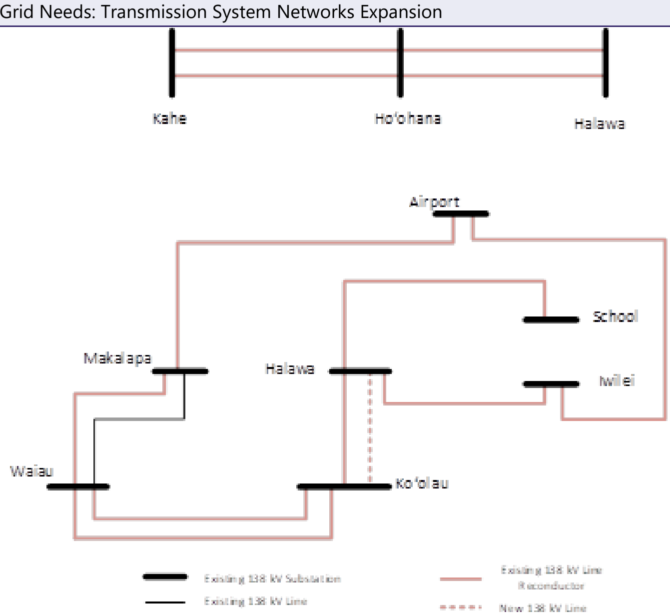
8.2.4.2 Summary of Land-Constrained Scenario Resource Plan

The Land-Constrained scenario resource plan requires much less transmission network expansion needed compared to the Base scenario resource plan. Still, it is suggested to install a large-scale BESS project on the east side of the island, close to the urban core load center, to avoid 138 kV overhead line or underground cable overloading.

Because of the limited amount of large-scale resources in the Land-Constrained scenario, it is likely that additional large-scale grid-forming resources will be needed (i.e., retrofit of existing renewable plants or new standalone energy storage) to maintain system stability within the Oʻahu transmission planning criteria. The study recommends that the minimum requirement of available MW headroom from large-scale grid-forming resource should be 70% of DER generation.

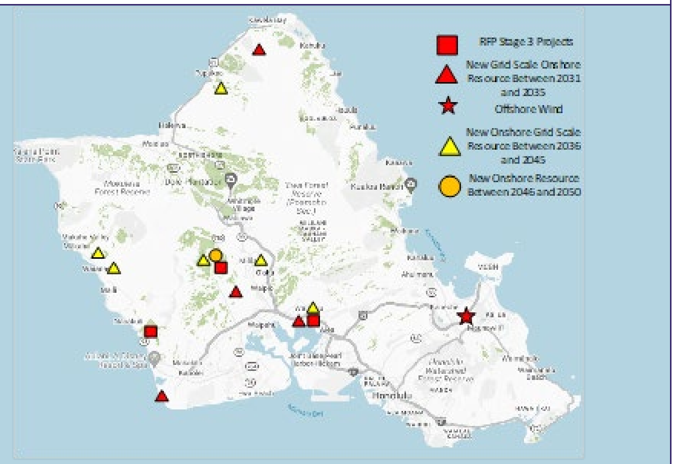
<table>
<tr><th colspan="7">Summary</th></tr>
<tr><td colspan="3">Studied resource plan</td><td colspan="4">Studied year</td></tr>
<tr><td colspan="3">Land-Constrained scenario resource plan</td><td colspan="4">2030</td></tr>
<tr><td colspan="3">By 2030, the Oʻahu system will have all new generation from Stage 3 Oʻahu procurement on the transmission and sub-transmisison side. Specifically, there will be 450 MW RDG and 300 MW firm generation procured through the Stage 3 Oʻahu RFP. Most of these new resources are expected to be interconnected at the Oʻahu 138 kV system. In this time frame, it is also planned to remove 371 MW generation from the Waiau power plant.</td><td colspan="4">
</td></tr>
<tr><td colspan="7">System Resource Summary and Forecasted Demand (MW)</td></tr>
<tr><td>Firm generation</td><td>Onshore standalone wind</td><td>Standalone grid-scale solar</td><td>Large-scale hybrid solar</td><td>Standalone BESS</td><td>DER</td><td>System peak load</td></tr>
<tr><td>1,462</td><td>123</td><td>168</td><td>684</td><td>135</td><td>1,171</td><td>1,364</td></tr>
<tr><td colspan="7">Grid Needs: Transmission System Networks Expansion</td></tr>
<tr><td colspan="7">None</td></tr>
<tr><td colspan="7">Grid Needs: System Stability Needs</td></tr>
<tr><td colspan="7">System may need more grid-forming resource, and it is recommended to maintain MW headroom of grid-forming resource/DER generation ratio of at least 0.7. If the ratio cannot be maintained, it is recommended to dispatch more synchronous machine resources to create more headroom from the grid-forming resource, or curtail DER generation.</td></tr>
</table>

Summary							
Studied resource plan				Studied year			
Land-Constrained scenario resource plan				2035			
In addition to previous system resource changes by 2030, by 2035, the O'ahu system will have 105 MW large-scale standalone battery energy storage and 400 MW offshore wind. 153 MW firm resource will also be added to the system by 2035. There will be 208 MW firm generation procured and interconnected at the Kalaeloa substation. 30 MW wind will be added to the system to meet the system demand.							
System Resource Summary and Forecasted Demand (MW)							
Firm generation	Onshore standalone wind	Offshore wind	Standalone grid-scale solar	Large-scale hybrid solar	Standalone BESS	DER	System peak load
1,450	123	400	157	684	240	1,295	1,432
Grid Needs: Transmission System Networks Expansion							
None							
Grid Needs: System Stability Needs							
System may need more grid-forming resources, and it is recommended to maintain MW headroom of grid-forming resource/DER generation ratio of at least 0.7. If the ratio cannot be maintained, it is recommended to dispatch more synchronous machine-based resource to create more headroom from the grid-forming resource.							

<table>
<tr><th colspan="8">Summary</th></tr>
<tr><td colspan="4">Studied resource plan</td><td colspan="4">Studied year</td></tr>
<tr><td colspan="4">Land-Constrained scenario resource plan</td><td colspan="4">2045</td></tr>
<tr><td colspan="4">In addition to previous system resource changes, by 2045, the O’ahu system will add another 153 MW firm generation into the system. Also, 169 MW standalone solar and 93 MW wind development from retired solar and wind locations will be completed by 2045. 169 MW new large-scale standalone battery energy storage will be interconnected to the system from transmission substations. System load is forecasted with significant growth: 1,692 MW peak demand at 2046. On the distribution side, 783 MW distributed energy resources coupled with 1,567 MWh distributed energy storage will be added to the system to supply system load demand.</td><td colspan="4">
</td></tr>
<tr><td colspan="8">System Resource Summary and Forecasted Demand (MW)</td></tr>
<tr><td>Firm generation</td><td>Onshore standalone wind</td><td>Offshore wind</td><td>Standalone grid-scale solar</td><td>Grid-scale hybrid solar/BESS</td><td>Standalone BESS</td><td>DER</td><td>System peak load</td></tr>
<tr><td>1,432</td><td>123</td><td>400</td><td>169</td><td>684</td><td>399</td><td>3,020</td><td>1,692</td></tr>
<tr><td colspan="8">Grid Needs: Transmission System Networks Expansion</td></tr>
<tr><td colspan="8">
</td></tr>
<tr><td colspan="6">Network expansion cost estimate</td><td colspan="2">$2,291.6 million</td></tr>
<tr><td colspan="8">Grid Needs: System Stability Needs</td></tr>
<tr><td colspan="8">The dynamic stability study was not performed. However, according to the available grid-forming resource and significant DER additions, the system may require more large-scale grid-forming resources. This could be more grid-forming energy storage interconnected on the subtransmission or transmission grid, or grid-forming STATCOM interconnected on the transmission grid.</td></tr>
</table>

Summary	
Studied resource plan	Studied year
Land-Constrained scenario resource plan	2050

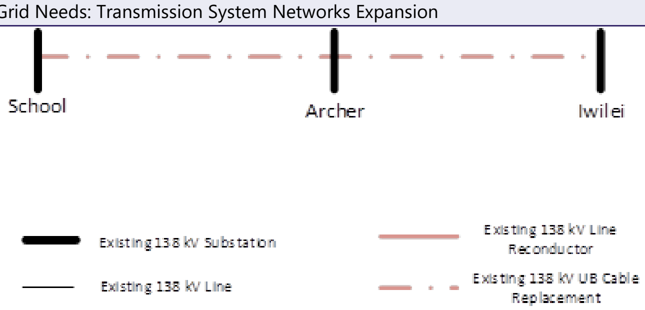
From 2046 to 2050, the only large-scale resource added to the O’ahu system as planned is a 119 MW/1,110 MWh large-scale battery energy storage system. Kahe 5 and 6, the only remaining fossil fuel–based generation at Kahe power plant, will be retired in 2050. It is also planned to add 1,017 MW distributed energy resources, coupled with 2,033 MWh distributed energy storage on the distribution system. System peak load is forecasted to be 1,829 MW by 2050. The load increase will require conductor upgrade to replace the 138 kV underground conductor Archer-School and Archer-Iwilei.



System Resource Summary and Forecasted Demand (MW)

Firm generation	Onshore standalone wind	Offshore wind	Standalone grid-scale solar	Grid-scale hybrid solar/BESS	Standalone BESS	DER	System peak load
1,163	123	400	169	684	519	5,097	1,829

Grid Needs: Transmission System Networks Expansion



Networks expansion cost estimate	$345.1 million

Reducing load from 138 kV substations Kamoku, Kewalo, School St., and Iwilei by 20 MW can avoid cable replacement for the 138 kV underground cables Archer-School and Archer-Iweilei. This can be realized by adding generation such as large-scale battery energy storage at those substations, acquiring demand response on circuits supplied by those substations, or implementing a targeted EE program.

Grid Needs: System Stability Needs

The dynamic stability study for this scenario was not performed. However, the recommendation for the O’ahu system regarding system stability needs is simliar to what is recommended for the 2045 scenario.

8.2.5 Distribution Needs

This section discusses distribution needs as they pertain to the grid needs assessment for O‘ahu.

8.2.5.1 Hosting Capacity Grid Needs

Of the 384 circuits assessed on O‘ahu, most have sufficient DER hosting capacity or could accommodate the 5-year hosting capacity without infrastructure investments. The remaining circuits where infrastructure investments are required to increase hosting capacity to accommodate the forecasted distributed energy resources are identified as requiring grid needs. Infrastructure investments or distribution upgrades (i.e., wires solutions) to mitigate the grid needs are identified with cost estimates. The grid needs and solutions are summarized in Table 8-6.

Table 8-6. O‘ahu Hosting Capacity Grid Needs (Years 2021–2025)

Parameter (Nominal $)	Base DER Forecast	High DER Forecast	Low DER Forecast
Number of grid needs	6	16	5
Cost summary (wires solutions)	$792,000	$3,895,000	$648,000

A complete list of the hosting capacity grid needs can be found in the *Distribution DER Hosting Capacity Grid Needs* report.

8.2.5.2 Location-Based Grid Needs

Of the 393 circuits and 204 substation transformers assessed on O‘ahu, most have sufficient capacity to accommodate the forecasted load demand. For substation transformers and circuits where there is insufficient capacity, a grid need is identified. Infrastructure investments or distribution upgrades (i.e., wires solutions) to mitigate the grid needs are identified with cost estimates. The grid needs and solutions are summarized in Table 8-7.

A complete list of the load-driven grid needs can be found in Appendix E.

Table 8-7. O‘ahu Location-Based Grid Needs (Years 2023–2030)

Parameter (Nominal $)	Scenario 1 (Base)	Scenario 2 (High Load)	Scenario 3 (Low Load)	Scenario 4 (Faster Technology Adoption)
Number of grid needs	22	41	19	29
Cost summary (wires solutions)	$95,724,000	$152,426,000	$77,900,000	$165,934,000

8.2.5.3 Distribution Grid Needs Summary

The minimum number of grid needs identified (i.e., minimum wires solutions) by scenario by island is shown in Table 8-8 below. This includes both hosting capacity and location-based grid needs.

Table 8-8. O‘ahu Minimum Grid Needs Solutions Identified (Years 2023–2030)

Island (Nominal $)	Scenario 1 (Base)	Scenario 2 (High Load)	Scenario 3 (Low Load)	Scenario 4 (Faster Technology Adoption)
Number of grid needs	18	30	26	30
Cost summary (wires solutions)	$51,806,000	$68,225,000	$52,097,000	$59,999,000

8.2.5.4 NWA Opportunities

Results of applying the NWA opportunity evaluation methodology described in Section 8.1.4.5 are summarized in Table 8-9 through Table 8-12 below for O'ahu by scenario.

Base Scenario

Table 8-9. O'ahu NWA Opportunity Projects by Track: Base

Track	Operating Date	Transformer	Circuit	Description	Cost (Nominal $)
1 (qualified: procurement likely)	2025	CEIP 3	CEIP 46	Reconductor	$3,930,000
	2026	Kapolei 2	Kapolei 4	Circuit line extension	$2,091,000
	2026	Wahiawa 3 (138 kV)	Wahiawa-Waimano	New substation transformer and circuit	$15,012,000
	2027	Kamokila 2	N/A	Circuit line extension	$1,914,000
	2027	Kewalo T3	N/A	New substation transformer	$6,404,000
2 (qualified: pricing approach or re-evaluate later)	2028	Kuilima 2	N/A	New substation transformer	$3,160,000
3 (non-qualified)	2025	Waipio 1	N/A	New substation transformer	$2,880,000

High Load Customer Technology Adoption Bookend Scenario

Table 8-10. O'ahu NWA Opportunity Projects by Track: High Load Customer Technology Adoption Bookend

Track	Operating Date	Transformer	Circuit	Description	Cost (Nominal $)
1 (qualified: procurement likely)	2025	Ewa Nui 2	Ewa Nui 2	New substation transformer and circuit	$3,634,000
	2026	Kuilima 2	N/A	New substation transformer	$2,970,000
	2027	Kewalo T3	N/A	New substation transformer	$6,404,000
2 (qualified: pricing approach or reevaluate later)	2025	Kamokila 2	N/A	Circuit line extension	$2,480,000
	2028	CEIP 2	CEIP 3	Circuit line extension	$5,072,000
	2028	Fort Weaver 1	N/A	New substation transformer	$3,160,000
	2028	Hauula	Hauula	Reconductor	$780,000
3 (non-qualified)	2025	Kapolei 2	Kapolei 4	New substation transformer and circuit	$3,684,000
	2025	Piikoi 4	Piikoi 8	Reconductor	$270,000
	2025	Wahiawa 3 (138 kV)	Wahiawa-Waimano	New substation transformer and circuit	$15,012,000
	2028	Kahuku	Kahuku	Reconductor	$187,000
	2028	Kunia Makai 1	N/A	New switch and transfer load	$26,000
	2029	Ewa Nui 1	Ewa Nui 1	Circuit line extension	$149,000
	2029	Hoaeae 1	Hoaeae 1	New switch	$25,000
	2029	Kaneohe 1	Heeia	Transfer load	$26,000
	2029	Puunui 2	Heights	Reconductor, voltage regulator, and fuse resizing	$473,400
	2030	Makaha 2	N/A	New switch	$26,000

Low Load Customer Technology Adoption Bookend Scenario

Table 8-11. Oʻahu NWA Opportunity Projects by Track: Low Load Customer Technology Adoption Bookend

Track	Operating Date	Transformer	Circuit	Description	Cost (Nominal $)
1 (qualified: procurement likely)	2027	Kewalo T3	N/A	New substation transformer	$6,404,000
2 (qualified: pricing approach or reevaluate later)	2028	CEIP 2	CEIP 3	Circuit line extension	$5,072,000
	2028	Wahiawa 3 (138 kV)	N/A	New substation transformer and circuit	$15,012,000
	2029	Kuilima 2	N/A	New substation transformer	$3,260,000
3 (non-qualified)	2025	Waialae 1 4 kV	Wai-Wilhelmina	Install two 1ph line regulators	$140,000
	2025	Waimanalo Bch 1	Waimanalo	Dynamic LTC	$154,000

Faster Technology Adoption Bookend Scenario

Table 8-12. Oʻahu NWA Opportunity Projects by Track: Faster Technology Adoption Bookend

Track	Operating Date	Transformer	Circuit	Description	Cost (Nominal $)
1 (qualified: procurement likely)	2026	Kamokila 2	N/A	Circuit line extension	$1,857,999
	2026	Kapolei 2	Kapolei 4	Circuit line extension	$2,091,012
	2026	Wahiawa 3 (138 kV)	N/A	New substation transformer and circuit	$15,012,000
	2027	Barbers Pt Tank Farm 2	Industrial	Circuit line extension	$5,071,920
	2027	CEIP 3	CEIP 46	Reconductor	$3,930,000
	2027	Kewalo T3	N/A	New substation transformer	$6,404,000
2 (qualified: pricing approach or re-evaluate later)	2029	Kuilima 2	N/A	New substation transformer	$3,260,000
3 (non-qualified)	2025	CEIP 2	CEIP 3	New switch	$23,330
	2025	Waialae 1 4 kV	Wai-Wilhelmina	Install two 1ph line regulators	$140,000
	2025	Waimanalo Bch 1	Waimanalo	Dynamic LTC	$154,000

8.2.6 Preferred Plan

The capacity expansion modeling conducted in RESOLVE was the starting point for identifying grid needs and developing a resource plan. Probabilistic resource adequacy analyses were then performed to confirm that the portfolio of resources selected in the resource plan were reliable. Based on the results of this analysis, the following changes were made:

- Removed the 153 MW combined cycle selected in 2035 in the Land-Constrained scenario as the system met the loss of load standard without this resource. Removed the 20 MW biomass selected in 2045 in the Base scenario.
- Increased duration of paired and standalone BESS to 4 hours to match current market conditions.
- Updated the Stage 3 RFP variable renewable proxy to reflect the current target, which was adjusted for the withdrawal of Barber's Point Solar.

In parallel, transmission and system security needs were identified, including reductions in the REZ buildout as an NWA to additional transmission expansion. Based on the results of this analysis, the following changes were made:

- Base scenario
  - 2027: 70% grid-forming headroom capacity for dynamic stability
  - 2030: reduce Ewa Nui Group 1 renewable energy zone by 150 MW to avoid conductor overloads
  - 2036: reduce Koolau Group 2 renewable energy zone by 10 MW to avoid conductor overloads
  - 2050: reduce Wahiawa Group 3 renewable energy zone by 220 MW to avoid conductor overloads
- Land-Constrained scenario
  - 2027: 70% grid-forming headroom capacity for dynamic stability
  - 2050: limit Ewa Nui BESS in Group 1 renewable energy zone and Hoʻohana battery energy storage to less than or equal to 142 MW

Additional capital costs were identified to interconnect resources in the renewable energy zones selected in RESOLVE. While the REZ enablement costs were already included as part of the RESOLVE modeling, they are listed here in Table 8-13 for completeness alongside new network expansion costs.

The Status Quo and Land-Constrained scenario transmission network expansion costs reflect estimated transmission needed to expand capacity, as identified in the transmission needs analysis, to serve load growth because of electrification of transportation.

Table 8-13. Oʻahu Transmission Capital Costs

Nominal Transmission Costs ($MM)	Base		Land Constrained		Status Quo	
Year	REZ Enablement	Network Expansion	REZ Enablement	Network Expansion	REZ Enablement	Network Expansion
2029	$114	-	$62	-	-	-
2030	$942	-	-	-	-	-
2035	$62	-	-	-	-	-
2040	$799	-	-	-	-	-
2045	$2,241	$3,482	-	$1,991	-	$529
2050	$1,112	$1,018	-	$293	-	$293

Table 8-14 and Table 8-15 show a comparison of Oʻahu Base and Land-Constrained scenarios, respectively, production costs with and without transmission constraints.

Comparing the production costs with and without the transmission constraints identified above shows that in the Land-Constrained scenario without REZ development, the dynamic stability requirement does not significantly change production costs. In the Base scenario, the reductions in REZ buildout cause higher production costs that would be offset by reduced capital costs for new transmission.

Table 8-14. Comparison of Oʻahu Base Scenario Production Costs with and without Transmission Constraints

NPV ($MM)	With Transmission Constraints	Without Transmission Constraints
(2023–2050)	$16,710	$15,869

Table 8-15. Comparison of Oʻahu Land-Constrained Scenario Production Costs with and without Transmission Constraints

NPV ($MM)	With Transmission Constraints	Without Transmission Constraints
(2023–2050)	$19,439	$19,446

8.3 Hawai'i Island

This section describes the results of the grid needs assessment for Hawai'i Island through the multistep process that includes modeling capacity expansion, resource adequacy, operations of the system, transmission and system security needs, distribution needs, and iterations or adjustments made to determine the preferred plan.

8.3.1 Capacity Expansion Scenarios

In the Base scenario shown in Figure 8-16, initially onshore wind and standalone energy storage are selected. As electricity demand increases over time, the model selects geothermal and hybrid solar as part of the optimal plan. The Low electricity demand scenario selects only onshore wind and standalone energy storage. The Faster Technology Adoption and High electricity demand scenarios select new firm resources in addition to larger quantities of new resources than in the Base scenario. Existing fossil fuel–based resources are shown as firm renewable resources in 2050 because of their switch to biofuels in 2045. All scenarios achieve their RPS targets with consistent increases in the use of renewable resources.

The Hawai'i Island resource portfolio has the most diverse set of resources of any island. This includes solar, wind, energy storage, geothermal, and hydroelectric power. Together these resources will greatly reduce the reliance on fossil fuel–based generators, achieving near 100% renewable energy by 2030. Though the forecast generation varies over the range of scenarios, the types of resources used are consistent, as shown in Figure 8-16.

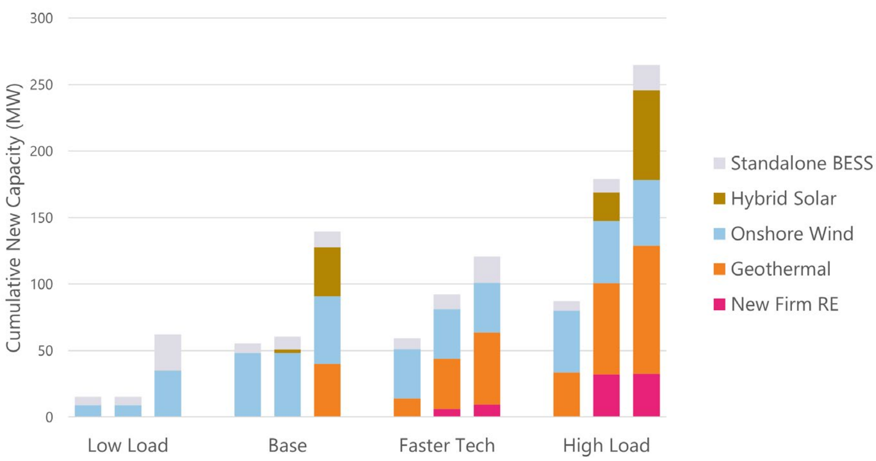


Figure 8-16. Hawai'i Island: cumulative new capacity selected by RESOLVE in 2030, 2035, and 2050 for the Base, Low Load, High Load, and Faster Technology Adoption scenarios

Figure 8-17 shows each resource type's contribution to the system's annual generation. Even though new firm generators are sometimes selected for capacity reasons, they are rarely used even in the High Load scenario.

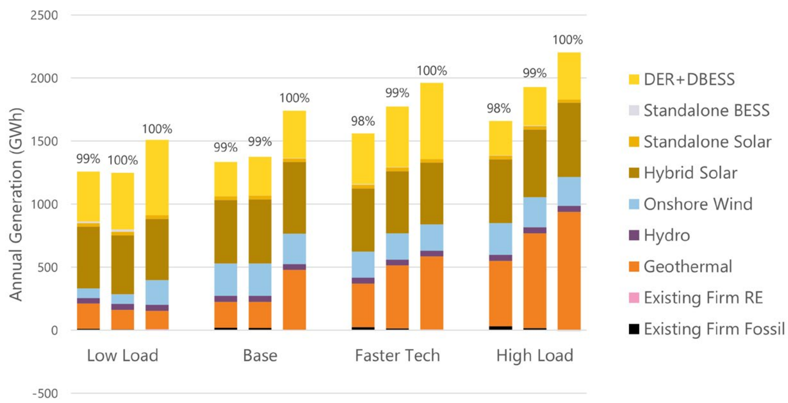


Figure 8-17. Hawai'i Island: annual generation and RPS from resources in 2030, 2035, and 2050 for the Base, Low Load, High Load, and Faster Technology Adoption scenarios

8.3.1.1 High Fuel Retirement Optimization Scenario

In addition to the planned retirements of Hill 5 and Hill 6 and with Puna Steam on standby status, the High Fuel Retirement Optimization scenario chooses to retire an additional 54 MW of thermal capacity (see Figure 8-18). Because RESOLVE performs a linear optimization, the additional retirements may consist of partial unit retirements. These additional retirements occur early in the planning horizon before 2030 and are replaced with new wind, geothermal, and firm resources. The Hamakua Energy Partners contract is assumed to expire by the end of 2030 for both the Base and High Fuel Retirement Optimization scenarios.

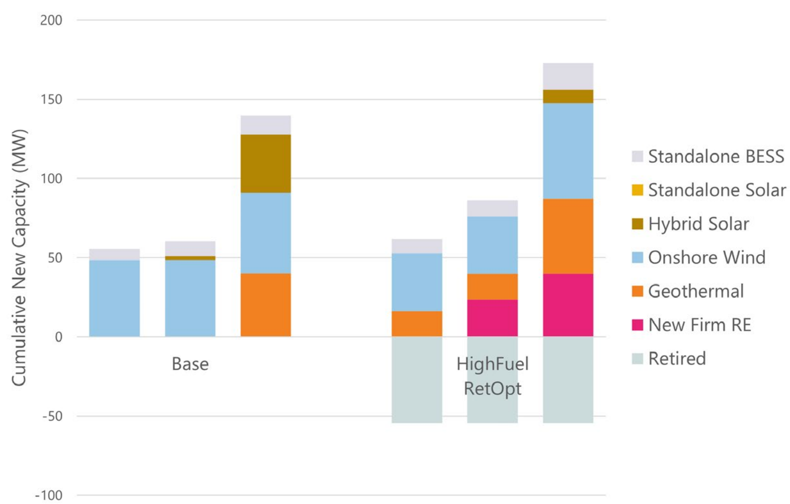


Figure 8-18. Hawai'i Island: cumulative new capacity selected by RESOLVE in 2030, 2035, and 2050 for the Base and High Fuel Retirement Optimization scenarios

Even with the additional retirements, the Optimized Retirement scenario annual generation is similar to the Base scenario annual generation as shown in Figure 8-19. It does not appear that the resource plan is particularly sensitive to high fuel costs; that is, the Base scenario significantly reduces our reliance on fossil fuel, and further opportunities to retire fossil fuel–based generators may be available as discussed in Section 12.

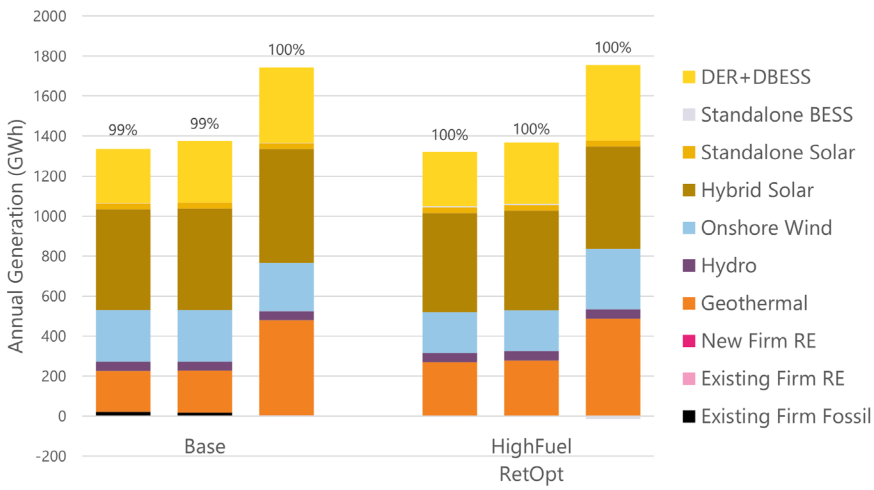


Figure 8-19. Hawai'i Island: annual generation and RPS from resources in 2030, 2035, and 2050 for the Base and High Fuel Retirement Optimization scenarios

8.3.2 Resource Adequacy

By 2030, 49 MW of existing fossil fuel–based generators are planned for deactivation and independent power producer Hamakua Energy Partners' PPA is set to expire at the end of 2030. In a Base scenario, the planned system is expected to withstand the loss of these resources. However, if Hawai'i Island is expected to be in a High electricity demand scenario by 2035, additional resources may need to be acquired or planned deactivations may be delayed.

For Hawai'i Island, Puna Steam is assumed on standby status and Hill 5 and 6 is assumed to be retired by 2027, as shown in Table 8-16. This is largely due to compliance with environmental (regional haze) regulations. If these units continue operation past that date, these generating units need to be retrofitted with environmental controls.

Table 8-16. Generating Unit Deactivation/Retirement Assumptions

Year	Generating Unit
2025	Puna Steam on standby (15.5 MW)
2027	Hill 5–6 removed from service (33.8 MW)

Probabilistic Resource Adequacy Summary

The planned Hawai'i Island system in 2030 is expected to meet the Base scenario system load assuming the planned deactivations through 2030 (see Table 8-17). Even if the Stage 3 procurement doesn't meet its target procurement, the 2030 Hawai'i Island system is expected to meet our reliability targets under the Base scenario.

Table 8-17. Probabilistic Analysis: Results Summary, Hawai'i Island, 2030

Scenario	Existing Firm (MW)	New Firm (MW)	Stage 3 RFP (MW)	Future Wind (MW)	Future Hybrid Solar (MW)	Future Standalone BESS (MW)	LOLE (Days/ Year)	LOLEv (Event/ Year)	LOLH (Hours/ Year)	EUE (MWh/ Year)	EUE (%)
Base, 2030	228	0	0	48	0	7/12	0.000	0.000	0.000	0.000	0.000

The planned Hawai'i Island system in 2035 is expected to meet the Base scenario load assuming the planned deactivations through 2035 (see Table 8-18). However, additional resources are needed in a High electricity demand scenario.

Table 8-18. Probabilistic Analysis: Results Summary, Hawaiʻi Island, 2035

Scenario	Existing Firm (MW)	New Firm (MW)	Stage 3 RFP (MW)	Future Wind (MW)	Future Hybrid Solar (MW)	Future Standalone BESS (MW)	LOLE (Days/ Year)	LOLEv (Event/ Year)	LOLH (Hours/ Year)	EUE (MWh/ Year)	EUE (%)
Base, 2035	228	0	0	48	0	7/12	0.076	0.144	0.220	0.002	0.000
High Load, 2035	228	0	140	0	0	0/0	28.9	64.2	149	4.70	0.454

The results show that, in 2030 and 2035, the Base plans developed by RESOLVE should meet our reliability targets. However, additional resources are needed if Hawaiʻi Island is in a High Load scenario. In 2030, assuming a Base scenario load forecast with Hamakua Energy Partners combined cycle already retired:

- Even without the full Stage 3 procurement target of 140 MW of hybrid solar, the 2030 system's loss of load expectation is less than 0.1 day per year.
- Though 140 MW of hybrid solar is not needed to meet the reliability target in 2030, acquiring even half of the 140 MW will greatly benefit the system.
- A loss of load less than 0.1 day per year is expected even if Hamakua Energy Partners combined cycle and some additional firm is brought offline unexpectedly.

In 2035, assuming a High electricity demand scenario and all 140 MW of hybrid solar from the Stage 3 RFP:

- Approximately 450 MW of additional hybrid solar is needed to bring the system loss of load expectation down below 0.1 day per year.
- Approximately 50 MW of additional firm generation is needed to bring the system loss of load expectation down below 0.1 day per year.

See Section 12 for more details on risks of the resource portfolio given uncertainties in procuring and acquiring the optimal mix of resources.

8.3.3 Grid Operations

The transition to 100% renewables will necessitate a change in how the thermal generators on our system operate. Scenarios with more renewable resources will use thermal generators less often. This is shown in the daily energy profiles and operational statistics in this section.

8.3.3.1 Status Quo Typical Operations

For the Hawaiʻi Island Status Quo scenario, Hamakua Energy Partners combined cycle, Hawi wind, Tawhiri wind, and Wailuku hydro are assumed to remain in service. Hill 5 and Hill 6, and Puna Steam are assumed to be retired with Puna Steam on standby status.

The dispatch of resources during the median load day as well as the day directly preceding and following the median load day of the Status Quo scenario in 2030 and 2035, respectively, are shown below in Figure 8-20 and Figure 8-21. This shows how the resource portfolio meets the system load over a typical few days during a given year.

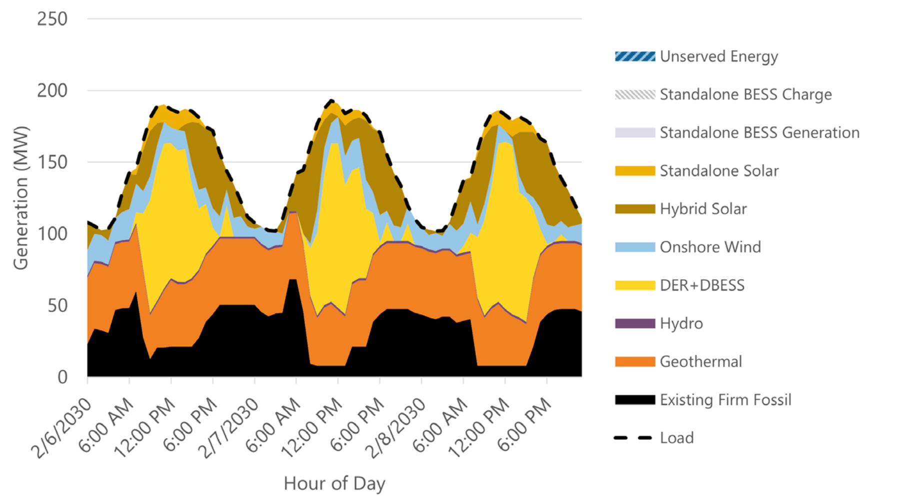


Figure 8-20. Hawai'i Island: detailed Status Quo energy profile, 2030 median load day (February 6–8, 2030)

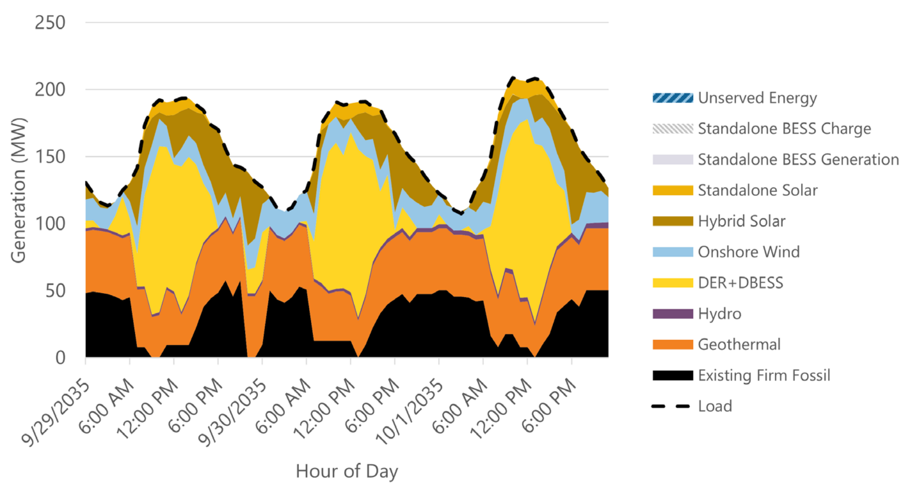


Figure 8-21. Hawai'i Island: detailed Status Quo energy profile, 2035 median load day (September 29–October 1, 2035)

8.3.3.2 Base Scenario Typical Operations

The dispatch of resources during the median load day as well as the day directly preceding and following the median load day of the Base scenario in 2030 and 2035, respectively, are shown below in Figure 8-22 and Figure 8-23. In the Base scenario, during midday, most of the load is expected to be met from variable renewable and geothermal resources. In 2030, firm fossil fuel–based generators are used primarily during morning and evening hours and by 2035 the system is effectively operating on 100% renewable energy.

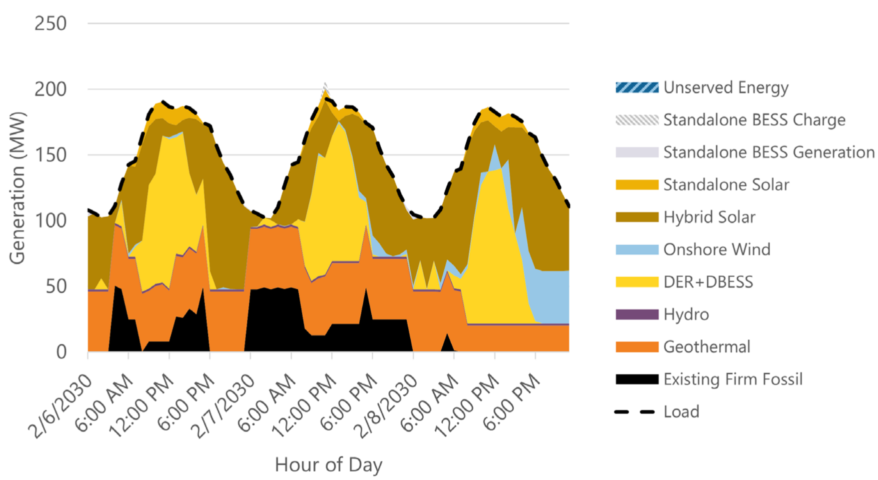


Figure 8-22. Hawai'i Island: detailed Base energy profile, 2030 median load day

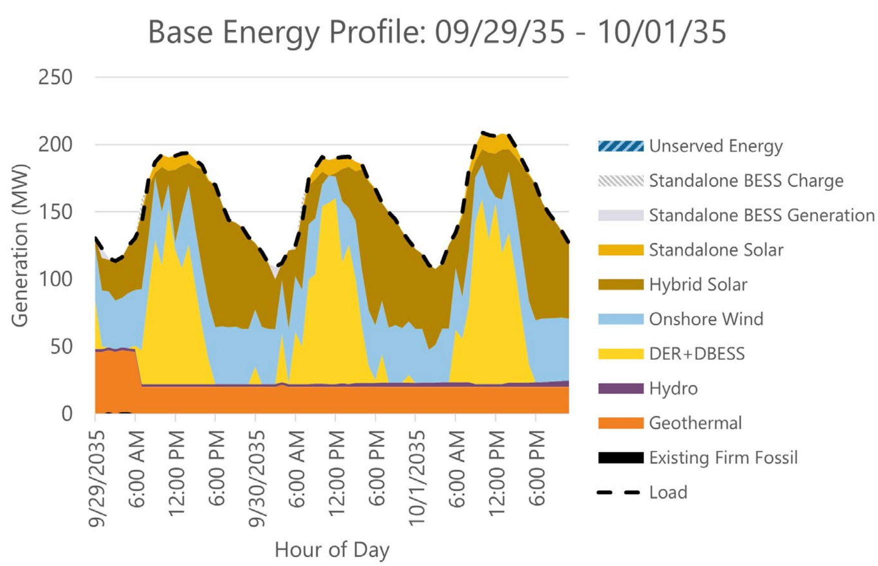


Figure 8-23. Hawai'i Island: detailed Base energy profile, 2035 median load day

8.3.3.3 Operations of Firm Generation

Insights can be gathered into the changing role of firm generation by evaluating the frequency with which different types of firm generators are started and their capacity factor, which is the percentage of hours a generator runs based on its rated capacity. The number of starts and capacity factor, respectively, of the utility-owned thermal generators for the Status Quo and Base resource plans in 2030 and 2035 are shown in Figure 8-24 and Figure 8-25. Because the Status Quo scenario relies more heavily on thermal generators, the generators are started more frequently and operate with a higher capacity factor than in the Base scenario.

Figure 8-24. Hawai'i Island: utility-owned thermal generator number of starts, 2030 and 2035 for Status Quo and Base scenarios

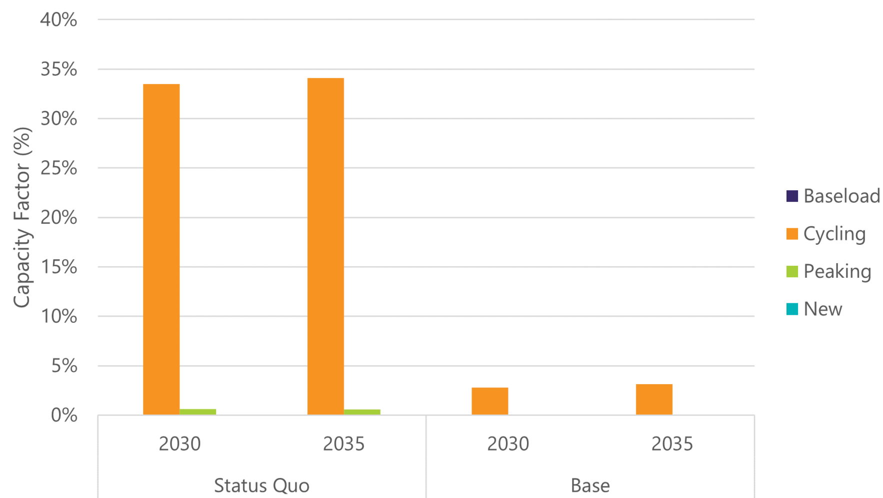


Figure 8-25. Hawai'i Island: thermal generator capacity factor, 2030 and 2035 for Status Quo and Base scenarios

8.3.4 Transmission and System Security Needs

We analyzed Hawai'i Island Base and High electricity demand scenario resource plans to determine transmission and system security needs by performing steady-state analyses and dynamic stability analyses for selected years with major large-scale resource additions, including:

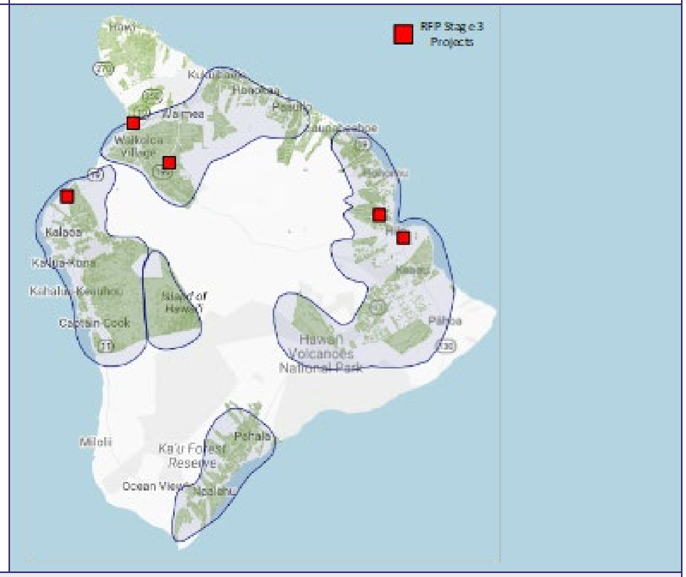
- Hawai'i island system Base scenario resource plan: 2032 and 2050
- Hawai'i island system High Load scenario resource plan: 2032 and 2036

8.3.4.1 Summary of Base Scenario Resource Plan

For the Hawai'i island Base scenario resource plan, the cross-island tie L6200 line and west side L8100/8900 line has risk of overloading condition in both the near term and long term. The cross-island tie L6200 overloading normally happens when there is significant unbalance of generation on the two sides of the island, and because of the contingency, there is a large amount of power flow from the west side of the island toward the east side of the island through a few lines, including the L6200. This overloading can be mitigated by either reconductoring of the L6200 line to 556 AAC or balancing west-side and east-side generation. The overloading of the L8100/8900 line is normally caused by a large flow of power from the east side to the west side of the system when the L6800 line is tripped, especially when there is too much generation interconnected at Keamuku substation.

The steady-state analysis for the Hawai'i Island system also showed that unbalanced generation dispatched between the west side and east side of the island would cause a significant undervoltage issue on either the southern or northern part of the system. This undervoltage issue will become much worse when no generation resource is interconnected in south Hawai'i. It is recommended that the Hawai'i Island system have a resource (capable of providing voltage support) in south Hawai'i.

The following tables summarize the study results for the Base scenario resource plan.

Summary	
Studied resource plan	Studied year
Base scenario resource plan	2032
By 2030, the Hawai'i system will have new generation from Stage 3 procurement and REZ development, which includes 48 MW wind generation of REZ development by 2029 and 140 MW Stage 3 procurement of hybrid solar generation by 2030, interconnecting at the Hawai'i island 69 kV system. It is also assumed that three firm generation plants will be removed by 2031: the 34 MW Hill 5 and 6 will be removed by 2027, the 21 MW Tawhiri wind generation PPA is assumed to expire by 2028, and the 58 MW Hamakua Energy Partners is assumed to expire by the end of 2030. The system peak load is forecasted to reach 214 MW by 2032.	

System Resource Summary and Forecasted Demand (MW)

Fossil fuel–based generation	Onshore standalone wind	Geothermal generation	Large-scale hybrid solar	Hydro	DER	System peak load
85.8	58.5	46	200	16.6	171	214

REZ Enablement

Interconnection sites for the 140 MW Stage 3 projects and 48 MW onshore wind generation are as follows:

Keamuku substation: 30 MW, Puueo substation: 30 MW, Kanoelehua substation: 30 MW, Ouli substation: 20 MW, Poopoomino substation: 30 MW

The interconnection of 48 MW wind generation from REZ development is assumed at the Keamuku substation. The estimated REZ enablement cost for the 48 MW onshore wind interconnection at the Keamuku substation is $37.8 million.

Grid Needs: Transmission System Networks Expansion

None

L6200 overloading observed in the study because of maximum west generation dispatches in which the 214 MW system load is solely supplied by generation from the west side of the island. The solution for deferring the L6200 reconductor is to maintain the minimum generation dispatch requirement on the east side of the system. The minimum MW generation dispatched from the east side of the system is calculated by the following equation:

East side minimum generation (MW) = $\frac{System\ total\ load - 174}{214 - 174} \cdot 20$

If the system total load is lower than 174 MW, there is no mimimum MW requirement of generation dispatched on the east side of the system.

Dependent on the system total load and the east-side generation resources chosen to meet this minimum requirement, the east side may require 20 MVAR of additional reactive power capability to resolve potential north/east voltage violations. At the peak load with 20 MW generation on the east side of the island, the following options are viable for mitigating north/east undervoltage violations:

All 3 units of PGV online.

Puna CT3 online with 2.8 MVAR additional reactive capability required at Kanoelehua or Puueo substations.

Stage 3 Kanoelehua with 20 MVAR additional reactive capability required at Kanoelehua.

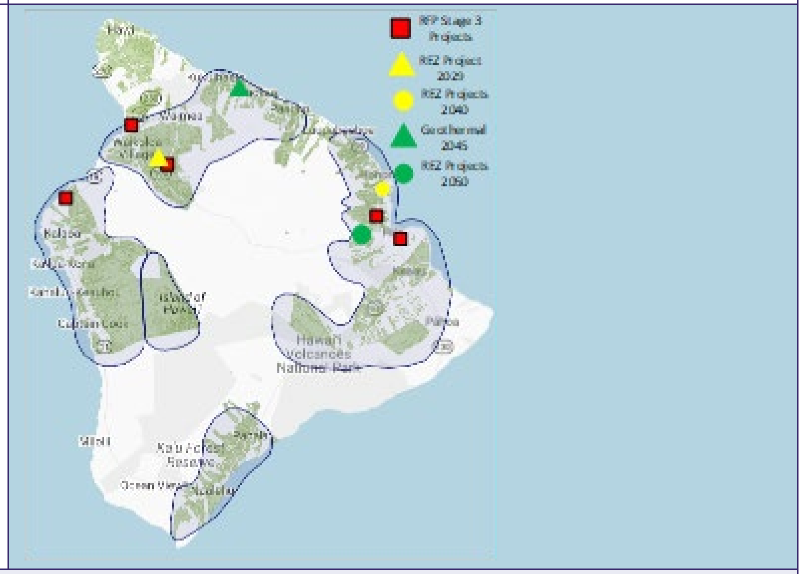
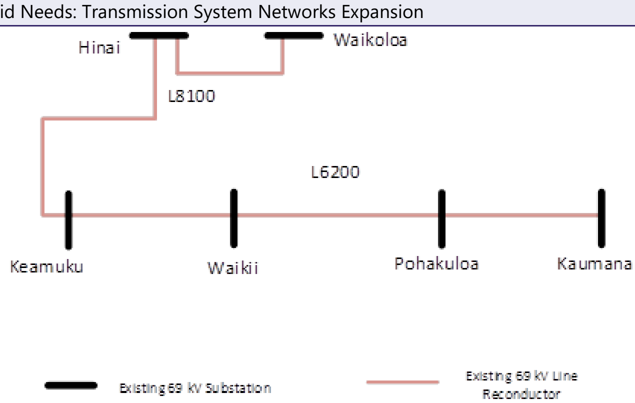
Stage 3 Kanoelehua and Puueo (split output) with 20 MVAR additional reactive capability required between the two locations. The additional reactive capability at Kanoelehua and Puueo are in addition to the assumed capability of the Stage 3 resources at that location.

To mitigate a high loading condition of L8900/8100, it is recommended to move generation interconnection from Keamuku and the east toward the further west side system (e.g., Keahole substation) when the system total load reaches above 200 MW.

To mitigate undervoltage violation identifed on the south side of the system, it is recommended to have a resource interconnected at Keauhou substation with at least 10.4 MVAR capability or at Kamaoa substation with 13.7 MVAR or 13.3 MW capability. The reactive power capability can be replaced by active power capability, or the combination of reactive power and active power capability.

Grid Needs: System Stability Needs

After adding 140 MW Stage 3 hybrid solar projects with grid-forming battery energy storage component, it is expected that Hawai'i Island system stability performance will stay within planning criteria, and no additional system stability needs were identified. When Puna Geothermal Venture units are online, at minimum, a total of 60 MW grid-forming hybrid solar project is required. A 30 MW grid-forming hybrid solar project is required on both east and west sides of the Hawai'i Island system, while maintaining grid-forming resource headroom as 24% of DER generation. When Puna Geothermal Venture units are offline, at minimum, a total of 110 MW grid-forming resource is required. The east side of the system will need 50 MW grid-forming resource online and the west side of the system will need 60 MW grid-forming resource online, while together maintaining grid-forming resource headroom as 61% of DER generation.

<table>
<tr><th colspan="7">Summary</th></tr>
<tr><td colspan="3">Studied resource plan</td><td colspan="4">Studied year</td></tr>
<tr><td colspan="3">Base scenario resource plan</td><td colspan="4">2050</td></tr>
<tr><td colspan="3">In addition to previous system resource changes by 2031, by 2035, the Hawai‘i Island system will have 2 MW standalone battery energy storage and 3 MW hybrid solar from the REZ development. It is assumed that both interconnections will be in distribution circuits by considering their MW size. In 2040, there will be another 20 MW hybrid solar generation developed from the renewable energy zone. In 2045, all fossil fuel–based generation will have fuel switch to biodiesel. In the same year, there will be 30 MW geothermal generation and 2 MW standalone battery energy storage interconnected to the system. By 2050, an additional 14 MW hybrid solar and 2 MW onshore wind generation will be developed from the renewable energy zone. The system annual peak load is forecasted to reach 295 MW by 2050.</td><td colspan="4">
</td></tr>
<tr><td colspan="7">System Resource Summary and Forecasted Demand (MW)</td></tr>
<tr><td>Fossil fuel–based generation</td><td>Onshore standalone wind</td><td>Geothermal generation</td><td>Large-scale hybrid solar</td><td>Hydro</td><td>DER</td><td>System peak load</td></tr>
<tr><td>85.8</td><td>60.5</td><td>76</td><td>237</td><td>16.6</td><td>271</td><td>295</td></tr>
<tr><td colspan="7">REZ Enablement</td></tr>
<tr><td colspan="7">It is assumed that the geothermal generation in service in 2045 will be interconnected at Haina substation, and the REZ generation will be interconnected at Pepeekeo substation (20 MW) in 2040 and Kaumana substation (17 MW) in 2050.
High-level cost estimate for the 20 MW interconnection REZ enablement at the Pepeekeo substation is $24.5 million, and for the 17 MW interconnection REZ enablement at the Kaumana substation is $27.9 million.</td></tr>
<tr><td colspan="7">Grid Needs: Transmission System Networks Expansion</td></tr>
<tr><td colspan="7">
</td></tr>
<tr><td colspan="6">Network expansion cost estimate</td><td>$100.1 million</td></tr>
<tr><td colspan="7">To mitigate undervoltage violations on the north side of the system, it is recommended to dispatch an east unit (e.g., Puna Geothermal Venture) at 5 MW or higher. To mitigate undervoltage violation on the south and southwest side of the system, it is recommended to have a resource interconnected at Kamaoa with 22.5 MW generation capacity.</td></tr>
<tr><td colspan="7">Grid Needs: System Stability Needs</td></tr>
<tr><td colspan="7">Not studied.</td></tr>
</table>

8.3.5 Distribution Needs

This section discusses distribution needs as they pertain to the grid needs assessment for Hawai'i Island.

8.3.5.1 Hosting Capacity Grid Needs

Of the 137 circuits assessed on Hawai'i Island, most have sufficient DER hosting capacity or could accommodate the 5-year hosting capacity without infrastructure investments. The remaining circuits where infrastructure investments are required to increase hosting capacity to accommodate the forecasted distributed energy resources are identified as requiring grid needs. Infrastructure investments or distribution upgrades (i.e., wires solutions) to mitigate the grid needs are identified with cost estimates. The grid needs and solutions are summarized in Table 8-19.

Table 8-19. Hawai'i Island Hosting Capacity Grid Needs (Years 2021–2025)

Parameter (Nominal $)	Base DER Forecast	High DER Forecast	Low DER Forecast
Number of grid needs	2	2	2
Cost summary (wires solutions)	$630,000	$630,000	$630,000

A complete list of the hosting capacity grid needs can be found in the *Distribution DER Hosting Capacity Grid Needs* report.

8.3.5.2 Location-Based Grid Needs

Of the 148 circuits and 82 substation transformers assessed on Hawai'i Island, most have sufficient capacity to accommodate the forecasted load demand. For substation transformers and circuits where there is insufficient capacity, a grid need is identified. Infrastructure investments or distribution upgrades (i.e., wires solutions) to mitigate the grid needs are identified with cost estimates. The grid needs and solutions are summarized in Table 8-20.

Table 8-20. Hawai'i Island Location-Based Grid Needs (Years 2023–2030)

Parameter (Nominal $)	Scenario 1 (Base)	Scenario 2 (High Load)	Scenario 3 (Low Load)	Scenario 4 (Faster Technology Adoption)
Number of grid needs	3	3	3	4
Cost summary (wires solutions)	$2,680,000	$2,680,000	$2,680,000	$3,153,000

A complete list of the load-driven grid needs can be found in Appendix E.

8.3.5.3 Distribution Grid Needs Summary

The minimum number of grid needs identified (i.e., minimum wires solutions) by scenario by island is shown in Table 8-21. This includes both hosting capacity and location-based grid needs.

Table 8-21. Hawai'i Island Minimum Grid Needs Solutions Identified (Years 2023–2030)

Island (Nominal $)	Scenario 1 (Base)	Scenario 2 (High Load)	Scenario 3 (Low Load)	Scenario 4 (Faster Technology Adoption)
Number of grid needs	5	5	5	6
Cost summary (wires solutions)	$3,310,000	$3,310,000	$3,310,000	$3,783,000

8.3.5.4 NWA Opportunities

No NWA opportunities were identified for Hawai'i Island in the Base, High electricity demand, and Low electricity demand scenarios. Results for the Faster Technology Adoption scenario are shown in Table 8-22.

Faster Technology Adoption Scenario

Table 8-22. NWA Opportunity Projects by Track: Faster Technology Adoption Bookend

Track	Operating Date	Transformer	Circuit	Description	Cost (Nominal $)
3 (non-qualified)	2030	Waikoloa	N/A	New circuit and tie	$473,000

8.3.6 Preferred Plan

The capacity expansion modeling conducted in RESOLVE was the starting point for identifying grid needs and developing a resource plan.

Probabilistic resource adequacy analyses were then performed to confirm that the portfolio of resources selected in the resource plan were reliable. In parallel, transmission and system security needs were identified. Based on the results of this analysis, the following changes were made:

- 2030: 24% grid-forming headroom capacity with Puna Geothermal Venture online or 61% grid-forming headroom capacity without Puna Geothermal Venture online for dynamic stability
- 2032: minimum east-side generation that scales with system load
  - For the purposes of this analysis, geothermal resources added by RESOLVE and Stage 3 hybrid solar are considered east-side resources.

Additional capital costs were identified to interconnect resources in the renewable energy zones selected in RESOLVE. While the REZ enablement costs were already included as part of the RESOLVE modeling, they are listed here in Table 8-23 for completeness alongside new network expansion costs.

The Status Quo scenario transmission network expansion costs reflect estimated transmission needed to expand capacity, as identified in the transmission needs analysis, to serve load growth because of electrification of transportation.

Table 8-23. Hawai'i Island Transmission Capital Costs

Nominal Transmission Costs ($MM)	Base		Status Quo	
Years	REZ Enablement	Network Expansion	REZ Enablement	Network Expansion
2029	$45	-	-	-
2031	-	-	-	$96
2035	$3	-	-	-
2040	$24	-	-	-
2050	$26	-	-	-

Table 8-24 shows a comparison of the Hawai'i Island Base production costs with and without transmission constraints.

Comparing the production costs with and without the transmission constraints identified above shows that the dynamic stability and minimum east-side generation requirements do not significantly change production costs, and reduced capital cost of transmission upgrades.

Table 8-24. Comparison of Hawai'i Island Base Scenario Production Costs with and without Transmission Constraints

NPV ($MM)	With Transmission Constraints	Without Transmission Constraints
(2023–2050)	$2,122	$2,122

8.4 Maui

This section describes the results of the grid needs assessment for Maui through the multistep process that includes modeling capacity expansion, resource adequacy, operations of the system, transmission and system security needs, distribution needs, and iterations or adjustments made to determine the preferred plan.

8.4.1 Capacity Expansion Scenarios

In the Base scenario shown in Figure 8-26, onshore wind is selected, primarily because of its low cost, achieving 95% renewable energy by 2030 shown in Figure 8-27. As electricity demand increases hybrid solar is added in the later years. In scenarios with Faster Technology Adoption, High electricity demand and Low electricity demand shown in Figure 8-26, similar resources are selected; however, their amounts change with the magnitude of forecasted load. In the High electricity demand scenario renewable firm resources are added in 2035 and increases in magnitude following the load forecast as the years progress. Existing fossil fuel–based resources are shown as firm renewable resources in 2050 because of their switch to biofuels in 2045.

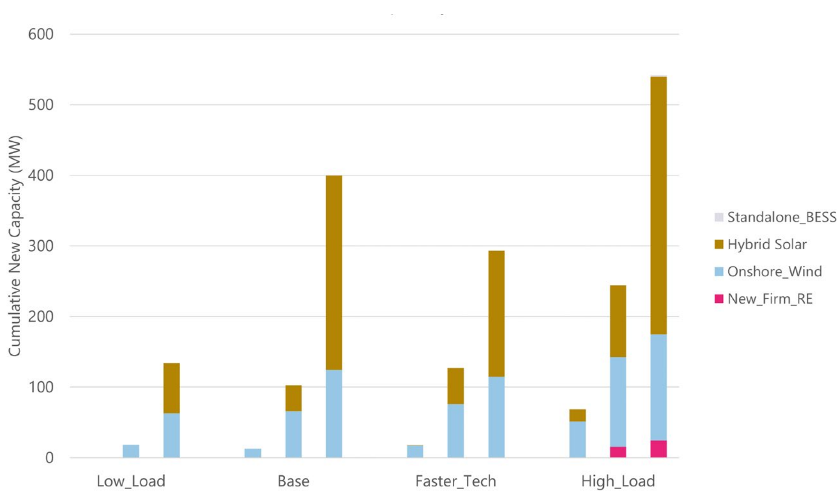


Figure 8-26. Maui: cumulative new capacity selected by RESOLVE in 2030, 2035, and 2050 for the Base, Low Load, High Load, and Faster Technology Adoption scenarios

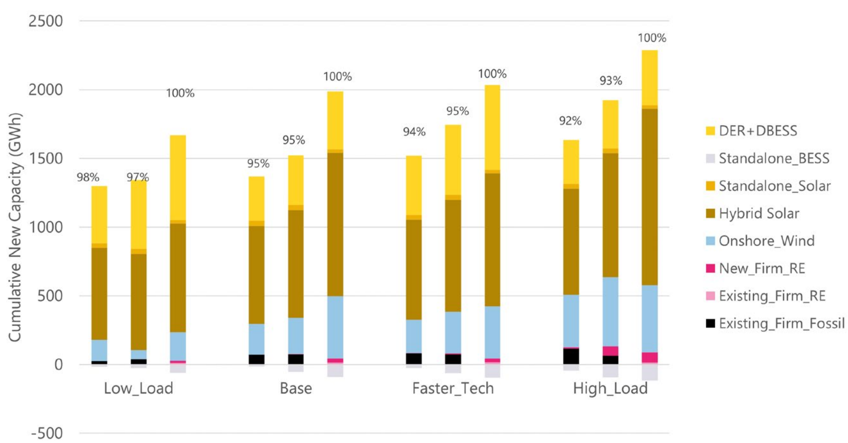


Figure 8-27. Maui: annual generation and RPS from resources in 2030, 2035, and 2050 for the Base, Low Load, High Load, and Faster Technology Adoption scenarios

8.4.1.1 High Fuel Retirement Optimization Scenario

In addition to the planned retirements of Mā'alaea 1–13 and Kahului 1–4, the High Fuel Retirement Optimization scenario chooses to retire 54 MW of firm generation capacity shown in Figure 8-28. All additional retirements occur early in the planning horizon before and in 2030.

Because the model front-loads the removal of units early in the planning horizon, extreme care must be taken to ensure that customers are not adversely affected by an inadequate system. Additionally, this scenario accelerates the buildout of hybrid solar and adds new firm generating resources compared to the Base scenario. In practice, to ensure that sufficient replacement resources are in service to facilitate the retirements selected in this sensitivity, the unit removals would need to be staggered similar to our proposed removal-from-service schedule. Otherwise, the retirements shown in this sensitivity would increase the risk of unserved energy to our customers. The retirements shown in this sensitivity comprise partial unit retirements because of the linear optimization aspect of the model.

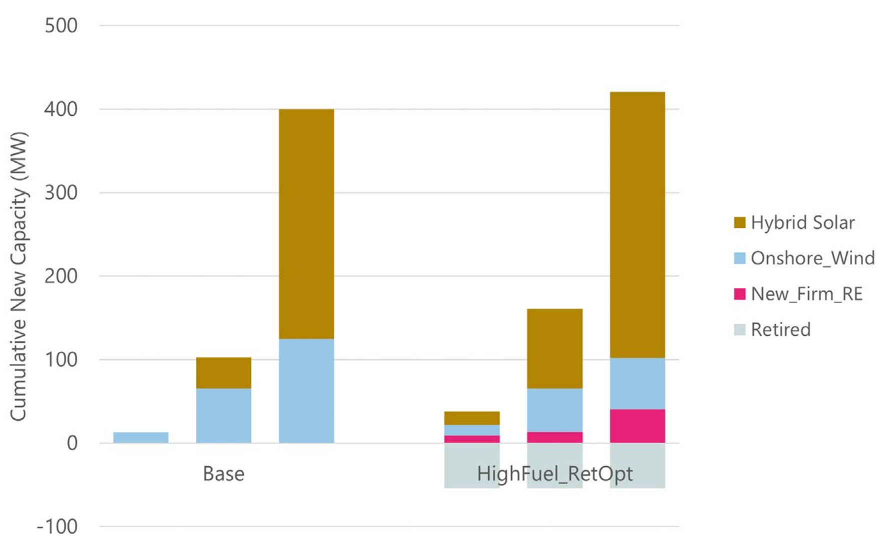


Figure 8-28. Maui: cumulative new capacity selected by RESOLVE in 2030, 2035, and 2050 for the Base and High Fuel Retirement Optimization scenarios

Shown in Figure 8-29, the expected renewable energy achievement does not significantly increase under the high fuel price sensitivity (95% compared to 96% in 2030).

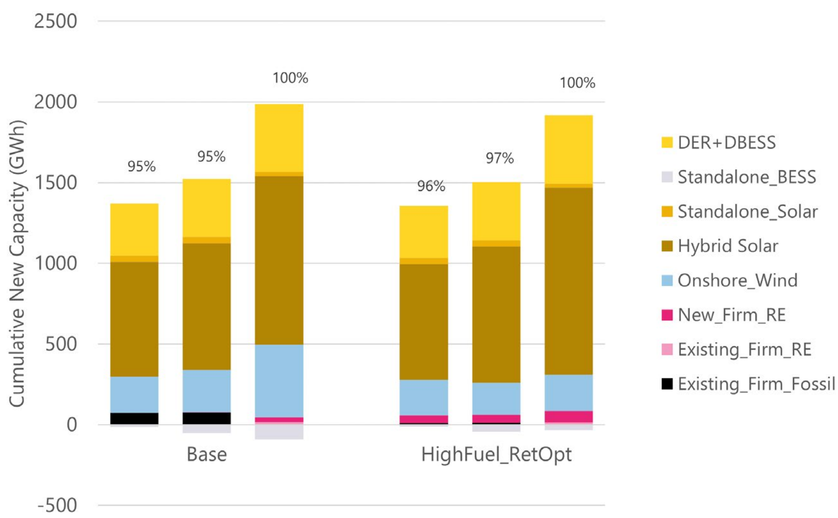


Figure 8-29. Maui: annual generation and RPS from resources in 2030, 2035, and 2050 for the Base and High Fuel scenarios

8.4.2 Resource Adequacy

On Maui, several key decision points are illustrated by the probabilistic resource adequacy analyses. By 2030, we plan for the removal of 122 MW of existing fossil-fuel firm generation. The impact of this planned removal is mitigated by the addition of new resources through the Stage 3 procurement. However, if we acquire less than the full Stage 3 targeted need, additional resources may need to be acquired through additional procurements.

For Maui, Kahului 1–4 and Māʻalaea 10–13 are assumed to be retired by 2027 to comply with regional haze rules and Māʻalaea 1–9 are assumed to be retired by 2030, as shown in Table 8-25. This is largely due to the lack of replacement parts for maintenance.

Table 8-25. Generating Unit Deactivation/Retirement Assumptions

Year	Generating Unit
2027	Kahului 1–2 removed from service (9.47 MW) Kahului 3–4 removed from service (23 MW) Māʻalaea 10–13 removed from service (49.36 MW)
2030	Māʻalaea 1–3 removed from service (7.5 MW) Māʻalaea 4–9 removed from service (33 MW)

If development of future large-scale renewables reaches the target presented in the Base scenario:

- We expect loss of load of less than 0.1 day per year, assuming planned deactivations through 2030 and the full targeted need for the Stage 3 procurement is acquired (40 MW of new firm generation and 191 MW of new hybrid solar or wind by 2027).
- We expect loss of load of less than 0.1 day per year even if we acquire less than the full target for Stage 3 (40 MW of new firm generation and 191 MW of new hybrid solar or wind by 2027). If we fulfill the firm renewable target but the variable renewable target is not, we expect a loss of load of less than 0.1 day per year. If we fulfill the variable renewable target, between 9 and 18 MW of new firm renewables are needed to achieve a loss of load expectation less than 0.1 day per year.

By 2035, we do not assume any additional thermal unit deactivations or retirements. The Stage 3 acquired resources are still needed to maintain reliability.

- We expect loss of load of less than 0.1 day per year, assuming planned deactivations through 2030 and we acquire the full target sought in Stage 3 procurement (40 MW of new firm generation and 191 MW of new variable renewable generation paired with storage by 2027).

Probabilistic Resource Adequacy Summary

Table 8-26 shows the 2030 Resource Adequacy results for the Base resource plans that were produced by RESOLVE. The results show that, in 2030, the resource plan developed by RESOLVE should meet our reliability target.

Table 8-26. Probabilistic Analysis: Results Summary, Maui Island, 2030

Scenario	Existing Firm	New Firm	Stage 3 RFP	Future Wind	Future Hybrid Solar	Future Standalone BESS	LOLE	LOLEv	LOLH	EUE (GWh)	EUE (%)
Base	119	36	191	13	0	0	0.00	0.01	0.02	0.0001	0.00

Table 8-27 shows the 2035 Resource Adequacy results for the Base resource plan with the Base Load and High Load forecast. The results show that, in 2035, the Base resource plan meets the loss of load expectation target but with a high load forecast, the Base plan does not meet the loss of load expectation target.

Table 8-27. Probabilistic Analysis: Results Summary, Maui Island, 2035

Scenario	Existing Firm	New Firm	Stage 3 RFP	Future Wind	Future Hybrid Solar	Future Standalone BESS	LOLE	LOLEv	LOLH	EUE (MWh)	EUE (%)
Base Load	119	41	191	24	37	0	0.013	0.10	0.24	0.00	0.000
High Load	119	41	191	24	37	0	3.58	7.08	14.79	0.32	0.030

In 2035, assuming a High electricity demand scenario and all of Stage 3 RFP (191 MW of hybrid solar and 40 MW of renewable firm) and 37 MW of hybrid solar from the RESOLVE model:

- Approximately 540 MW of additional hybrid solar is needed to bring the system loss of load expectation down below 0.1 day per year.
- Approximately 33 MW of additional firm generation is needed to bring the system loss of load expectation down below 0.1 day per year.

See Section 12 for more details on risks of the resource portfolio given uncertainties in procuring and acquiring the optimal mix of resources.

8.4.3 Grid Operations

The transition to 100% renewables will necessitate a change in how the thermal generators on our system operate. Scenarios with more renewable resources will use thermal generators less often. This is shown in the daily energy profiles and operational statistics in this section.

8.4.3.1 Status Quo Typical Operations

For the Maui Island Status Quo scenario, Māʻalaea 1–9 are assumed to remain in service and Kaheawa Wind Power 1, Kaheawa Wind Power 2, and Auwahi Wind are assumed to have their contracts continued for the study period.

The energy profiles shown in Figure 8-30 and Figure 8-31 show the median load day in 2030 and 2035 of the Status Quo scenario as well as the day directly preceding and following the median load day. This shows how the resource portfolio is meeting the system load over a typical few days during a given year.

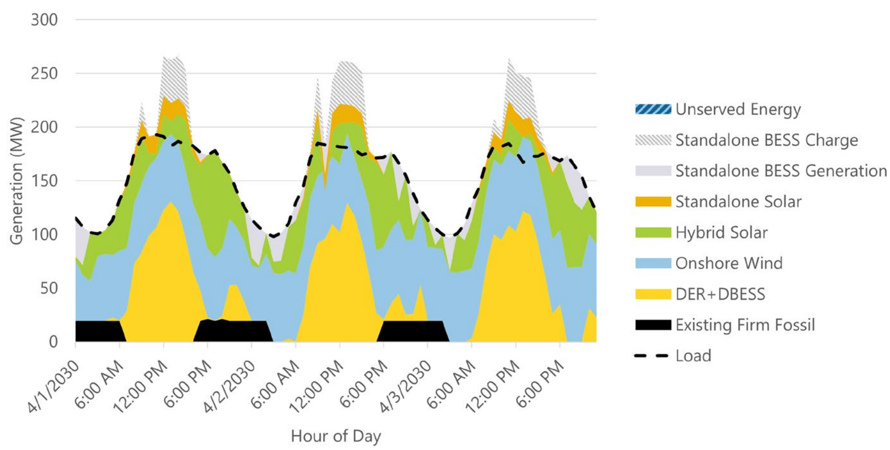


Figure 8-30. Maui: detailed Status Quo energy profile, 2030 median load day (April 1–3, 2030)

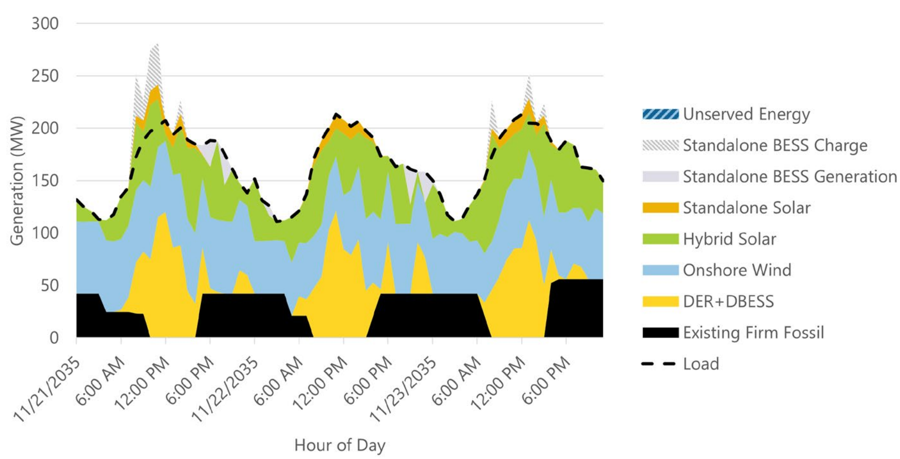


Figure 8-31. Maui: detailed Status Quo energy profile, 2035 median load day (November 21–23, 2035)

8.4.3.2 Base Scenario Typical Operations

The dispatch of the resources in the Base resource plan in 2030 and 2035, respectively, for a few days with average load is shown in Figure 8-32 and Figure 8-33. In the Base scenario, during midday, most of the load is expected to be met from variable renewable resources. In 2030 and 2035 the system is effectively operating on 100% renewable energy.

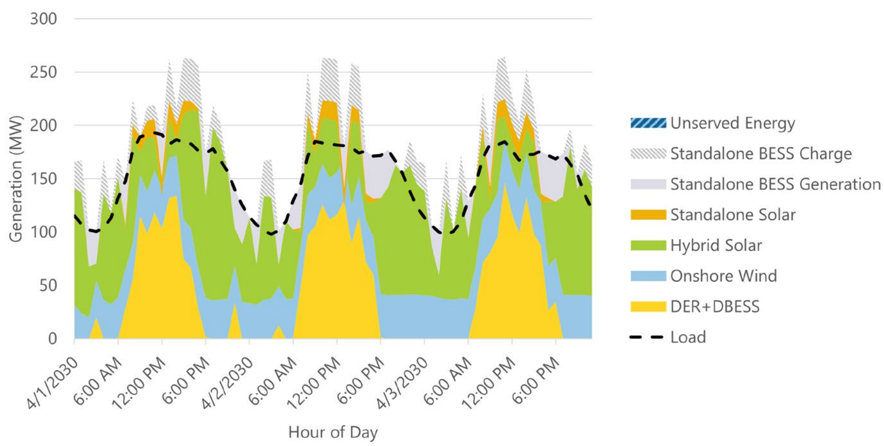


Figure 8-32. Maui: detailed Base scenario energy profile, 2030 median load day

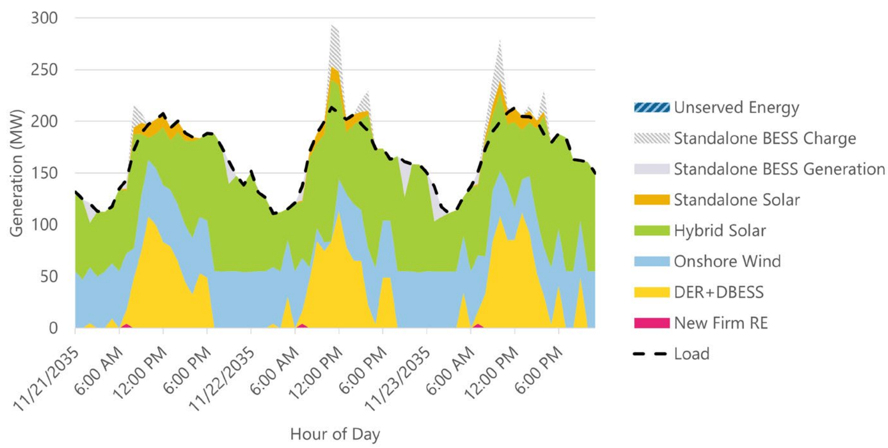


Figure 8-33. Maui: detailed Base scenario energy profile, 2035 median load day

8.4.3.3 Operations of Firm Generation

We can gather insights into the changing role of firm generation by evaluating the number of starts of different types of firm generators and the amount those generators run, or the capacity factor, which is the percentage of hours a generator runs based on its rated capacity. The number of starts and capacity factor, respectively, of the utility-owned thermal generators for the Status Quo and Base resource plans in 2030 and 2035 are shown in Figure 8-34 and Figure 8-35. Because the Status Quo scenario relies more heavily on older thermal cycling generators, the generators are started less frequently and operate with a higher capacity factor than in the Base scenario in 2030. Because the Base scenario has newer internal-combustion units, there are more unit starts initially and decrease as more hybrid solar is added to the system.

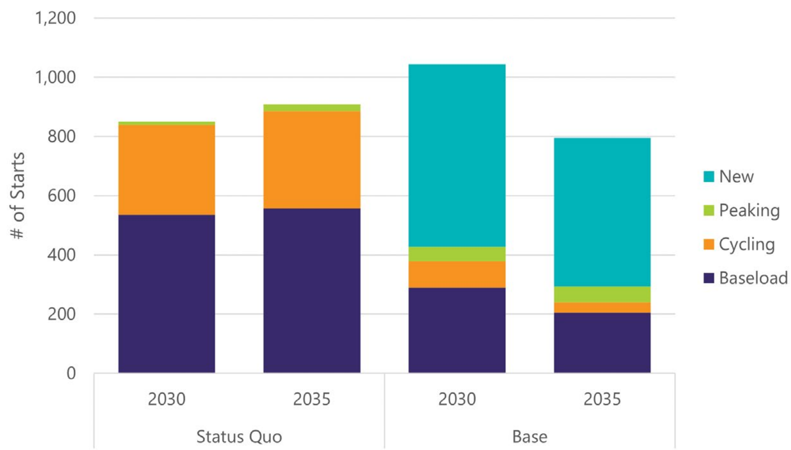


Figure 8-34. Maui: thermal generators number of starts, 2030 and 2035 for Status Quo and Base scenario

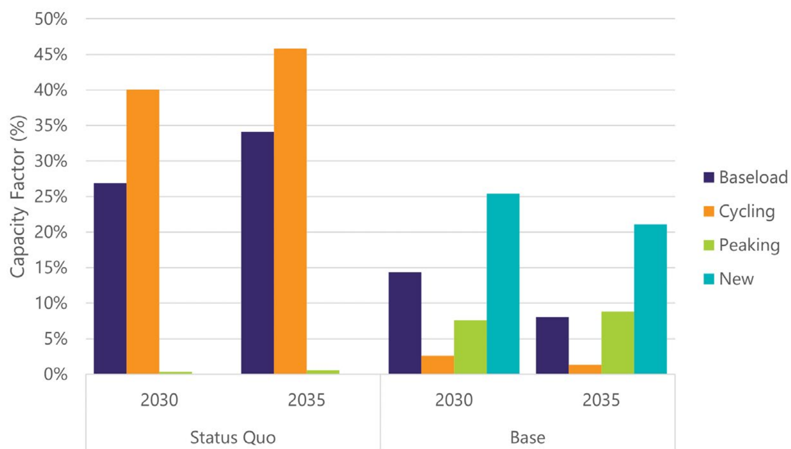


Figure 8-35. Maui: thermal generators capacity factor, 2030 and 2035 for Status Quo and Base scenario

8.4.4 Transmission and System Security Needs

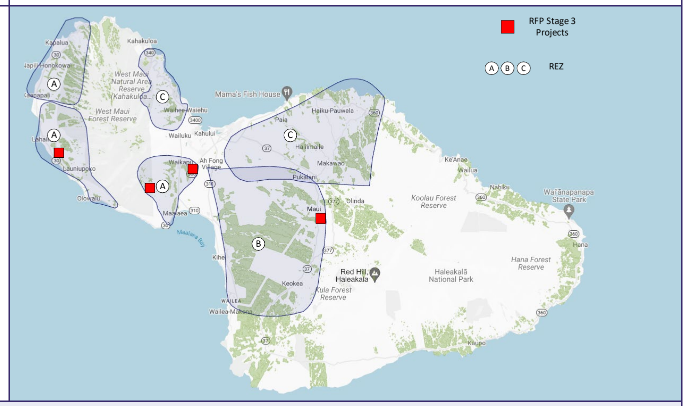
We analyzed the Maui Base and High electricity demand scenario resource plans to determine transmission and system security needs by performing steady-state analyses and dynamic stability analyses for selected years with major large-scale resource additions, including:

- Maui system Base scenario resource plan: 2027, 2035, 2041, 2045, and 2050
- Maui system High load scenario resource plan: 2027, 2030, and 2035

8.4.4.1 Summary of Maui Base Scenario Resource Plan

In the Maui Base scenario resource plan, signficant large-scale resources will be interconnected to the system, requiring transmission network expansion for REZ development and forecasted load increases from electrification.

The large-scale resources in the Base plan provide the system with sufficient grid-forming resources and maintain system stability within the Maui trasmission planning criteria. The following tables summarize the study results for the Maui Base scenario resource plan.

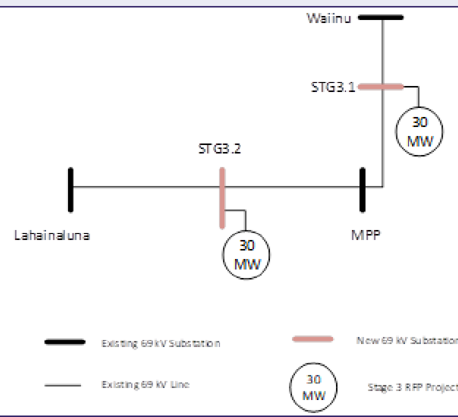
Summary	
Studied resource plan	Studied year
Base scenario resource plan	2027
By 2027, the Maui system will have new generation, which includes 171 MW renewable dispatchable generation and 36 MW firm generation, interconnected at the Maui 69 kV system. Meanwhile, the Maui system will finish Waena switchyard construction, Kahului Power Plant retirement and conversion of units 3 and 4 to synchronous condensers, and retirement of Māʻalaea Power Plant units 10–13. The system peak load is forecasted to reach 207 MW by 2028.	

System Resource Summary and Forecasted Demand (MW)					
Firm generation	Onshore standalone wind	Large-scale hybrid solar	Standalone BESS	DER	System peak load
197.5	42	296	40	170.7	207

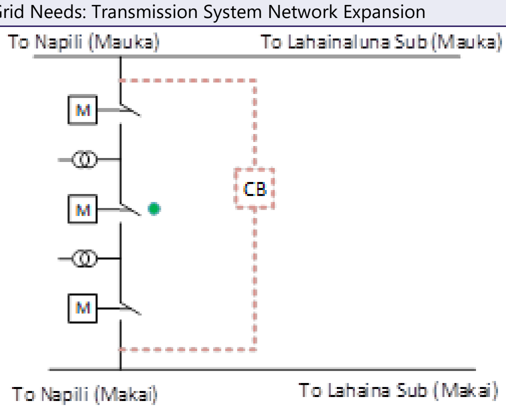
REZ Enablement

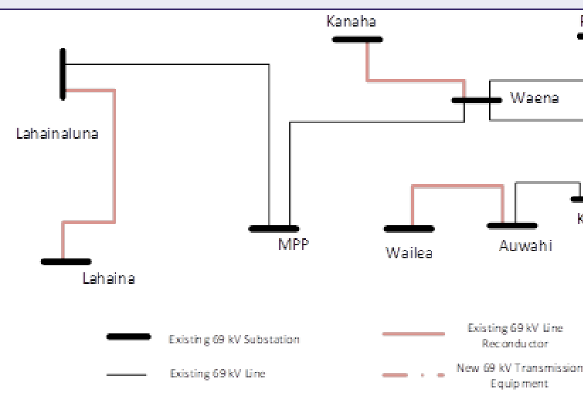
No REZ enablement cost estimate because by 2027 existing locations are proposed to be used for Stage 3. Interconnection sites for the 171 MW Stage 3 projects and 36 MW firm generation are as follows:

Substation/switching station interconnections:
Lahainaluna substation station: 60 MW,
KWP 2 substation: 30 MW
Waena switch yard: 40 MW firm generation
Kealahou substation: 21 MW
69 kV transmisison line interconnection:
MPP: Waiinu line interconnection—30 MW, through a new substation STG3.1
MPP: Lahainaluna line interconnection—30 MW, through a new substation STG3.2



Grid Needs: Transmission System Network Expansion



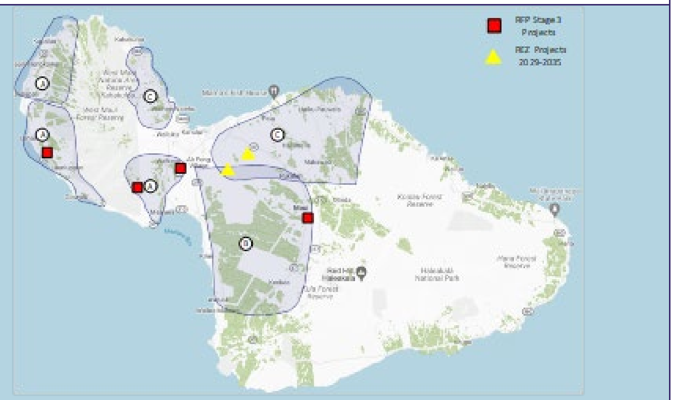


Network Cost Estimate	$10.5 million

Alternative options for above reconductor upgrade include reducing grid-scale resource interconnection MW size by 24 MW on west Maui and reducing grid-scale resource interconnection MW size in Waena switchyard, up-country or south Maui by 16 MW.

Grid Needs: System Stability Needs

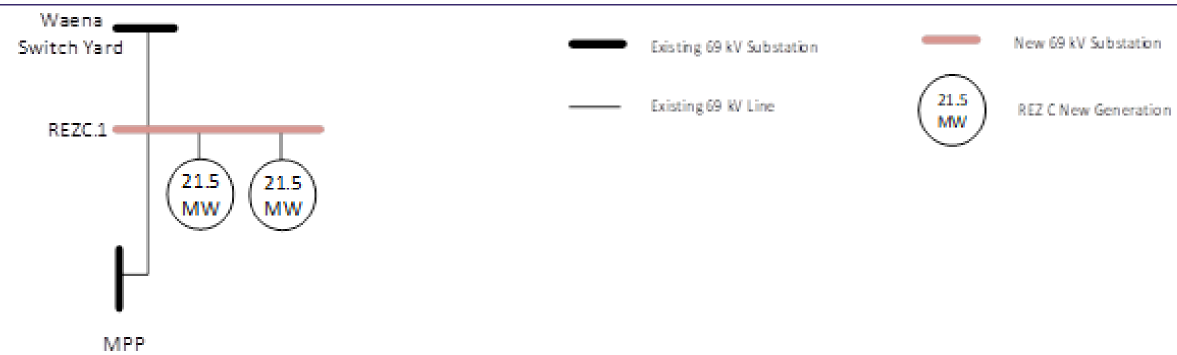
After adding 171 MW Stage 3 RDG projects with grid-forming BESS component, it is expected that Maui system stability performance will stay within planning criteria, and no additional grid needs regarding system stability are identified. Maui system single point of failure limit can be increased to 30 MW as well.

Summary	
Studied resource plan	Studied year
Base scenario resource plan	2035
In addition to previous system resource changes by 2027, by 2035, the Maui system will have 66 MW large-scale onshore wind generation, 37 MW hybrid solar generation interconnected at Maui transmission system. This new generation will be developed in renewable energy zone C. Also, it is planned that the Māʻalaea Power Plant units 1–9 will be removed by 2030, and assumed wind power generation Kaheawa Wind Power 2 and Auwahi will be retired by 2033. The system annual peak load is forecasted to reach 235 MW by 2036.	

System Resource Summary and Forecasted Demand (MW)					
Firm generation	Onshore standalone wind	Large-scale hybrid solar	Standalone BESS	DER	System peak load
152	66	333	40	202	237

REZ Enablement

From 2028 to 2035, 5 MW onshore wind genration in 2029, 8 MW onshore wind generation in 2030, 53 MW onshore wind in 2035, and 37 MW hybrid solar, connected to renewable energy zone C, totaling 103 MW. It is assumed that there will be a new switching station in renewable energy zone C.1 on the MPP-Waena line that will host 43 MW out of 103 MW generation, and the remaining 60 MW will be hosted in the Waena switchyard. The cost of REZ enablement for the 60 MW generation interconnection at the Waena switchyard is estimated as $13.5 million. For the new switching station renewable energy zone C.1, the REZ enablement cost is estimated as $5.8 million.

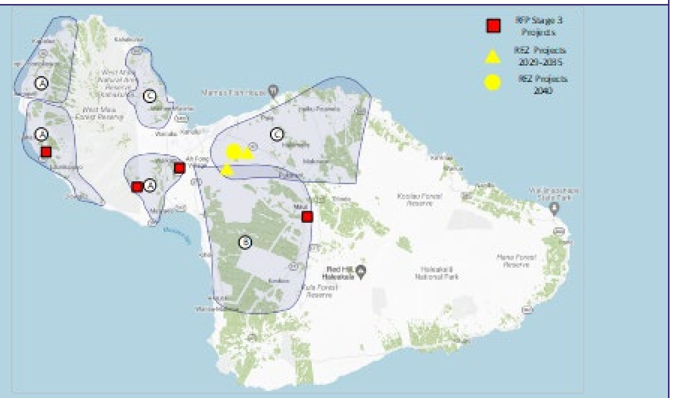
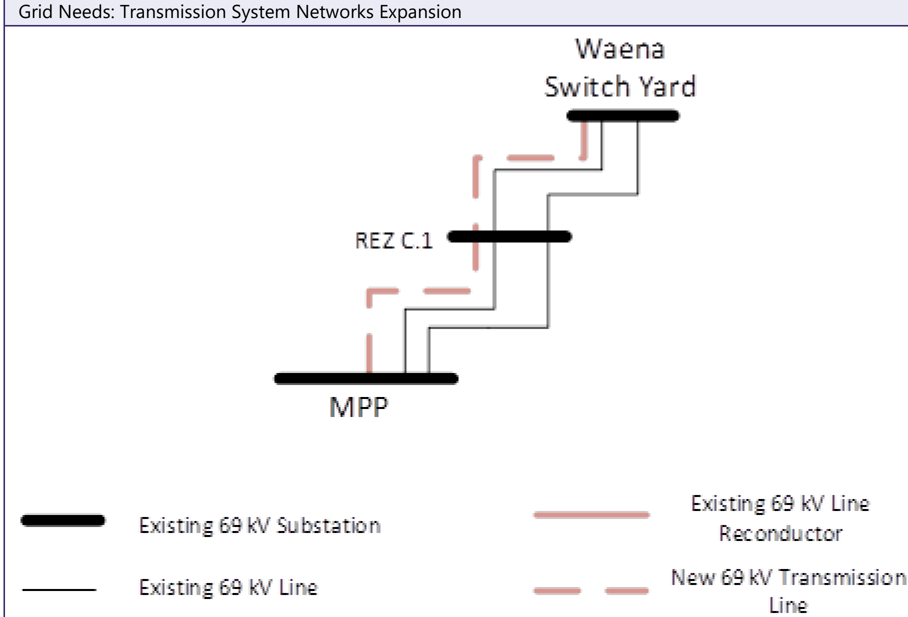


Grid Needs: Transmission System Networks Expansion

Networks expansion cost estimate	$96.2 million

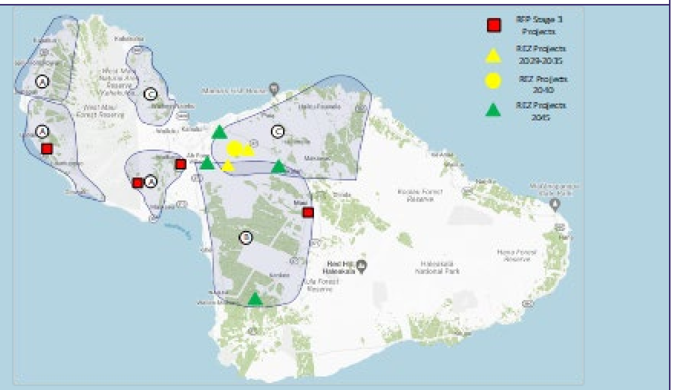
Grid Needs: System Stability Needs

None

Summary					
Studied resource plan			Studied year		
Base scenario resource plan			2040		
In 2040, another 61 MW renewable energy zone C development will be completed. It is assumed that 61 MW will be interconnected at Waena switchyard. Meanwhile, there will be retirement of existing 5.7 MW distribution interconnected solar. System annual peak demand is forecasted to reach 266 MW in 2041.					
System Resource Summary and Forecasted Demand (MW)					
Firm generation	Onshore standalone wind	Large-scale hybrid solar	Standalone BESS	DER	System peak load
152	84	376	40	218	266
REZ Enablement					
The new 61 MW of generation in the renewable energy zone C development is assumed to interconnect at the Waena switchyard, which will require two breakers and a half bay for the generation interconnection. Cost estimate of REZ enablement for 61 MW interconnection is $15.6 million.					
Grid Needs: Transmission System Networks Expansion					
					
Network expansion cost estimate				$51.9 million	
An alternative option for adding a new circuit between Māʻalaea Power Plant and Waena switchyard is to reduce large-scale generation interconnection from the renewable energy zone C development by 48.4 MW.					
Grid Needs: System Stability Needs					
None					

Summary	
Studied resource plan	Studied year
Base scenario resource plan	2045

In 2045, 66 MW hybrid solar generation and 41 MW onshore wind generation will be developed in renewable energy zone C; 15 MW hybrid solar generation will be developed in renewable energy zone B. Also, all the remaining fossil-fuel units will switch to biodiesel. The system annual peak demand is forecasted to reach 289 MW in 2046.



System Resource Summary and Forecasted Demand (MW)					
Firm generation	Onshore standalone wind	Grid-scale hybrid solar	Standalone BESS	DER	System peak load
152	125	457	40	229	289

REZ Enablement

According to the resource plan, 15 MW generation from renewable energy zone B and 107 MW generation from renewable energy zone C will be interconnected to the Maui system. In the study, the following interconnection sites are assumed:

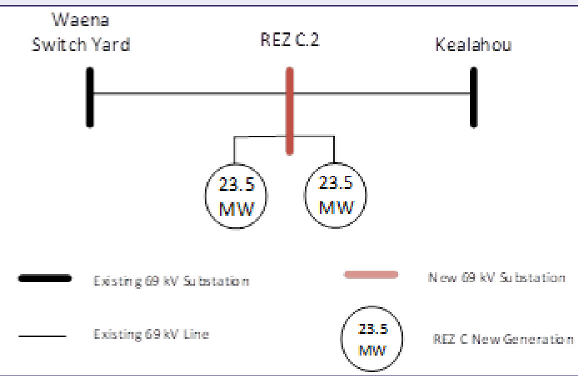
Auwahi substation: 15 MW

STG3.1: 30 MW

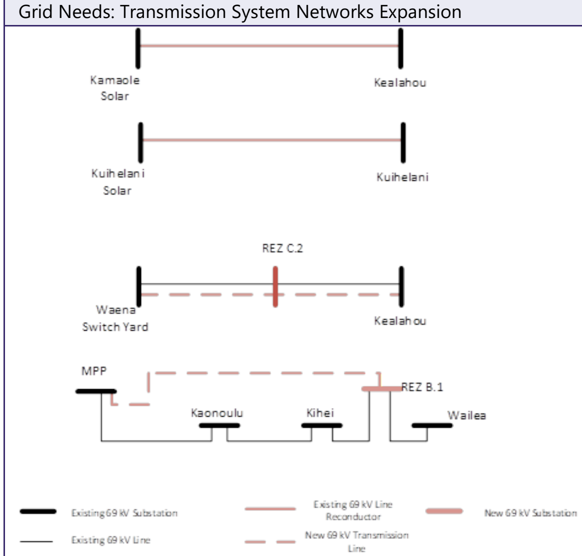
Kanaha substation (23 kV): 30 MW

New switching station, zone C.2, on Waena-Kealahou line: 47 MW

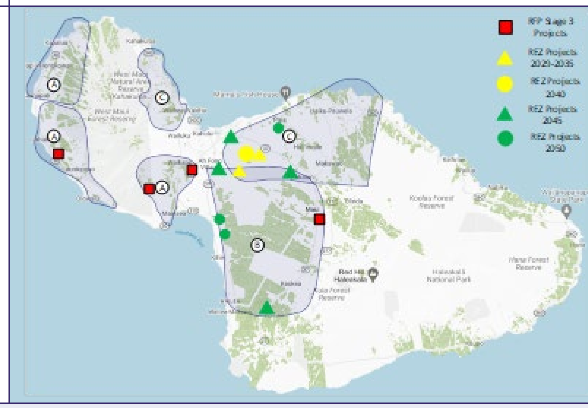
The cost estimate of the REZ enablement for the 30 MW interconnection at the STG 3.1 substation is $3.9 million, for the 30 MW interconnection at the Kanaha substation 23 kV side is $3.8 million, and for the 47 MW interconnection at the new substation renewable energy zone C.2 is $7.8 million. The total estimate for the REZ enablement is $15.4 million.

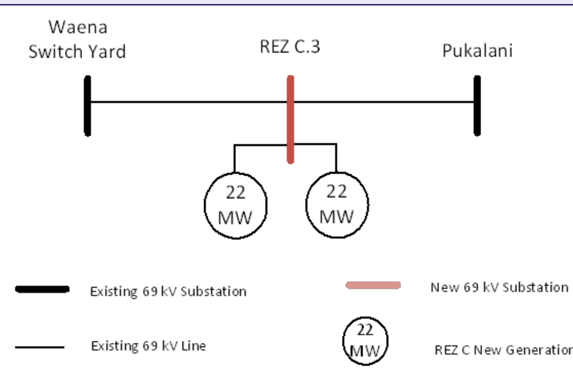
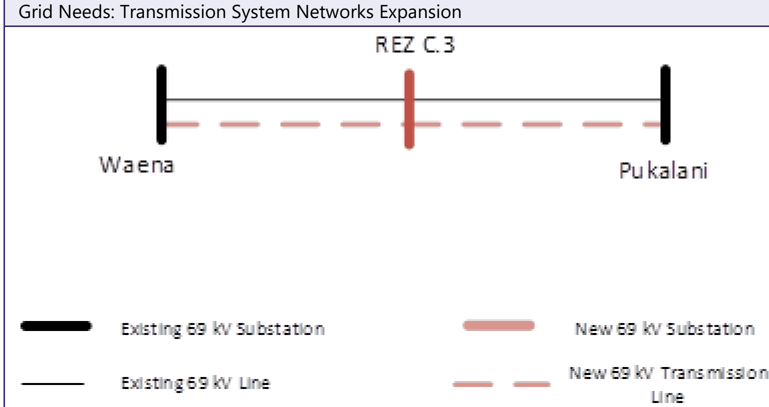


Grid Needs: Transmission System Networks Expansion



Network expansion cost estimate	$171.2 million
An alternative option for the reconductor of the Kamaole-Kealahou line is to reduce south Maui generation interconnection size by 7 MW.	
Grid Needs: System Stability Needs	
Not studied.	

<table>
<tr><th colspan="6">Summary</th></tr>
<tr><td colspan="3">Studied resource plan</td><td colspan="3">Studied year</td></tr>
<tr><td colspan="3">Base scenario resource plan</td><td colspan="3">2050</td></tr>
<tr><td colspan="3">In 2050, 57 MW hybrid solar generation will be developed in renewable energy zone C; 57 MW hybrid solar generation will be developed in renewable energy zone B. System annual peak demand is forecasted to reach 310 MW in 2050.</td><td colspan="3"></td></tr>
<tr><td colspan="6">System Resource Summary and Forecasted Demand (MW)</td></tr>
<tr><td>Firm generation</td><td>Onshore standalone wind</td><td>Large-scale hybrid solar</td><td>Standalone BESS</td><td>DER</td><td>System peak load</td></tr>
<tr><td>152</td><td>125</td><td>571</td><td>40</td><td>240</td><td>310</td></tr>
<tr><td colspan="6">REZ Enablement</td></tr>
<tr><td colspan="4">In the study, the following interconnection sites are assumed for the 114 MW generation development in renewable energy zones B and C:
Renewable energy zone B.1 Substation: 51 MW
Auwahi Substation: 7 MW
Renewable energy zone C.2 (Waena-Kealahou) Substation: 13 MW
New switching station, renewable energy zone C.3, on Waena-Pukalani line: 44 MW

The estimated cost for REZ enablement in renewable energy zone B.1 substation is $9.0 million and for REZ enablement of building the renewable energy zone C32 is $ 9.0 million. The total REZ enablement estimated cost is $18.0 million. It is assumed in the study that the 7 MW generation interconnection at the Auwahi substation and 13 MW generation interconnection at the renewable energy zone C.2 substation are interconnected without adding a new breaker and a half bay but just expansion of previously developed projects.</td><td colspan="2">
</td></tr>
<tr><td colspan="6">Grid Needs: Transmission System Networks Expansion</td></tr>
<tr><td colspan="6">

Besides above adding a new 69 kV line between Waena switchyard and Pukalani substation, it is also proposed to replace the two 69/23 kV tie transformers at Kanaha substation by two units of larger transformers with a forced-air rating of at least 24 MVA.</td></tr>
<tr><td colspan="5">Network expansion cost, including upgrade of two tie transformers</td><td>$123.1 million</td></tr>
<tr><td colspan="6">An alternative of upgrading two units of the Kanaha tie transformer is to use DER program, or demand response program, or EE program to reduce peak load of the Maui 23 kV network by at least 4 MW.</td></tr>
<tr><td colspan="6">Grid Needs: System Stability Needs</td></tr>
<tr><td colspan="6">Not studied</td></tr>
</table>

8.4.5 Distribution Needs

This section discusses distribution needs as they pertain to the grid needs assessment for Maui.

8.4.5.1 Hosting Capacity Grid Needs

Of the 88 circuits assessed on Maui, most have sufficient DER hosting capacity or could accommodate the 5-year hosting capacity without infrastructure investments. The remaining circuits where infrastructure investments are required to increase hosting capacity to accommodate the forecasted distributed energy resources are identified as requiring grid needs. Infrastructure investments or distribution upgrades (i.e., wires solutions) to mitigate the grid needs are identified with cost estimates. The grid needs and solutions are summarized in Table 8-28.

Table 8-28. Maui Hosting Capacity Grid Needs (Years 2021–2025)

Parameter (Nominal $)	Base DER Forecast	High DER Forecast	Low DER Forecast
Number of grid needs	3	7	3
Cost summary (wires solutions)	$2,500,000	$3,315,000	$2,500,000

A complete list of the hosting capacity grid needs can be found in the *Distribution DER Hosting Capacity Grid Needs* report.

8.4.5.2 Location-Based Grid Needs

Of the 93 circuits and 62 substation transformers assessed on Maui, most have sufficient capacity to accommodate the forecasted load demand. For substation transformers and circuits where there is insufficient capacity, a grid need is identified. Infrastructure investments or distribution upgrades (i.e., wires solutions) to mitigate the grid needs are identified with cost estimates. The grid needs and solutions are summarized in Table 8-29.

Table 8-29. Maui Location-Based Grid Needs (Years 2023–2030)

Parameter (Nominal $)	Scenario 1 (Base)	Scenario 2 (High Load)	Scenario 3 (Low Load)	Scenario 4 (Faster Technology Adoption)
Number of grid needs	1	1	1	1
Cost summary (wires solutions)	$63,000	$63,000	$63,000	$63,000

A complete list of the load-driven grid needs can be found in Appendix E.

8.4.5.3 Distribution Grid Needs Summary

The minimum number of grid needs identified (i.e., minimum wires solutions) by scenario by island is shown in Table 8-30. This includes both hosting capacity and location-based grid needs.

Table 8-30. Maui Minimum Grid Needs Solutions Identified (Years 2023–2030)

Island (Nominal $)	Scenario 1 (Base)	Scenario 2 (High Load)	Scenario 3 (Low Load)	Scenario 4 (Faster Technology Adoption)
Number of grid needs	4	4	8	8
Cost summary (wires solutions)	$2,513,000	$2,513,000	$3,377,000	$3,377,000

8.4.5.4 NWA Opportunities

No NWA opportunities are identified for Maui.

8.4.6 Preferred Plan

The capacity expansion modeling conducted in RESOLVE was the starting point for identifying grid needs and developing a resource plan. Probabilistic resource adequacy analyses were then performed to confirm that the portfolio of resources selected in the resource plan were reliable. Based on the results of this analysis, the following changes were made:

- Modified Stage 3 firm renewable proxy to two 8.14 MW units based on 2030 resource adequacy results
- Increased duration of paired and standalone BESS to 4 hours to match current market conditions
- Updated the Stage 3 RFP variable renewable proxy to reflect the current target, which was adjusted for the withdrawal of Kahana Solar.

In parallel, transmission and system security needs were identified. Based on the results of this analysis, the following changes were made:

- 2027: 60% grid-forming headroom capacity for dynamic stability
- 2045: reduce south Maui generation (Paeahu, Kamaole, Auwahi [rebuilt], renewable energy zone Group B) by 7 MW

Additional capital costs were identified to interconnect resources in the renewable energy zones selected in RESOLVE. While the REZ enablement costs were already included as part of the RESOLVE modeling, they are listed here in Table 8-31 for completeness alongside new network expansion costs.

The Status Quo scenario transmission network expansion costs reflect estimated transmission needed to expand capacity, as identified in the transmission needs analysis, to serve load growth because of electrification of transportation.

Table 8-31. Maui Transmission Capital Costs

Nominal Transmission Costs ($MM)	Base		Status Quo	
Years	REZ Enablement	Network Expansion	REZ Enablement	Network Expansion
2030	$50	$11	-	2
2035	$18	$89	-	22
2040	$14	$47	-	-
2045	$13	$131	-	68
2050	$15	$120	-	13

Table 8-32 presents a comparison of Maui Island Base scenario production costs with and without transmission constraints.

Table 8-32. Comparison of Maui Island Base Scenario Production Costs with and without Transmission Constraints

NPV ($MM)	With Transmission Constraints	Without Transmission Constraints
(2023–2050)	$2,229	$2,233

8.5 Moloka'i

This section describes the results of the grid needs assessment for Moloka'i through the multistep process that includes modeling capacity expansion, resource adequacy, operations of the system, transmission and system security needs, distribution needs, and iterations or adjustments made to determine the preferred plan.

8.5.1 Capacity Expansion Scenarios

The Base scenario, shown in Figure 8-36 and Figure 8-37, selects high levels of hybrid solar, allowing Moloka'i to achieve 87% renewable energy by 2030. In the Base, High electricity demand, Low electricity demand, and Faster Technology Adoption scenarios, the types of resources selected by RESOLVE remain the same (hybrid solar and standalone BESS); only the quantity changes proportional to the growth of electricity demand. Existing fossil fuel–based resources are shown as firm renewable resources in 2050 because of their switch to biofuels in 2045. All scenarios achieve their RPS targets with consistent increases in utilization of renewable resources.

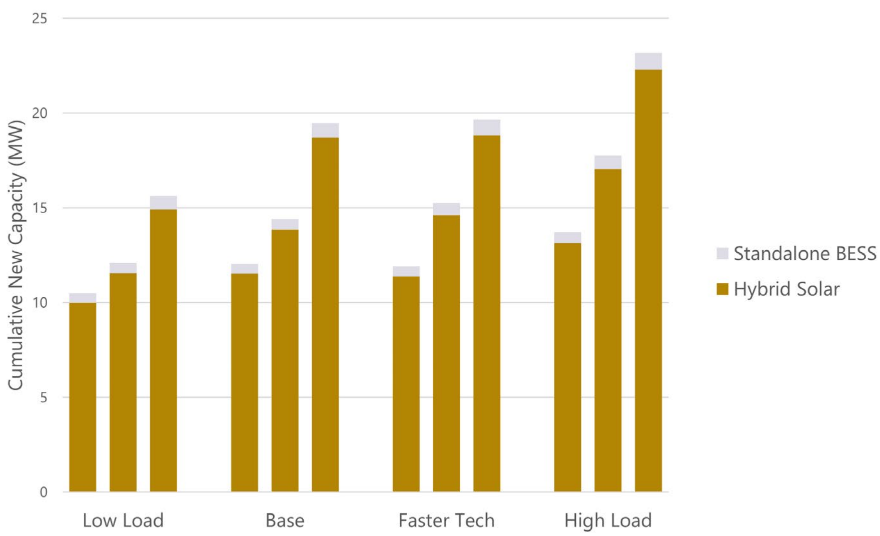


Figure 8-36. Moloka'i: cumulative new capacity selected by RESOLVE in 2030, 2035, and 2050 for the Base, Low Load, High Load, and Faster Technology Adoption scenarios

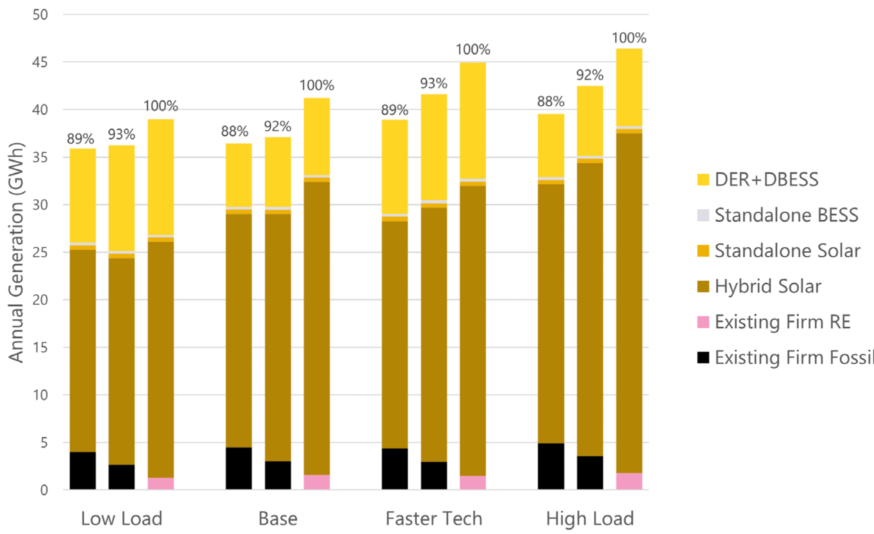


Figure 8-37. Moloka'i: annual generation and RPS from resources in 2030, 2035, and 2050 for the Base, Low Load, High Load, and Faster Technology Adoption scenarios

High Fuel Retirement Optimization Scenario

In the High Fuel Retirement Optimization scenario, shown in Figure 8-38 and Figure 8-39, RESOLVE retires approximately 10.4 MW of existing thermal generation in 2030 and builds more hybrid solar than the Base plan.

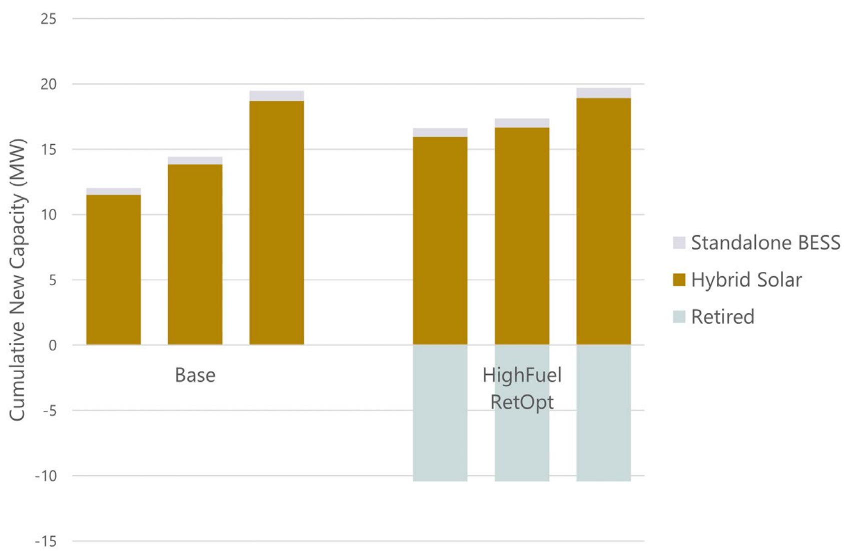


Figure 8-38. Moloka'i: cumulative new capacity selected by RESOLVE in 2030, 2035, and 2050 for the Base and High Fuel Retirement Optimization scenarios

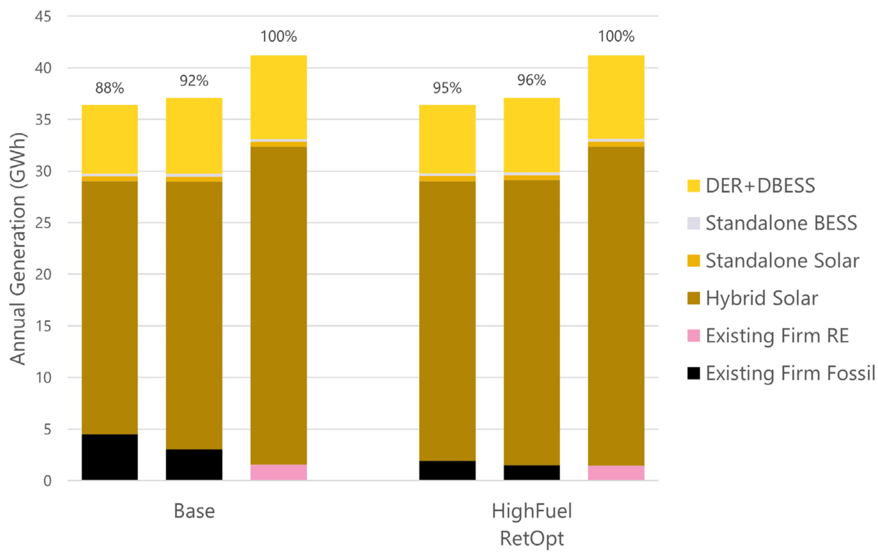


Figure 8-39. Moloka'i: annual generation and RPS from resources in 2030, 2035, and 2050 for the Base and High Fuel Retirement Optimization scenarios

8.5.2 Resource Adequacy

We did not make any retirement assumptions for Moloka'i; however, as more renewable resources are brought online, we will continue to assess resource adequacy and determine if system conditions warrant retiring existing fossil fuel–based generators.

Probabilistic Resource Adequacy Summary

The Base scenario, which assumed 15.18 MW of existing firm and 11.5 MW of future hybrid solar, showed a loss of load expectation of 0 days per year, meeting the targeted level of reliability. To create curves to illustrate the relationship between loss of load expectation and variable and firm capacity, different scenarios were run where one type of resource was held constant. In the variable resource sensitivity, the amount of firm capacity was held constant and in the firm resource sensitivity the variable resource was held constant.

The High Load scenario for these resource adequacy runs assumed the same amount of resources as the Base scenario except with a higher load. These runs still showed a loss of load expectation of 0 days per year across the board, meeting the targeted level of reliability. To create curves to illustrate the relationship between loss of load expectation and resource capacity, different scenarios were run where one type of resource was held constant. In the variable resource sensitivity, the amount of firm capacity was held constant and in the firm resource sensitivity the variable resource was held constant.

Table 8-33 presents a probabilistic resource adequacy analysis results summary for Moloka'i.

Table 8-33. Probabilistic Resource Adequacy Analysis: Results Summary, Moloka'i

Scenario	Existing Firm	New Firm	Stage 3 RFP	Future Wind	Future Hybrid Solar	Future Standalone BESS	LOLE	LOLEv	LOLH	EUE (GWh)	EUE (%)
Base 2030	15.18	0	0	0	11.5	0.5	0.00	0.00	0.00	0.00	0.00
Base no future RE 2035	15.18	0	0	0	0	0.5	0.00	0.00	0.00	0.00	0.00
High Load no future RE 2035	15.18	0	0	0	0	0.5	0.00	0.00	0.00	0.00	0.00

See Section 12 for more details on risks of the resource portfolio given uncertainties in procuring and acquiring the optimal mix of resources.

8.5.3 Grid Operations

The transition to 100% renewables will necessitate a change in how the thermal generators on our system operate. Scenarios with more renewable resources will use thermal generators less often. This is shown in the daily energy profiles and operational statistics in this section.

8.5.3.1 Status Quo Typical Operations

The Status Quo scenario does not include the hybrid solar and standalone energy storage from RESOLVE that is included in the Base scenario. Figure 8-40 and Figure 8-41 show the dispatch of the resources in a Status Quo resource plan in 2030 and 2035, respectively, for a few days with average load. With the decreased amount of hybrid solar and standalone storage, the Status Quo system still relies on existing firm units quite heavily. As shown in Figure 8-42 the load is almost completely served by the existing fossil-fuel units.

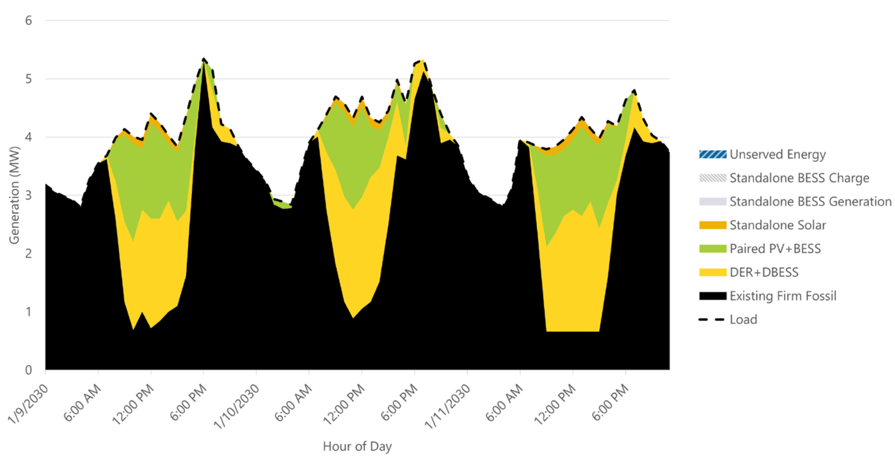


Figure 8-40. Moloka'i: detailed Status Quo energy profile, 2030 median load day (January 9–11, 2030)

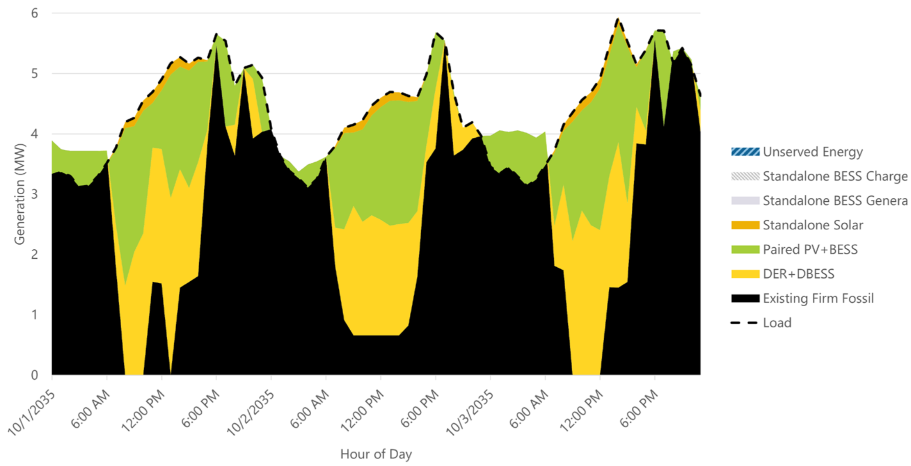
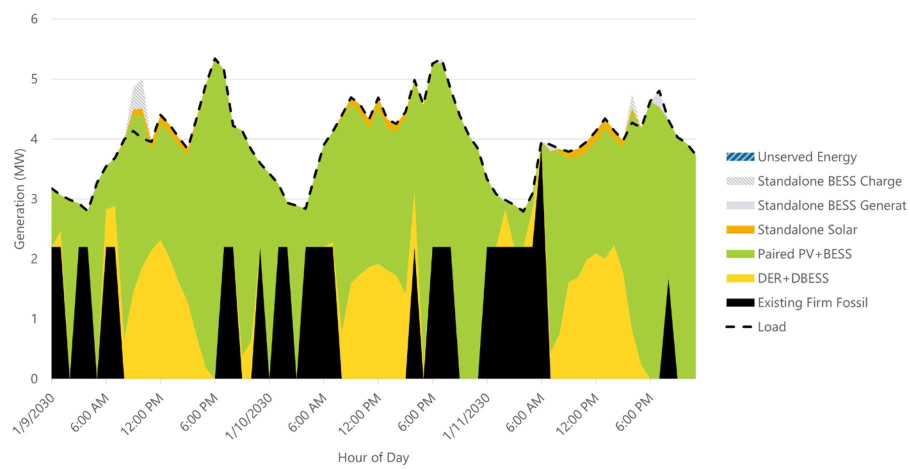


Figure 8-41. Moloka'i: detailed Status Quo energy profile, 2035 median load day (October 1–3, 2035)

8.5.3.2 Base Scenario Typical Operations

Figure 8-42 and Figure 8-43 show the dispatch of the resources in a Base scenario resource plan in 2030 and 2035, respectively, for a few days with average load. Compared to the Status Quo scenario above, the Base scenario shows a much lower reliance on the existing firm fossil units. By 2035 the system uses the existing firm fossil units much less than in the Status Quo scenario.

Figure 8-42. Moloka'i: detailed Base energy profile, 2030 median load day (January 9–11, 2030)



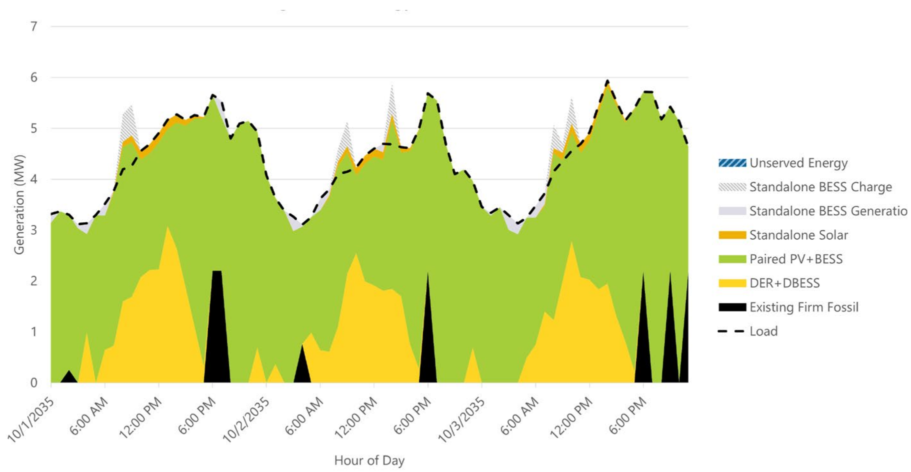
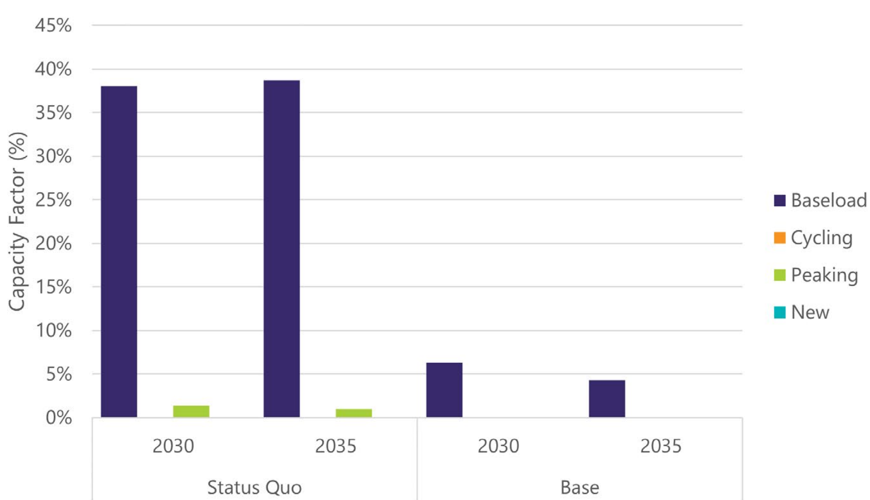


Figure 8-43. Moloka'i: detailed Base energy profile, 2035 median load day (October 1–3, 2035)

8.5.3.3 Operations of Firm Generation

Figure 8-44 and Figure 8-45 show thermal generators capacity factor and number of starts, respectively, for the 2030 and 2035 for Status Quo and Base scenarios. Without the hybrid solar and standalone storage included in the Base scenario, the system in the Status Quo scenario uses the baseloaded and peaking units a lot more, shown by the higher capacity factor of the baseload units increase over time with the load. However, because the Base scenario is less reliant on the firm units, the capacity factor for the baseload units decrease over time.

Figure 8-44. Moloka'i: utility-owned thermal generators capacity factor, 2030 and 2035 for Status Quo and Base scenario



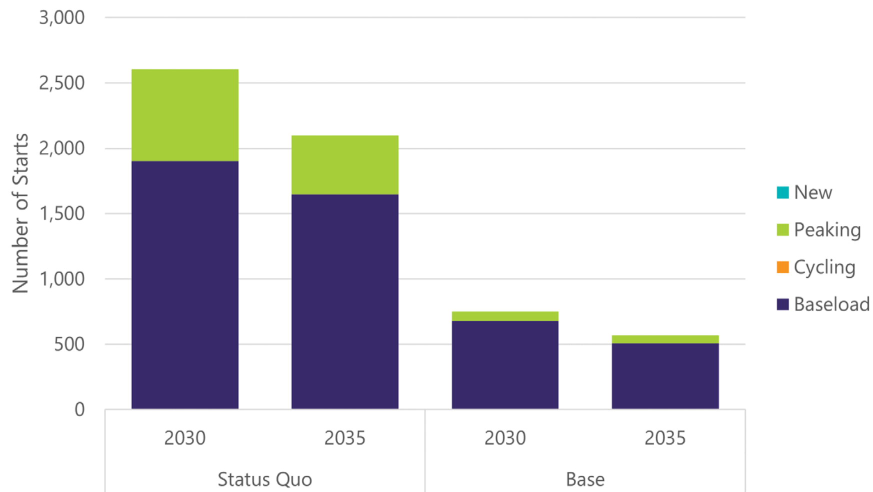


Figure 8-45. Molokaʻi: utility-owned thermal generators number of starts, 2030 and 2035 for Status Quo and Base scenario

8.5.4 System Security Needs

Molokaʻi does not have a transmission system, so our analysis did not evaluate the REZ concept; however, we performed a system stability analysis. We analyzed the Base scenario resource plan post-Stage 3 procurement and 2050. We also analyzed the High load resource plan for near-term years (i.e., between post-Stage 3 procurement and before 2040), which can be found in Appendix D. We analyzed selected years with major grid scale resource additions, including:

- Molokaʻi system Base scenario resource plan: 2029, 2030, and 2050
- Molokaʻi system High load scenario resource plan: 2029, 2030, and 2050

8.5.4.1 Summary of Base Scenario Resource Plan

We performed a system dynamic stability review with very low synchronous machine generation or no synchronous machine generation online. We evaluated system stability in the presence of a three-phase to ground fault with zero fault impedance for 2 seconds duration, or in the presence of a single phase to ground fault with 40-ohm fault impedance for 20 seconds duration.

We concluded that when powered by 100% grid-forming inverter-based resources the Molokaʻi system exhibits acceptable stability performance in the years from 2030 to 2050; however, the system may experience diesel unit out-of-synchronism issues before 2030 when the system relies on the existing diesel units.

8.5.5 Distribution Needs

This section discusses distribution needs as they pertain to the grid needs assessment for Molokaʻi.

8.5.5.1 Hosting Capacity Grid Needs

Of the eight circuits assessed on Molokaʻi, most have sufficient DER hosting capacity or could accommodate the 5-year hosting capacity without infrastructure investments. The remaining circuits where infrastructure investments are required to increase hosting capacity to accommodate the forecasted distributed energy resources are identified as requiring grid needs. Infrastructure investments or distribution upgrades (i.e., wires solutions) to mitigate the grid needs are identified with cost estimates. The grid needs and solutions are summarized in Table 8-34.

Table 8-34. Moloka'i Hosting Capacity Grid Needs (Years 2021–2025)

Parameter (Nominal $)	Base DER Forecast	High DER Forecast	Low DER Forecast
Number of grid needs	3	5	3
Cost summary (wires solutions)	$1,260,000	$1,764,000	$1,260,000

A complete list of the hosting capacity grid needs can be found in the *Distribution DER Hosting Capacity Grid Needs* report.

8.5.5.2 Location-Based Grid Needs

Of the eight circuits and two substation transformers assessed on Moloka'i, all have sufficient capacity to accommodate the forecasted load demand. No grid needs are identified.

8.5.5.3 Distribution Grid Needs Summary

The minimum number of grid needs identified (i.e., minimum wires solutions) by scenario by island is shown in Table 8-35 below. This includes both hosting capacity and location-based grid needs.

Table 8-35. Moloka'i Minimum Grid Needs Solutions Identified (Years 2023–2030)

Island (Nominal $)	Scenario 1 (Base)	Scenario 2 (High Load)	Scenario 3 (Low Load)	Scenario 4 (Faster Technology Adoption)
Number of grid needs	3	3	5	5
Cost summary (wires solutions)	$1,260,000	$1,764,000	$1,260,000	$1,260,000

8.5.5.4 NWA Opportunities

No NWA opportunities are identified for Moloka'i.

8.5.6 Preferred Plan

The capacity expansion modeling conducted in RESOLVE was the starting point for identifying grid needs and developing a resource plan. Battery duration was increased to 4 hours to match current market conditions. We then performed probabilistic resource adequacy analyses to confirm that the portfolio of resources selected in the resource plan were reliable. No additional system constraints or transmission costs were identified.

8.6 Lāna‘i

This section describes the results of the grid needs assessment for Lāna‘i through the multistep process that includes modeling capacity expansion, resource adequacy, operations of the system, transmission and system security needs, distribution needs, and iterations or adjustments made to determine the preferred plan.

8.6.1 Capacity Expansion Scenarios

The Lāna‘i CBRE request for proposal targeting 35.8 GWh of variable renewable energy, which translates to approximately 16 MW hybrid solar, will bring Lāna‘i to nearly 100% renewable portfolio standard. There could be an additional 5 MW hybrid solar (Base scenario) by 2030 and remain cost-effective. The CBRE request for proposal may also allow for deactivation of fossil fuel–based generation.

Similar amounts of hybrid solar and standalone BESS are selected across the different scenarios in addition to the 16 MW hybrid solar modeled for the CBRE request for proposal.

There is uncertainty surrounding the resorts, which represents nearly 50% of Lāna‘i’s load today. The CBRE request for proposal may be oversized if the resorts exit the grid. The hybrid solar proxy resource for the CBRE request for proposal was removed in the No Resorts scenario. The model was allowed to re-optimize and selected approximately 10 MW hybrid solar, a smaller amount than the CBRE request for proposal target.

Figure 8-46 shows cumulative new capacity and Figure 8-47 shows annual generation and renewable portfolio standards for Lāna‘i.

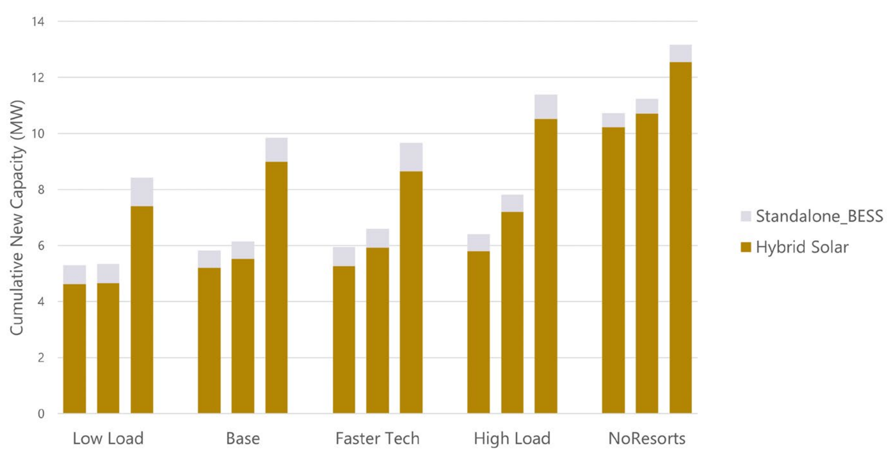


Figure 8-46. Lāna‘i: cumulative new capacity selected by RESOLVE in 2030, 2035, and 2050 for the Base, Low Load, High Load, Faster Technology Adoption, and No Resorts scenarios

Lāna‘i achieves nearly 100% renewable portfolio standard with the CBRE request for proposal and additional hybrid solar selected by RESOLVE. The existing fossil fuel–powered firm generation is converted to 100% biofuel by 2045.

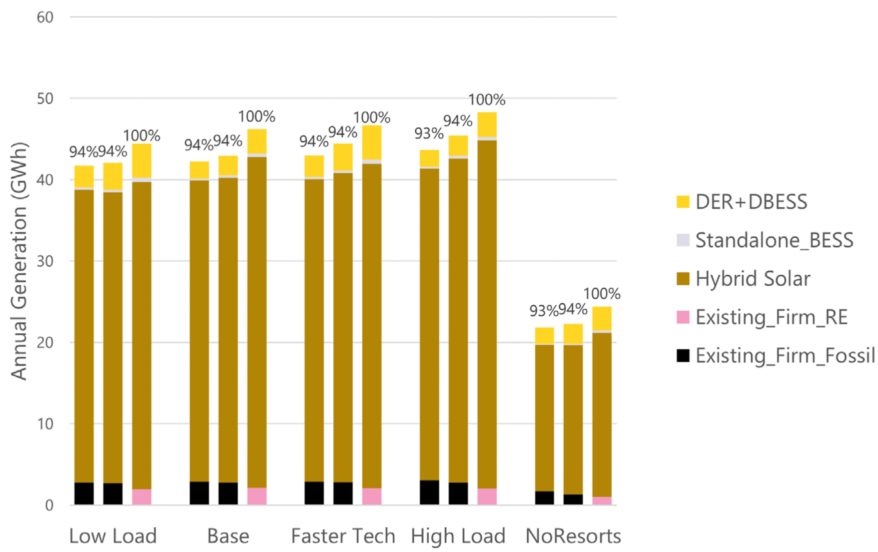


Figure 8-47. Lāna'i: annual generation and RPS from resources in 2030, 2035, and 2050 for the Base, Low Load, High Load, Faster Technology Adoption, and No Resorts scenarios

8.6.1.1 High Fuel Retirement Optimization Scenario

The High Fuel Retirement Optimization scenario retired 5 MW of existing fossil fuel–based generation upfront in 2030. Because RESOLVE performs a linear optimization, the additional retirements may consist of partial unit retirements. RESOLVE builds hybrid solar to replace the retired capacity. RESOLVE builds 0.3 MW biofuel-based generation by 2050. Figure 8-48 shows cumulative new capacity and Figure 8-49 shows annual generation and renewable portfolio standards for Lāna'i.

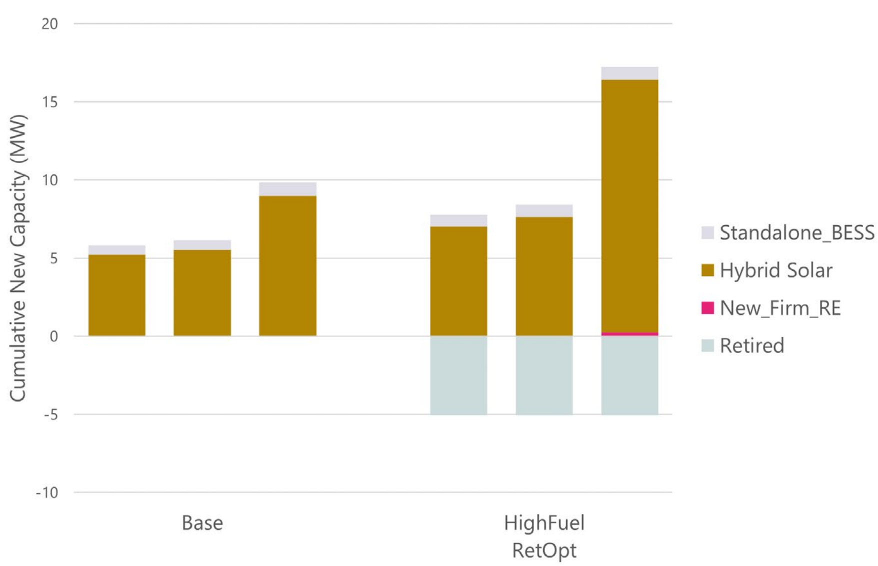


Figure 8-48. Lāna'i: cumulative new capacity selected by RESOLVE in 2030, 2035, and 2050 for the Base and High Fuel Retirement Optimization scenarios

Although 5 MW of existing fossil fuel–based generation is removed in the High Fuel Retirement Optimization scenario, the annual generation is similar between the Base and High Fuel scenarios.

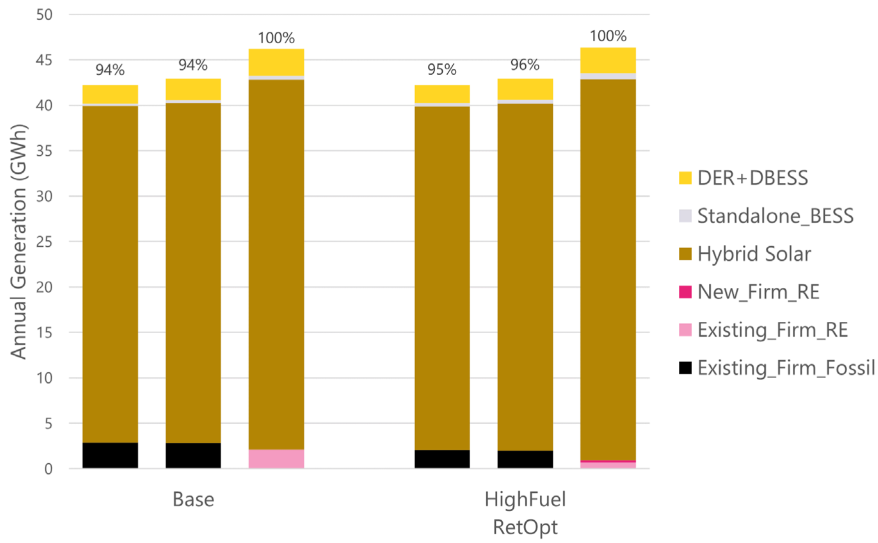


Figure 8-49. Lānaʻi: annual generation and RPS from resources in 2030, 2035, and 2050 for the Base and High Fuel Retirement Optimization scenarios

8.6.2 Resource Adequacy

We did not make any retirement assumptions for Lānaʻi; however, as more renewable resources are brought online, we will continue to assess resource adequacy and determine if system conditions warrant retiring existing fossil fuel–based generators.

Probabilistic Resource Adequacy Summary

The Base resource plan in 2030 includes 10 MW existing firm, 16 MW hybrid solar for the CBRE request for proposal, 5 MW future hybrid solar, and 0.6 MW standalone BESS. The loss of load expectation is 0 days per year and no unserved energy is observed in the 250 samples.

For the 2035 outlook, we analyzed the High Load scenario. The High Electricity demand resource plan in 2035 includes 10 MW existing firm, 16 MW hybrid solar for the CBRE request for proposal, 7 MW future hybrid solar, and 0.6 MW standalone BESS. The loss of load expectation is 0 days per year and no unserved energy is observed in the 250 samples.

Table 8-36 presents a probabilistic resource adequacy analysis results summary for Lānaʻi.

Table 8-36. Probabilistic Resource Adequacy Analysis: Results Summary, Lānaʻi

Scenario	Existing Firm	New Firm	CBRE RFP	Future Wind	Future Hybrid Solar	Future Standalone BESS	LOLE	LOLEv	LOLH	EUE (GWh)	EUE (%)
Base: 2030	10	0	16	0	5.2	0.6	0	0	0	0	0
Base: 2035	10	0	16	0	5.5	0.6	0	0	0	0	0
High: 2035	10	0	16	0	7.2	0.6	0	0	0	0	0

See Section 12 for more details on risks of the resource portfolio given uncertainties in procuring and acquiring the optimal mix of resources.

8.6.3 Grid Operations

The transition to 100% renewables will necessitate a change in how the thermal generators on our system operate. Scenarios with more renewable resources will use thermal generators less often. This is shown in the daily energy profiles and operational statistics in this section.

8.6.3.1 Status Quo Typical Operations

The Status Quo resource plan includes the existing fossil fuel–based generation and a proxy resource for the 17.5 MW hybrid solar project selected through the CBRE RFP. There are no additional future resources.

Figure 8-50 and Figure 8-51 show the dispatch of the resources in the Status Quo resource plan in 2030 and 2035, respectively, for a few days with average load. The load is carried primarily by hybrid solar and BESS. Fossil fuel–based generation is dispatched during the evening and can be dispatched during the day when there is insufficient solar.

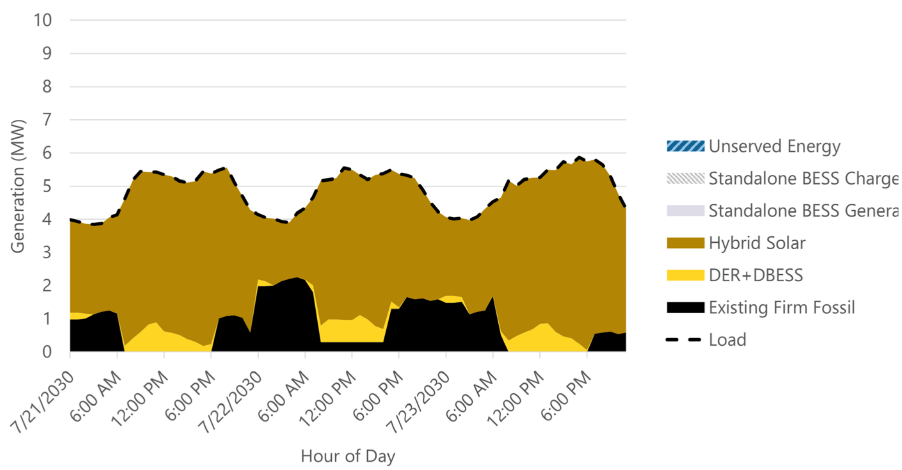


Figure 8-50. Lāna'i: detailed Status Quo energy profile, 2030 median load day (July 21–23, 2030)

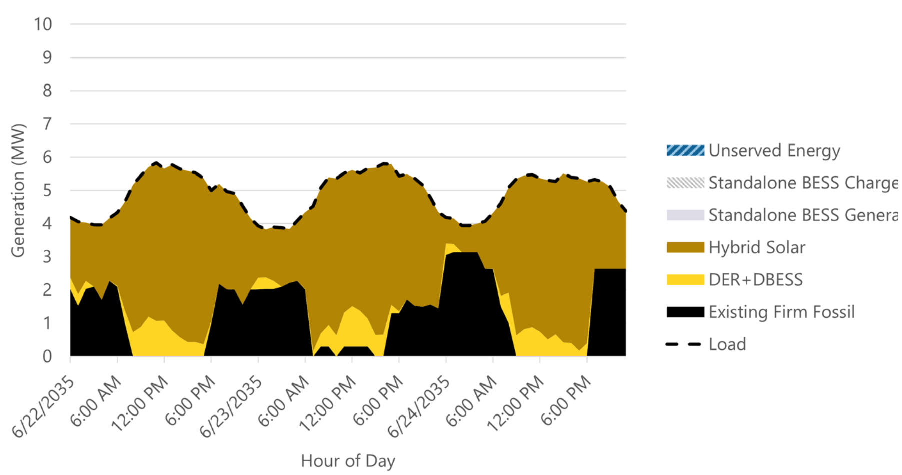


Figure 8-51. Lāna'i: detailed Status Quo energy profile, 2035 median load day (June 22–24, 2035)

8.6.3.2 Base Scenario Typical Operations

The Base resource plan includes the existing fossil fuel–based generation, the CBRE request for proposal, and additional future resources selected by RESOLVE.

Figure 8-52 and Figure 8-53 show the dispatch of the resources in the Base resource plan in 2030 and 2035, respectively, for a few days with average load. The additional future resources selected by RESOLVE displace almost all of the fossil fuel–based generation seen above for the Status Quo scenario. Fossil fuel–based generation is mostly dispatched at night.

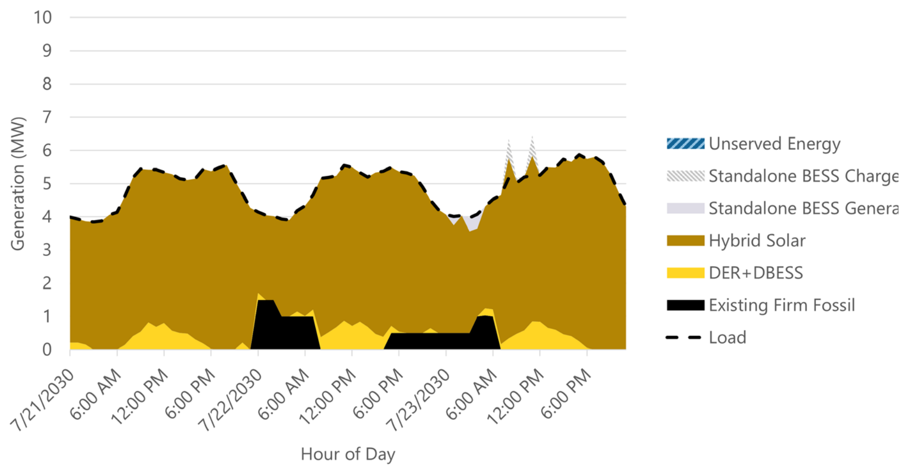


Figure 8-52. Lānaʻi: detailed Base energy profile, 2030 median load day (July 21–23, 2030)

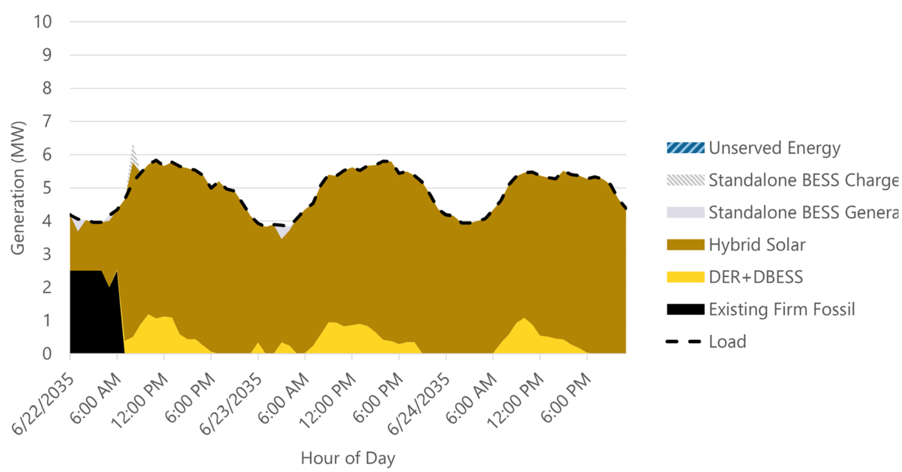


Figure 8-53. Lānaʻi: detailed Base energy profile, 2035 median load day (June 22–24, 2035)

8.6.3.3 Operations of Firm Generation

Figure 8-54 and Figure 8-55 show the number of generator starts and the generator capacity factor in 2030 and 2035 for the Status Quo and Base scenarios. Fossil fuel–based generation is dispatched significantly less in the Base scenario compared to Status Quo.

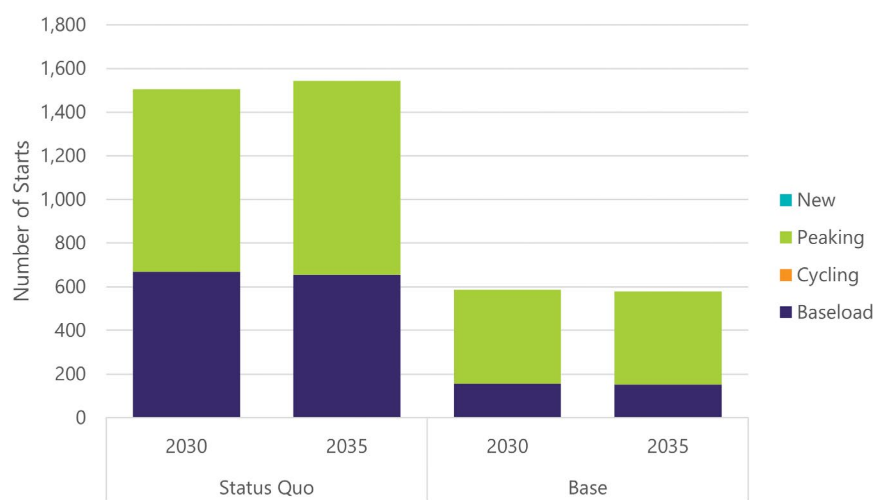


Figure 8-54. Lāna'i: thermal generators number of starts, 2030 and 2035 for Status Quo and Base scenario

Figure 8-55. Lāna'i: thermal generators capacity factor, 2030 and 2035 for Status Quo and Base scenario

8.6.4 System Security Needs

Lāna'i does not have a transmission system, so our analysis did not evaluate the REZ concept; however, we performed a system stability analysis. We analyzed the Base scenario resource plan post-Stage 3 procurement and 2050. We also analyzed the High load resource plan for near-term years (i.e., between post-Stage 3 and before 2040), which can be found in Appendix D. We analyzed selected years with major grid scale resource additions, including:

- Lāna'i system Base scenario resource plan: 2029 and 2050
- Lāna'i system High load scenario resource plan: 2029 and 2050
- Lāna'i system No Resort scenario resource plan: 2029, 2030, and 2050

8.6.4.1 Summary of Base Resource Plan

For Lāna'i, we performed a system dynamic stability review with very low synchronous machine generation or no synchronous machine generation online. We evaluated system stability in the presence of a three-phase to ground fault with zero fault impedance for 2 seconds duration, or in the presence of a single phase to ground fault with 40-ohm fault impedance for 20 seconds duration.

We concluded that when powered by 100% grid-forming inverter-based resources the Lānaʻi system in the scenario without resort load, exhibits acceptable system stability performance in the years from 2030 to 2050. The system may exhibit diesel unit out-of-synchronism before 2029 when the system relies on the exisitng diesel units. In the scenario with the resort load, the system has a large grid-forming inverter-based resource (with 15.8 MW capcity). In this scenario, the system survives both the 2 seconds duration three-phase to ground fault and the 20 seconds high impedance single phase to ground fault.

8.6.5 Distribution Needs

This section discusses distribution needs as they pertain to the grid needs assessment for Lānaʻi.

8.6.5.1 Hosting Capacity Grid Needs

Of the three circuits assessed on Lānaʻi, two have insufficient DER hosting capacity to accommodate the 5-year hosting capacity without infrastructure investments and require grid needs. Infrastructure investments or distribution upgrades (i.e., wires solutions) to mitigate the grid needs are identified with cost estimates. The grid needs and solutions are summarized in Table 8-37.

Table 8-37. Lānaʻi Hosting Capacity Grid Needs (Years 2021–2025)

Parameter (Nominal $)	Base DER Forecast	High DER Forecast	Low DER Forecast
Number of grid needs	2	2	2
Cost summary (wires solutions)	$504,000	$504,000	$504,000

A complete list of the hosting capacity grid needs can be found in the *Distribution DER Hosting Capacity Grid Needs* report.

8.6.5.2 Location-Based Grid Needs

Of the three circuits and one substation transformer assessed on Lānaʻi, all have sufficient capacity to accommodate the forecasted load demand. No grid needs are identified.

8.6.5.3 Distribution Grid Needs Summary

The minimum number of grid needs identified (i.e., minimum wires solutions) by scenario by island is shown in Table 8-38. This includes both hosting capacity and location-based grid needs.

Table 8-38. Lānaʻi Minimum Grid Needs Solutions Identified (Years 2023–2030)

Island (Nominal $)	Scenario 1 (Base)	Scenario 2 (High Load)	Scenario 3 (Low Load)	Scenario 4 (Faster Technology Adoption)
Number of grid needs	2	2	2	2
Cost summary (wires solutions)	$504,000	$504,000	$504,000	$504,000

8.6.5.4 NWA Opportunities

No NWA opportunities are identified for Lānaʻi.

8.6.6 Preferred Plan

The capacity expansion modeling conducted in RESOLVE was the starting point for identifying grid needs and developing a resource plan. Battery duration was increased to 4 hours to match current market conditions. We then performed probabilistic resource adequacy analyses to confirm that the portfolio of resources selected in the resource plan were reliable. No additional system constraints or transmission costs were identified.

9. Customer Impacts

In Section 8, we conducted a grid needs assessment to determine the optimal, Preferred Plans that meet reliability standards while achieving 100% renewable energy by 2045. In this section we examine the financial and environmental impacts to customers of those Preferred Plans by assessing bill impacts and carbon emissions.

Customers continue to stress the importance of affordability, and the State has set ambitious decarbonization targets to achieve economy-wide 50% carbon emissions reduction by 2030 and net negative carbon emissions reductions by 2045 compared to 2005 levels. We found that our Preferred Plans stabilize electric bills and rates and reduce emissions for the good of the environment. Under the Preferred Plans, bills are relatively flat (and in some cases lower) over the long term despite increasing revenue requirements that are needed to enable the grid to integrate more renewables and electrify the transportation sector.

Our ambitious Preferred Plans also have the potential to reduce carbon emissions by 75% in 2030 compared to 2005 levels. However, in 2030 in a Land-Constrained scenario, carbon emissions are nearly two times the Base Preferred Plan. By 2045, our Preferred Plans achieve 94% carbon emissions reductions; achieving net zero will require natural carbon sinks or advancements in negative emissions technologies. Electrification of transportation results in significant carbon reductions through 2050.

9.1 Financial and Bill Analysis

This section provides the financial analyses of the Integrated Grid Plan. It presents the strategies needed to swiftly decarbonize the electric grid and manage risks to affordability, resilience, and reliability and each island's residential customer electricity rate and bill impacts for the Preferred Plans compared to the Status Quo. These analyses should not be used as precise long-term projections of customer rates. The value of these projections is not in the precise values but in the relative results of planning to inform a Preferred Plan. Actual values could vary significantly with changes in assumptions including resource costs, detailed engineering, new renewable technologies, fuel prices, energy efficiency, tax policy, fiscal policy, and other factors.

The following information is provided by island:

- Revenue requirements
- Capital expenditures
- Residential customer bill and rate impacts

9.1.1 Revenue Requirements

The revenue requirement calculations include the investments needed to create a modern and resilient grid for our Preferred Plans and Status Quo scenarios. The calculations include operating and maintenance costs, taxes other than income, and return on existing and future utility asset investments.

Although revenue requirements will increase in the transition to clean energy, they will be lower than if we continue to supply the grid with fossil fuel–based generation.

If land for renewable projects is more limited in the future, we will need to consider higher-cost alternatives. If low-cost renewables are not available in sufficient quantities such as in the Land-Constrained scenario, higher-cost alternatives such as increased use of biofuels will need to be considered to meet decarbonization goals.

9.1.2 Capital Expenditures

Capital expenditure projections in distribution upgrades, expanding or creating new transmission interconnection points between renewable projects, improving the resilience of the transmission and distribution grid, and all other utility capital expenditures (referred to as "balance-of-utility business capital expenditures") are included in the analysis.

- Distribution upgrades are needed to support electrification and expansion of private rooftop solar hosting capacity, and support expanded distribution capacity for new housing and commercial developments.[34]
- Transmission network expansion and infrastructure to enable renewable energy zones are needed to create hubs and enabling transmission facilities for large-scale projects that will streamline interconnection and provide access to untapped renewable potential and growth in electrified loads.
- Resilience grid investments are needed to prepare the grid to withstand natural disasters and support deploying microgrids. This also includes the complete rollout of advanced metering infrastructure of phase 2 grid modernization to enhance system reliability and resilience. The capital expenditures for these two programs assume that we will receive funding through IIJA to offset the program costs.
- Balance-of-utility capital expenditures represent all other utility investments.

9.1.3 Residential Customer Bill and Rate Impacts

The residential customer bill and rate impacts uses the Annual Revenue Adjustment (ARA) approach, illustrating the bill impact of incremental Integrated Grid Plan revenue requirement costs and savings through the Energy Cost Recovery Clause (ECRC), Purchased Power Adjustment Clause (PPAC), and Revenue Balancing Account (RBA) rates. These terms are defined below:

- ARA is an annual adjustment to target revenues based on an ARA formula.
- ECRC includes the cost for utility fuel and purchased energy from independent power producers.
- PPAC includes the payments for capacity and operation and maintenance, and lump-sum payments, to independent power producers.
- RBA, among other items, includes decoupling, the ARA, and the Extraordinary Project Recovery Mechanism (EPRM).

The overall impact on a residential customer's bill is the combination of usage and rates. Residential customer rates were modeled using existing customer and non-fuel energy charges, the ECRC revenue requirement allocated across projected kWh sales, the PPAC revenue requirement for residential allocated across projected residential

[34] We note that while the transmission needs analysis evaluated infrastructure needed to support electrification through 2050, the distribution needs analysis did not evaluate infrastructure required to support electrification beyond 2030.

kWh sales, and the RBA revenue requirement divided by the sum of base and PPAC revenue, to be applied as a percentage to the customer's base and PPAC charges in this illustration. Over the planning period, residential kWh sales are projected to increase as a result of electrification of transportation. As a result of increasing revenue requirement in combination with increasing sales, residential customer bills and rates are projected to remain relatively flat over the planning period, demonstrating the benefits of electrification of the transportation sector.

9.2 Oʻahu Financial Impacts

The data and analyses presented in this section cover the Oʻahu service territory and customers. For Oʻahu, the Base Preferred Plan shows the lowest overall revenue requirements over the 2023 to 2050 planning period.

9.2.1 Revenue Requirements

Table 9-1 shows the net present value (NPV) of the annual revenue requirements for the Base and Land-Constrained Preferred Plan and Status Quo scenarios.

Table 9-1. Net Present Value of Revenue Requirement

NPV of Revenue Requirement ($000)	($000)	% Increase from Lowest-Cost Scenario
Base scenario	$29,397,330	-
Status Quo scenario	$33,886,081	15%
Land-Constrained scenario	$30,357,218	3%

Figure 9-1 illustrates the annual revenue requirements in nominal dollars for all three scenarios.

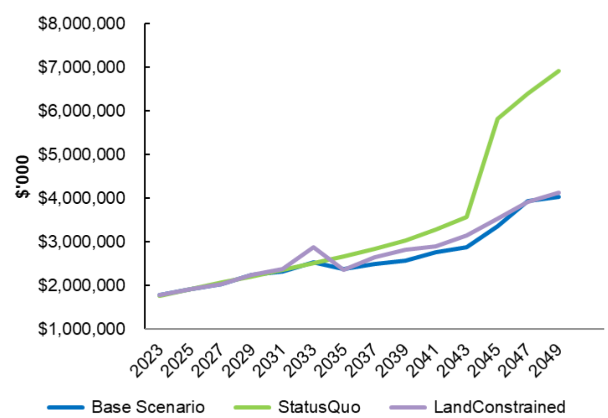


Figure 9-1. Oʻahu: comparison of revenue requirement (nominal $)

9.2.2 Capital Expenditure Projections

Table 9-2, Table 9-3, and Table 9-4 summarize the capital expenditures identified in the Base Preferred Plan, Status Quo and Land-Constrained Preferred Plan, respectively.

Table 9-2. Capital Expenditures (Nominal $): Base Scenario Preferred Plan

('000)	2023–25	2026–30	2031–35	2036–40	2041–45	2046–50	Total
Distribution upgrades	$12,527	$39,278	$0	$0	$0	$0	$51,805
Transmission interconnection	$22,794	$1,032,990	$62,456	$798,919	$5,723,323	$2,129,656	$9,770,138
Resilience [a]	$12,768	$36,831	$0	$0	$0	$0	$49,599
Grid mod phase 2 [a]	$14,501	$11,965	$0	$0	$0	$0	$26,466
Balance-of-utility business	$622,756	$914,143	$924,602	$1,032,996	$1,052,278	$1,156,684	$5,703,458
Total	$685,346	$2,035,207	$987,058	$1,831,915	$6,775,601	$3,286,340	$15,601,466

a. Final costs to be submitted in a forthcoming application.

Table 9-3. Capital Expenditures (Nominal $): Status Quo Scenario

('000)	2023–25	2026–30	2031–35	2036–40	2041–45	2046–50	Total
Distribution upgrades	$12,527	$39,278	$0	$0	$0	$0	$51,805
Transmission interconnection	$0	$0	$0	$0	$528,500	$293,100	$821,600
Resilience [a]	$12,768	$36,831	$0	$0	$0	$0	$49,599
Grid mod phase 2 [a]	$14,501	$11,965	$0	$0	$0	$0	$26,466
Balance-of-utility business	$630,153	$1,015,547	$1,105,691	$1,091,971	$1,124,389	$1,191,265	$6,159,017
Total	$669,949	$1,103,621	$1,105,691	$1,091,971	$1,652,889	$1,484,365	$7,108,487

a. Final costs to be submitted in a forthcoming application.

Table 9-4. Capital Expenditures (Nominal $): Land-Constrained Scenario Preferred Plan

('000)	2023–25	2026–30	2031–35	2036–40	2041–45	2046–50	Total
Distribution upgrades	$12,527	$39,278	$0	$0	$0	$0	$51,805
Transmission interconnection	$0	$0	$62,456	$0	$1,990,600	$293,100	$2,346,156
Resilience [a]	$12,768	$36,831	$0	$0	$0	$0	$49,599
Grid mod phase 2 [a]	$14,501	$11,965	$0	$0	$0	$0	$26,466
Balance-of-utility business	$622,756	$914,143	$924,602	$1,032,996	$1,052,278	$1,156,684	$5,703,458
Total	$662,552	$1,002,217	$987,058	$1,032,996	$3,042,878	$1,449,784	$8,177,484

a. Final costs to be submitted in a forthcoming application.

9.2.3 Residential Customer Bill and Rate Impacts

As a result of an increasing revenue requirement in combination with increasing sales because of electrification, residential customer rates and bills are projected to remain relatively flat during the planning period for all scenarios, demonstrating the benefits of electrification of the transportation sector.

Table 9-5 shows the average annual residential bill increases for all scenarios; however, the smallest increase occurs in the Base Preferred Plan scenario. The bill increase in the Land-Constrained Preferred Plan is also less than the increase in the Status Quo scenario.

Table 9-5. Average Annual Residential Bill Increases

Average Annual Bill Increase (2023–2050)	Nominal $
Base scenario	1.28%
Status Quo scenario	3.70%
Land-Constrained scenario	1.32%

Figure 9-2 illustrates the residential customer bill impact in nominal dollars for a typical 500 kWh bill for the three scenarios.

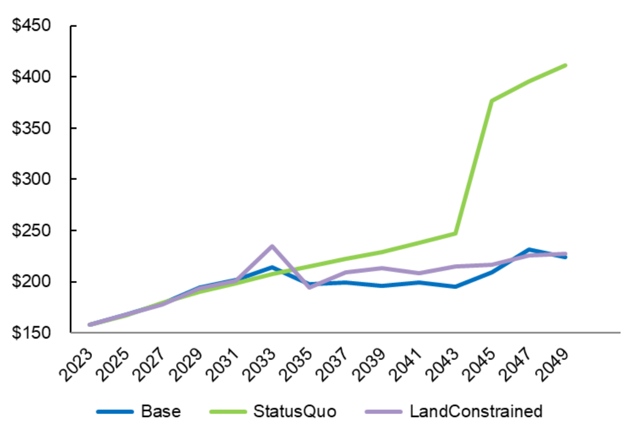


Figure 9-2. O'ahu: typical monthly residential bill (nominal $)

Figure 9-3 illustrates the residential customer rates nominal dollars for the three scenarios.

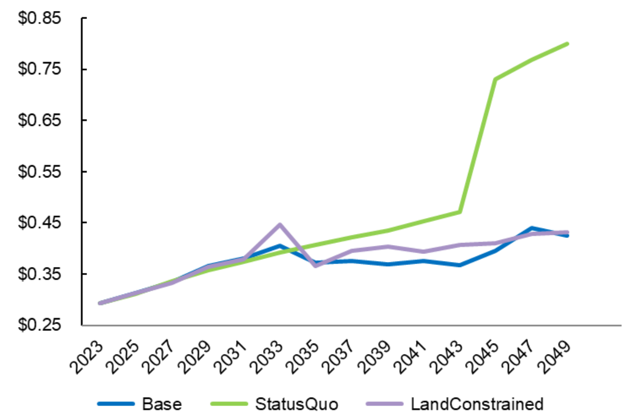


Figure 9-3. O'ahu: residential rates (nominal $)

Figure 9-4, Figure 9-5, and Figure 9-6 illustrate the cost components to residential customer rates in nominal dollars for the Base Preferred Plan, Status Quo, and Land-Constrained Preferred Plan, respectively. The ECRC component of residential rates makes up a larger portion of the total rate in the Status Quo and Land-Constrained scenarios compared to the Base Preferred Plan, and therefore has higher exposure to rate volatility because of fuel prices. In the Base Preferred Plan scenario, PPAC increases while ECRC declines because of the increase in fixed-cost PPAs for hybrid solar, wind, and energy storage, and less dependency on fuel-based generation and energy-based PPAs. The Base Preferred Plan scenario RBA component increases because of the investment needed in transmission and distribution infrastructure to enable renewables and electrification.

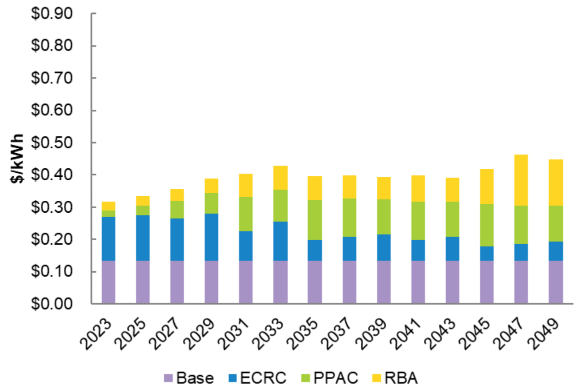


Figure 9-4. O'ahu: cost components to residential rates, Base scenario (nominal $)

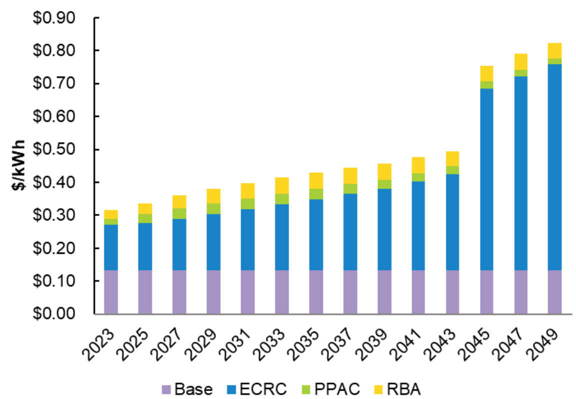


Figure 9-5. O'ahu: cost components to residential rates, Status Quo scenario (nominal $)

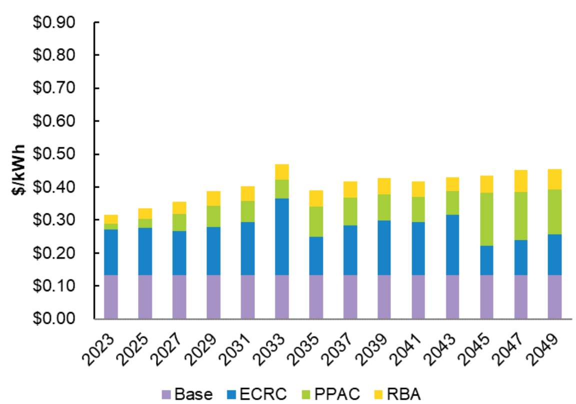


Figure 9-6. O'ahu: cost components to residential rates, Land-Constrained scenario (nominal $)

9.3 Hawai'i Island Financial Impacts

The data and analyses presented in this section cover the Hawai'i Island service territory and customers. For Hawai'i Island, the Base Preferred Plan shows the lowest overall revenue requirements over the 2023 to 2050 planning period.

9.3.1 Revenue Requirements

Table 9-6 shows the NPV of the annual revenue requirements for the Base Preferred Plan and Status Quo scenarios.

Table 9-6. Net Present Value of Revenue Requirement

NPV of Revenue Requirement ($000)	($000)	% Increase from Lowest-Cost Scenario
Base scenario	$4,683,848	-
Status Quo scenario	$5,596,654	19%

Figure 9-7 illustrates the annual revenue requirements in nominal dollars for the two scenarios.

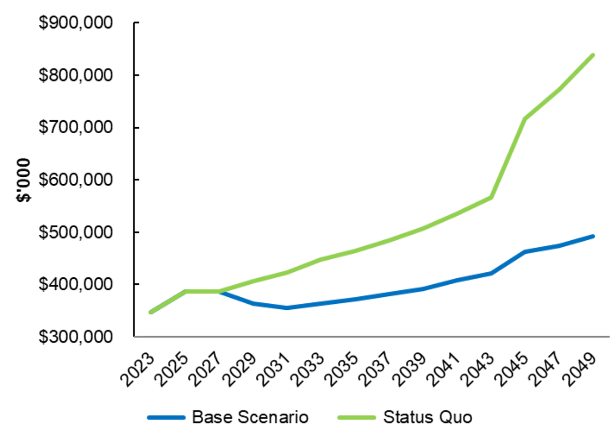


Figure 9-7. Hawai'i Island: comparison of revenue requirement (nominal $)

9.3.2 Capital Expenditure Projections

Table 9-7 and Table 9-8 summarize the capital expenditures identified in Status Quo and Preferred Plan, by category.

Table 9-7. Capital Expenditures (Nominal $): Base Scenario

('000)	2023–25	2026–30	2031–35	2036–40	2041–45	2046–50	Total
Distribution upgrades	$3,310	$0	$0	$0	$0	$0	$3,310
Transmission interconnection	$9,002	$36,010	$3,230	$24,158	$0	$25,848	$98,248
Resilience [a]	$4,401	$12,052	$0	$0	$0	$0	$16,453
Grid mod phase 2 [a]	$2,887	$12,563	$0	$0	$0	$0	$15,450
Balance-of-utility business	$134,806	$226,859	$250,420	$276,484	$305,261	$337,032	$1,530,863
Total	$154,407	$287,484	$253,650	$300,642	$305,261	$362,880	$1,664,324

a. Final costs to be submitted in a forthcoming application.

Table 9-8. Capital Expenditures (Nominal $): Status Quo Scenario

('000)	2023–25	2026–30	2031–35	2036–40	2041–45	2046–50	Total
Distribution upgrades	$3,310	$0	$0	$0	$0	$0	$3,310
Transmission interconnection	$0	$77,026	$19,257	$0	$0	$0	$96,283
Resilience [a]	$4,401	$12,052	$0	$0	$0	$0	$16,453
Grid mod phase 2 [a]	$2,887	$12,563	$0	$0	$0	$0	$15,450
Balance-of-utility business	$134,806	$226,859	$250,420	$276,484	$305,261	$337,032	$1,530,863
Total	$145,404	$328,500	$269,677	$276,484	$305,261	$337,032	$1,662,359

a. Final costs to be submitted in a forthcoming application.

9.3.3 Residential Customer Bill and Rate Impacts

As a result of an increasing revenue requirement in combination with increasing sales because of electrification, residential customer rates and bills are projected to remain relatively flat during the planning period for the Base Preferred Plan, demonstrating the benefits of electrification of the transportation sector. This is especially true on Hawai'i Island in 2045 and beyond where, despite an increase in revenue requirement, electric bills decrease.

Table 9-9 shows the average annual residential bill increase in the Status Quo scenario and decrease in the Base Preferred Plan.

Table 9-9. Average Annual Residential Bill Increases

Average Annual Bill Increase (2023–2050)	Nominal $
Base scenario	(0.09)%
Status Quo scenario	2.15%

Figure 9-8 illustrates the residential customer bill impact in nominal dollars for a typical 500 kWh bill for the two scenarios.

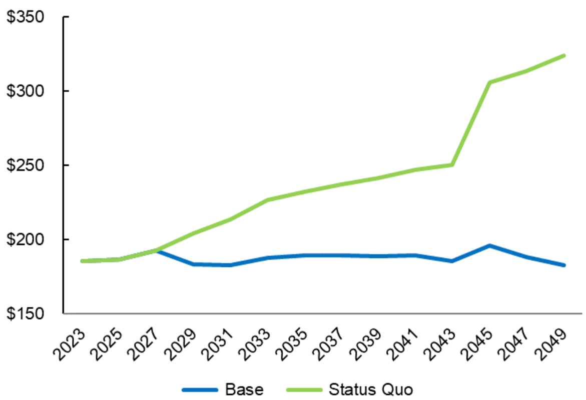


Figure 9-8. Hawai'i Island: residential bill (nominal $)

Figure 9-9 illustrates the residential customer rates in nominal dollars for the two scenarios.

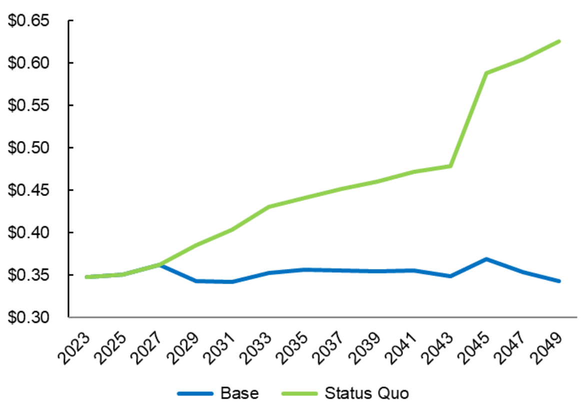


Figure 9-9. Hawai'i Island: residential rates (nominal $)

Figure 9-10 and Figure 9-11 illustrate the cost components to residential customer rates in nominal dollars for the Base Preferred Plan and Status Quo, respectively. The ECRC component of residential rates makes up a larger portion of the total rate in the Status Quo compared to the Base Preferred Plan, and therefore has higher exposure to rate volatility because of fuel prices. In the Base Preferred Plan scenario, PPAC increases while ECRC declines because of the increase in fixed-cost PPAs for hybrid solar, wind, and energy storage, and less dependency on fuel-based generation and energy-based PPAs. The Base Preferred Plan scenario RBA component increases because of the investment needed in transmission and distribution infrastructure to enable renewables and electrification.

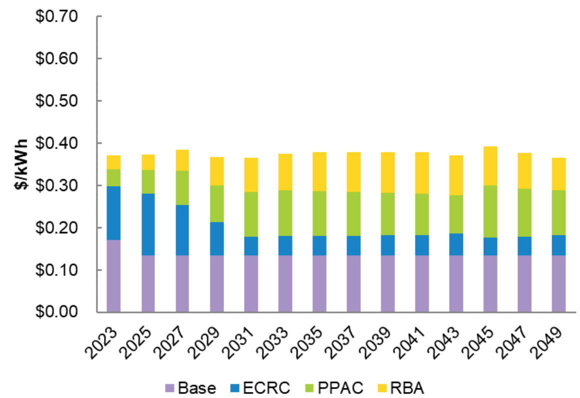


Figure 9-10. Hawai'i Island: cost components to residential rates, Base scenario (nominal $)

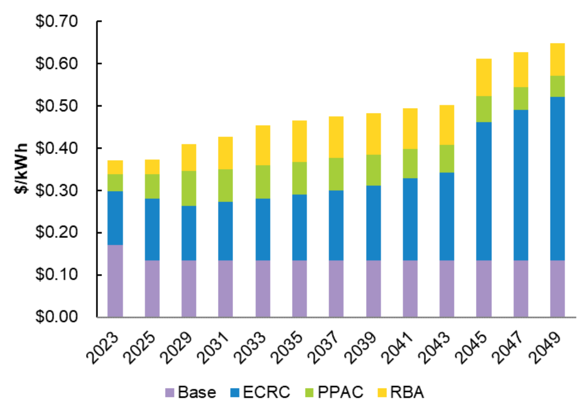


Figure 9-11. Hawai'i Island: cost components to residential rates, Status Quo scenario (nominal $)

9.4 Maui County Financial Impacts

The data and analyses presented in this section cover the Maui County service territory and customers, and are broken out individually for Maui, Molokaʻi, and Lānaʻi, unless clearly noted. The Base scenario shows the lowest overall revenue requirements over the 2023 to 2050 planning period for all three islands.

9.4.1 Revenue Requirements

Table 9-10 shows the NPV of the annual revenue requirements for the Base Preferred Plan and Status Quo scenarios for Maui, Molokaʻi, and Lānaʻi.

Table 9-10. Net Present Value of Revenue Requirement

NPV of Revenue Requirement ($000)	($000)	% Increase from Lowest-Cost Scenario
Base scenario: Maui	$4,769,387	-
Status Quo scenario: Maui	$5,305,202	11%
Base scenario: Molokaʻi	$152,650	-
Status Quo scenario: Molokaʻi	$179,995	18%
Base scenario: Lānaʻi	$177,201	-
Status Quo scenario: Lānaʻi	$190,209	7%

Figure 9-12 illustrates Maui's annual revenue requirements in nominal dollars.

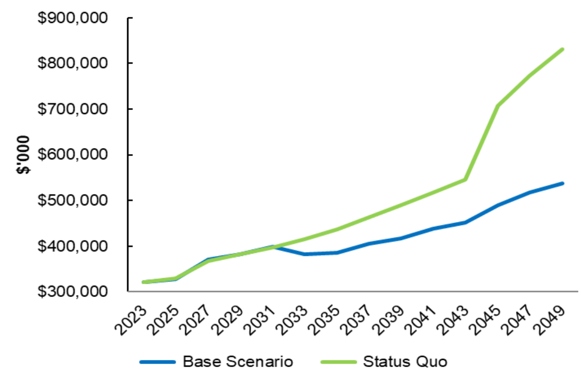


Figure 9-12. Maui: comparison of revenue requirement (nominal $)

Figure 9-13 illustrates Molokaʻi's annual revenue requirements in nominal dollars.

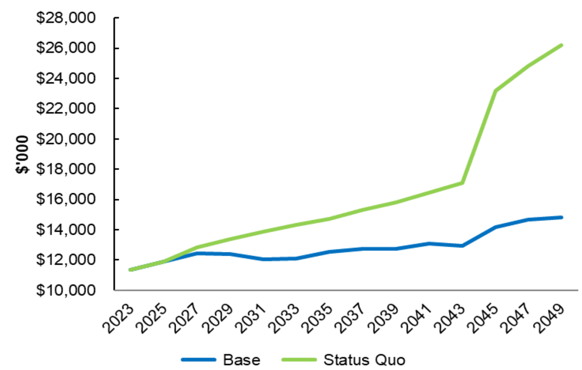


Figure 9-13. Molokaʻi: comparison of revenue requirement (nominal $)

Figure 9-14 illustrates Lānaʻi's annual revenue requirements in nominal dollars.

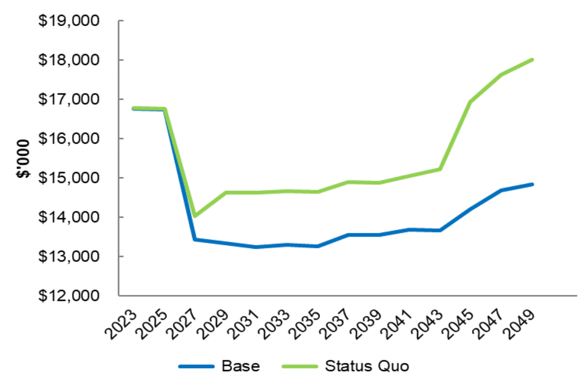


Figure 9-14. Lānaʻi: comparison of revenue requirement (nominal $)

9.4.2 Capital Expenditure Projections

Table 9-11 and Table 9-12 summarize the capital expenditures identified in the Status Quo and Preferred Plan, by category, for the Base Preferred Plan and Status Quo scenarios for Maui County, and are not broken out individually for Maui, Molokaʻi, and Lānaʻi.

Table 9-11. Capital Expenditures (Nominal $): Base Scenario—Maui County

('000)	2023–25	2026–30	2031–35	2036–40	2041–45	2046–50	Total
Distribution upgrades	$4,277	$0	$0	$0	$0	$0	$4,277
Transmission Interconnection	$0	$60,554	$106,638	$60,505	$144,392	$135,086	$507,175
Resilience [a]	$5,456	$10,425	$0	$0	$0	$0	$15,881
Grid mod phase 2 [a]	$2,999	$9,717	$0	$0	$0	$0	$12,716
Balance-of-utility business	$224,994	$249,223	$261,531	$288,751	$318,805	$351,986	$1,695,289
Total	$237,726	$329,918	$368,169	$349,256	$463,197	$487,072	$2,235,337

a. Final costs to be submitted in a forthcoming application.

Table 9-12. Capital Expenditures (Nominal $): Status Quo Scenario—Maui County

('000)	2023–25	2026–30	2031–35	2036–40	2041–45	2046–50	Total
Distribution upgrades	$4,277	$0	$0	$0	$0	$0	$4,277
Transmission interconnection	$0	$1,887	$22,462	$320	$68,090	$12,500	$105,259
Resilience [a]	$5,456	$10,425	$0	$0	$0	$0	$15,881
Grid mod phase 2 [a]	$2,999	$9,717	$0	$0	$0	$0	$12,716
Balance-of-utility business	$224,994	$249,223	$261,531	$288,751	$318,805	$351,986	$1,695,289
Total	$237,726	$271,251	$283,993	$289,071	$386,895	$364,486	$1,833,421

a. Final costs to be submitted in a forthcoming application.

9.4.3 Residential Customer Bill and Rate Impacts

As a result of an increasing revenue requirement in combination with increasing sales because of electrification, residential customer rates and bills are projected to remain relatively flat during the planning period in the Base Preferred Plan, demonstrating the benefits of electrification of the transportation sector.

Table 9-13 shows the average annual residential bill increases for Maui and Moloka‘i; however, the bill increases are smaller in the Base Preferred Plan scenario compared to the Status Quo scenario. The average annual bill decreases for Lāna‘i in the Base Preferred Plan scenario.

Table 9-13. Average Annual Residential Bill Increases

Average Annual Bill Increase (2023–2050)	Nominal $
Base scenario: Maui	0.43%
Status Quo scenario: Maui	2.16%
Base scenario: Moloka‘i	0.78%
Status Quo scenario: Moloka‘i	3.06%
Base scenario: Lāna‘i	(0.25)%
Status Quo scenario: Lāna‘i	0.25%

Figure 9-15 illustrates Maui’s residential customer bill impact in nominal dollars for a typical 500 kWh bill for the two scenarios.

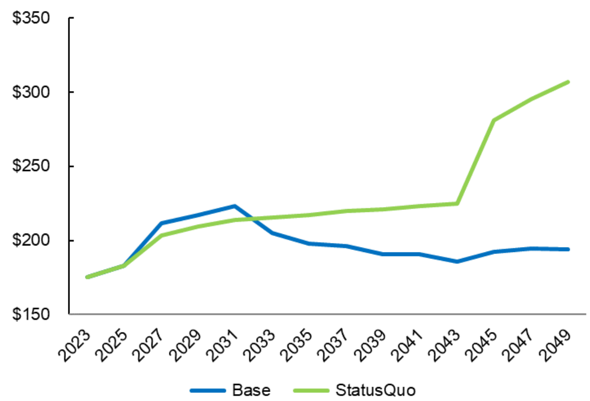


Figure 9-15. Maui: residential bill (nominal $)

Figure 9-16 illustrates Moloka‘i’s residential customer bill impact in nominal dollars for a typical 400 kWh bill for the two scenarios.

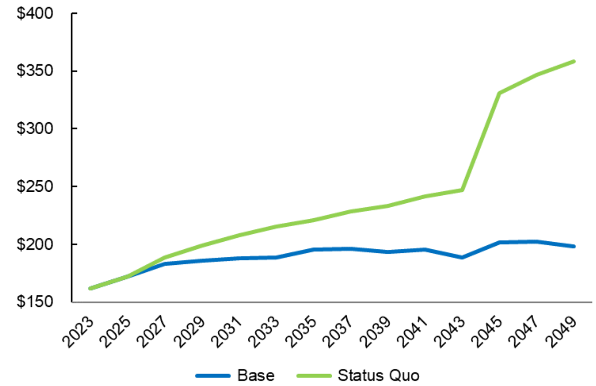


Figure 9-16. Moloka‘i: residential bill (nominal $)

Figure 9-17 illustrates Lāna‘i’s residential customer bill impact in nominal dollars for a typical 400 kWh bill for the two scenarios.

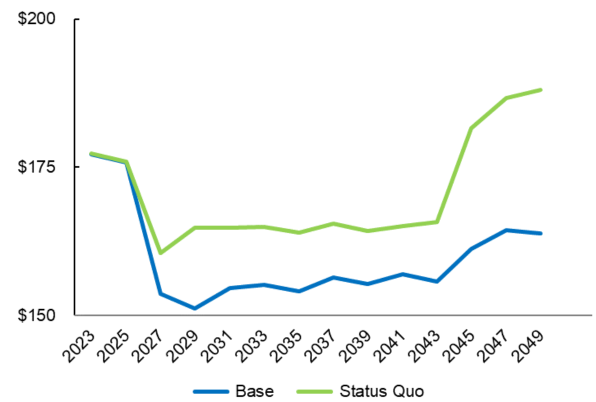


Figure 9-17. Lāna‘i: residential bill (nominal $)

Figure 9-18 illustrates Maui’s residential customer rates in nominal dollars for the two scenarios.

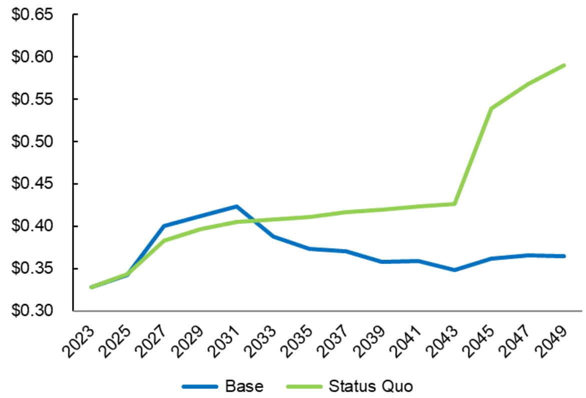


Figure 9-18. Maui: residential rates (nominal $)

Figure 9-19 illustrates Moloka'i's residential customer rates in nominal dollars for the two scenarios.

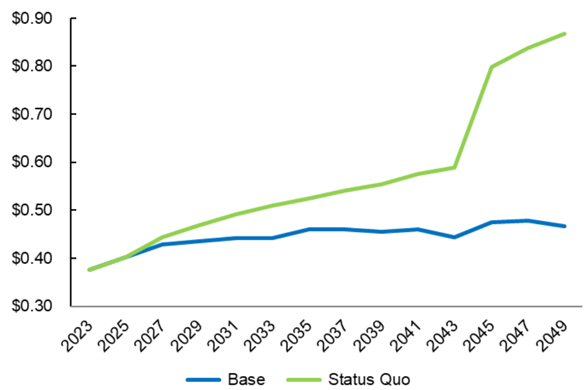


Figure 9-19. Moloka'i: residential rates (nominal $)

Figure 9-20 illustrates Lana'i's residential customer rates in nominal dollars for the scenarios.

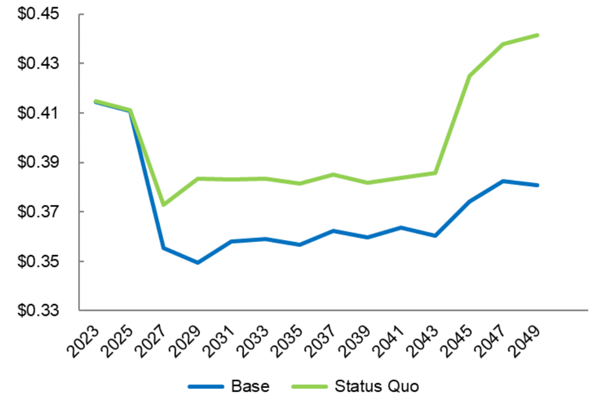


Figure 9-20. Lāna'i: residential rates (nominal $)

Figure 9-21 and Figure 9-22 illustrate the cost components to residential customer rates in nominal dollars for the Maui Base Preferred Plan and Status Quo, respectively. The ECRC component of residential rates makes up a larger portion of the total rate in the Status Quo compared to the Base Preferred Plan, and therefore has higher exposure to rate volatility because of fuel prices. In the Base Preferred Plan scenario, PPAC increases while ECRC declines because of the increase in fixed-cost PPAs for hybrid solar, wind, and energy storage, and less dependency on fuel-based generation and energy-based PPAs. The Base Preferred Plan scenario RBA component increases because of the investment needed in transmission and distribution infrastructure to enable renewables and electrification.

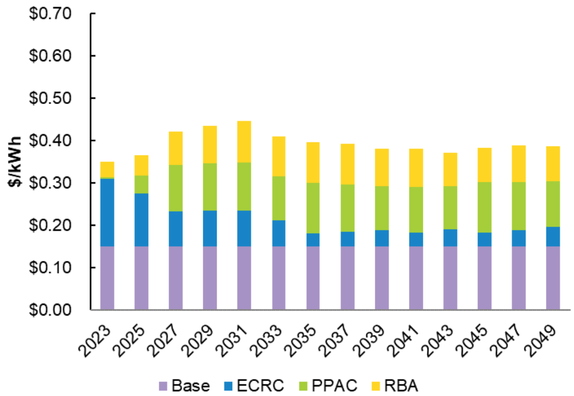


Figure 9-21. Maui: cost components to residential rates, Base scenario (nominal $)

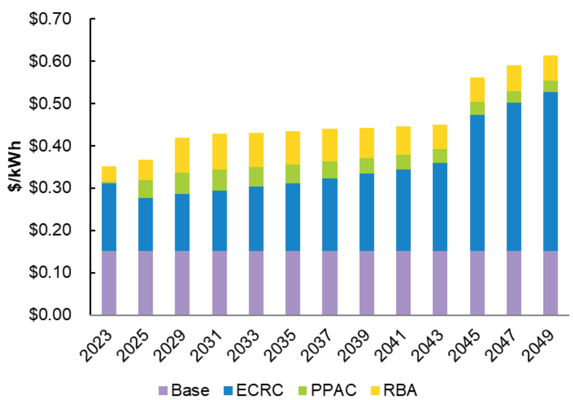


Figure 9-22. Maui: cost components to residential rates, Status Quo scenario (nominal $)

Figure 9-23 and Figure 9-24 illustrate the cost components to residential customer rates in nominal dollars for the Molokaʻi Base Preferred Plan and Status Quo, respectively. The ECRC component of residential rates makes up a larger portion of the total rate in the Status Quo compared to the Base Preferred Plan, and therefore has higher exposure to rate volatility because of fuel prices. In the Base Preferred Plan scenario, PPAC increases while ECRC significantly declines in 2031 as hybrid solar on a fixed-price PPA is added to the system and there is less dependency on fuel-based generation and energy-based PPAs. The Base Preferred Plan scenario RBA component increases because of the investment needed in distribution infrastructure to enable renewables and electrification.

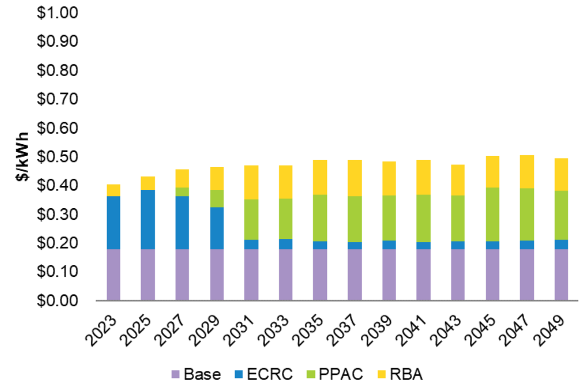


Figure 9-23. Molokaʻi: cost components to residential rates, Base scenario (nominal $)

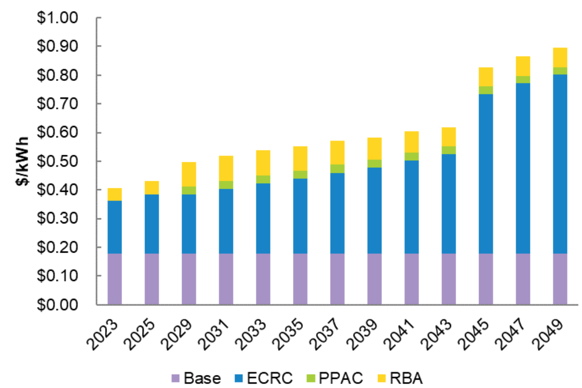


Figure 9-24. Molokaʻi: cost components to residential rates, Status Quo scenario (nominal $)

Figure 9-25 and Figure 9-26 illustrate the cost components to residential customer rates in nominal dollars for the Lānaʻi Base Preferred Plan and Status Quo, respectively. The ECRC component of residential rates makes up a larger portion of the total rate in the Status Quo compared to the Base Preferred Plan, and therefore has higher exposure to rate volatility because of fuel prices. In the Base Preferred Plan scenario, PPAC increases while ECRC significantly declines in 2027 as hybrid solar on a fixed-price PPA is added to the system and there is less dependency on fuel-based generation and energy-based PPAs. The Base Preferred Plan scenario RBA component is relatively flat as the

Base Preferred Plan did not require as much investment in distribution infrastructure compared to other islands.

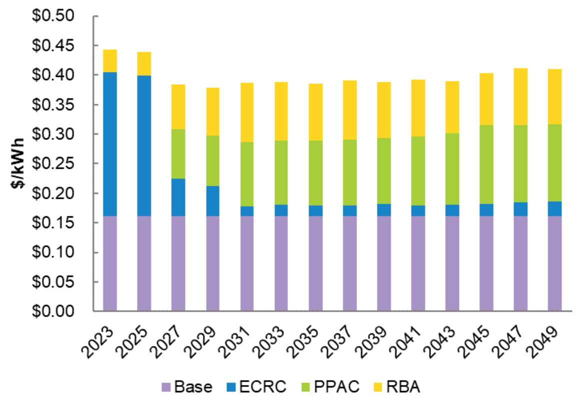


Figure 9-25. Lānaʻi: cost components to residential rates, Base scenario (nominal $)

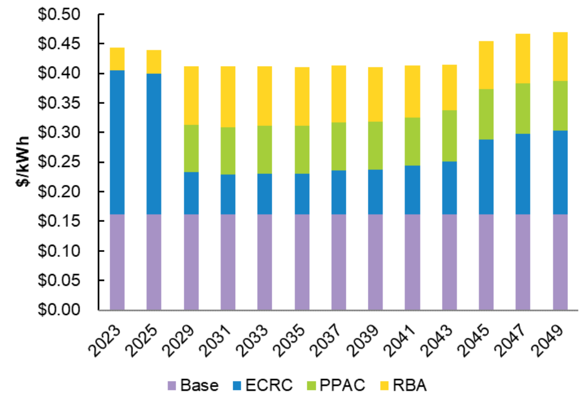


Figure 9-26. Lānaʻi: cost components to residential rates, Status Quo scenario (nominal $)

9.5 Emissions and Environmental

This section provides the forecast for future emissions that result from the Preferred Plans for each island and the estimated trajectory for meeting the decarbonization goals.

9.5.1 Greenhouse Gas Emissions

The renewable resources that are added in the Preferred Plans drive down emissions as fossil fuel–based generation is displaced by hybrid solar, wind, and offshore wind. By 2030, we expect to achieve a reduction in greenhouse gas emissions of 75%, relative to 2005 baseline levels. By 2045, some emissions are still produced by H-Power as a byproduct of its waste-to-energy process. Natural carbon sinks, or technologies that can capture carbon dioxide (CO_2) from the generator stack or extract it from the atmosphere, may need to be considered, holistically as a state, to achieve the State's net-zero decarbonization goal. Figure 9-27 summarizes the emissions in the Preferred Plans through 2050.

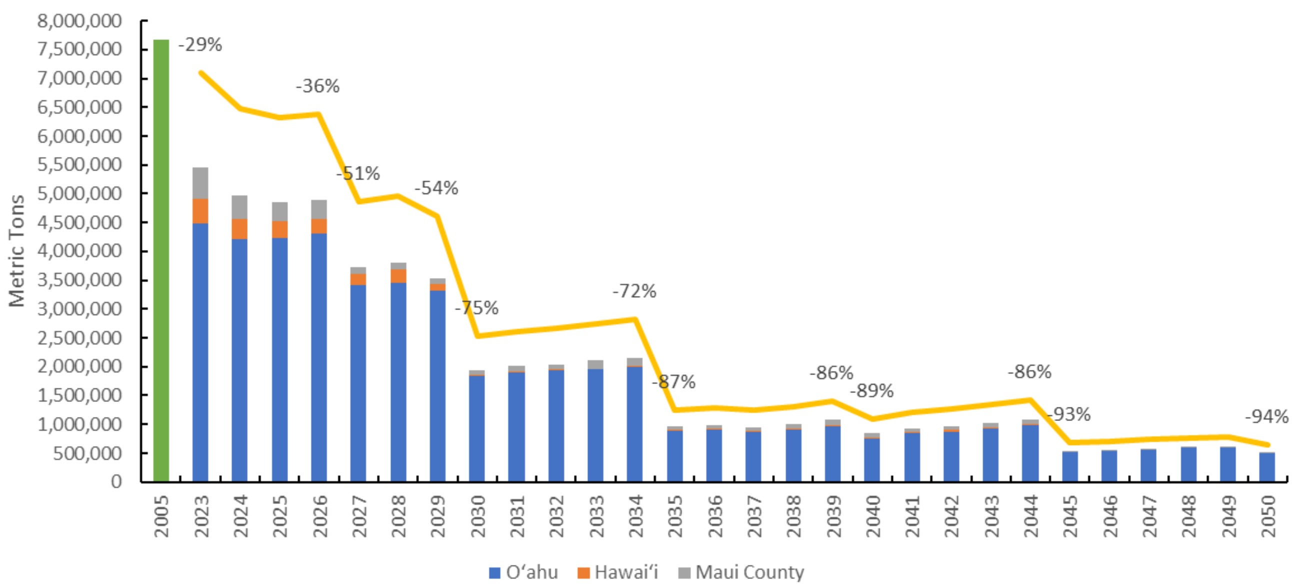


Figure 9-27. Consolidated emissions and percentage reduction compared to 2005 baseline without biogenic CO_2

The emissions for each island are provided below in Table 9-14.

Table 9-14. Preferred Plan Greenhouse Gas Emissions

Emissions (MT CO_2e)	2030	2035	2040	2045	2050
O'ahu	1,836,324	888,921	761,234	525,744	494,213
Hawai'i Island	13,987	14,218	17,325	3	8
Maui	84,672	56,921	58,906	31	26
Moloka'i	2,197	1,567	1,164	1	1
Lāna'i	2,072	2,031	1,694	1	1

Comparing the Base or Land-Constrained scenario to the Status Quo illustrates how effective the Base or Land-Constrained Preferred Plans are at reducing emissions compared to the Status Quo. The Base scenarios have less than half the emissions of the Status Quo by 2030, which enables the achievement of the 70% greenhouse gas reduction goal. However, the Land-Constrained scenario, with its more limited resource options, has mostly the same emissions as the Status Quo in the same year. Table 9-15, Table 9-16, Table 9-17, Table 9-18, and Table 9-19 provide the emissions in select years for O'ahu, Hawai'i Island, Maui, Moloka'i, and Lāna'i, respectively.

Table 9-15. O'ahu Greenhouse Gas Emissions Relative to Status Quo

O'ahu Emissions	2030	2035	2040	2045	2050
Base (MT CO_2e)	1,836,324	888,921	761,234	525,744	494,213
Land-Constrained (MT CO_2e)	3,359,238	1,756,826	1,741,284	798,996	644,545
Status Quo (MT CO_2e)	4,232,203	4,441,825	4,826,553	1,491,483	1,479,260
Base/Status Quo (%)	43%	20%	16%	35%	33%
Land-Constrained/Status Quo (%)	79%	40%	36%	54%	44%

Table 9-16. Hawai'i Island Greenhouse Gas Emissions Relative to Status Quo

Hawai'i Island Emissions	2030	2035	2040	2045	2050
Base (MT CO_2e)	13,987	14,218	17,325	3	8
Status Quo (MT CO_2e)	176,875	179,013	203,871	59	111
Base/Status Quo (%)	8%	8%	8%	5%	7%

Table 9-17. Maui Greenhouse Gas Emissions Relative to Status Quo

Maui Emissions	2030	2035	2040	2045	2050
Base (MT CO_2e)	84,672	56,921	58,906	31	26
Status Quo (MT CO_2e)	203,393	245,526	307,360	308	366
Base/Status Quo (%)	42%	23%	19%	10%	7%

Table 9-18. Moloka'i Greenhouse Gas Emissions Relative to Status Quo

Moloka'i Emissions	2030	2035	2040	2045	2050
Base (MT CO_2e)	2,197	1,567	1,164	1	1
Status Quo (MT CO_2e)	16,976	16,928	17,271	15	15
Base/Status Quo (%)	13%	9%	7%	4%	4%

Table 9-19. Lānaʻi Greenhouse Gas Emissions Relative to Status Quo

Lānaʻi Emissions	2030	2035	2040	2045	2050
Base (MT CO_2e)	2,072	2,031	1,694	1	1
Status Quo (MT CO_2e)	7,627	7,886	8,051	6	6
Base/Status Quo (%)	27%	26%	21%	17%	15%

9.5.2 Emissions Reductions due to Electrification of Transportation

As discussed earlier in this section, electrification of transportation can have positive financial benefits for customers. The adoption of electric vehicles will decrease the statewide emissions of greenhouse gases, furthering the State of Hawaiʻi's achievement of its decarbonization goals. In our Base scenario, electric vehicles forecast through 2050 will avoid significant amounts of fuel being consumed, shown in Figure 9-28, and emissions from burning that fuel, shown in Figure 9-29. While electric vehicles provide a meaningful reduction to statewide emissions, they will need to be charged from the grid, which will increase the demand for electricity and can increase the risk of having inadequate generation in the future, as discussed in Section 12.2.

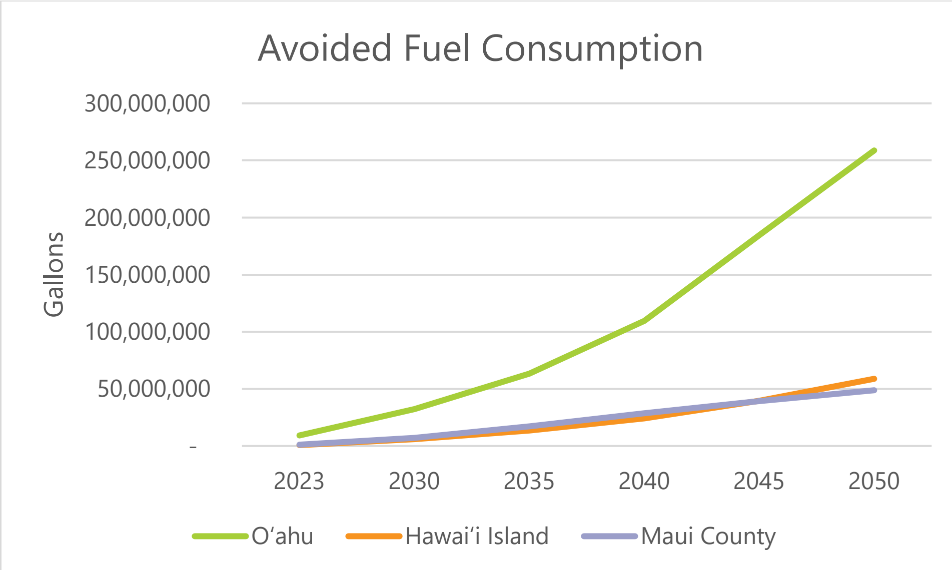


Figure 9-28. Avoided fuel consumption due to electric vehicle adoption

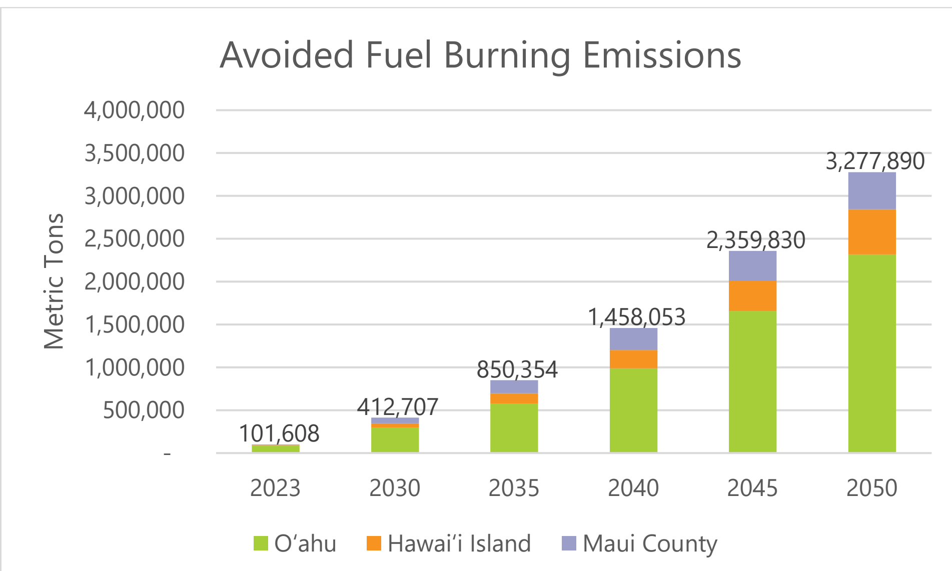


Figure 9-29. Avoided greenhouse gas emissions due to electric vehicle adoption

10. Energy Equity

In this section, we discuss our ongoing efforts to address energy inequities and offer solutions that we can implement and continue to learn from and expand in the future. As the cost of living in Hawaiʻi continues to rise, we must make electricity affordable and ensure that we ease the burden of the renewable transition on low- to moderate-income customers and communities that bear the burden of hosting energy infrastructure in the past and future. The transition increases access to renewable energy and equitability for all.

The Public Utilities Commission recently opened a proceeding to investigate energy equity in response to legislative resolutions. The areas for exploration include high energy rates in Hawaiʻi, high percentage of LMI persons, high energy burden, lack of universal access to renewable energy initiatives, need for utility payment assistance, historical siting of fossil-fuel infrastructure, land constraints, and regulatory process burdens.

Everyone has in an interest in an equitable energy system. As society continues to electrify all aspects of the economy, all customers stand to benefit if everyone is able to afford electricity and participate in the transition.

10.1 Equity Definitions

The Public Utilities Commission has defined the following key terms to guide equity discussions:

- **Equity** refers to achieved results where advantages and disadvantages are not distributed on the basis of social identities. Strategies that produce equity must be targeted to address the unequal needs, conditions, and positions of people and communities that are created by institutional and structural barriers.
- **Energy equity** refers to the goal of achieving equity in both the social and economic participation in the energy system, while also remediating social, economic, and health burdens on those historically harmed by the energy system.
- **Low- to moderate-income (LMI) persons** are those whose income is at or below 150% of the Hawaiʻi federal poverty limit.
- **Energy burden** is the percentage of a household's income spent to cover energy cost.

10.2 LMI Programs

We have recently selected CBRE projects (also known as the Shared Solar program) through a competitive procurement for LMI community-based solar projects. While we were required to award a minimum of one project each on Oʻahu, Maui, and Hawaiʻi Island, we awarded seven total projects as shown in Table 10-1, to provide greater access to renewable energy to LMI eligible customers. While these projects may not provide an opportunity to every LMI customer that desires to participate in the renewable transition, it represents a start that will enable us to improve on and expand programs and choices for customers in the future.

Table 10-1. Community-based Solar Projects for LMI Customers

Island	Developer	Project	Shared Solar Megawatt Capacity
O'ahu	Nexamp Solar & Melink Solar Development	Kaukonahua Solar	6 MWh (solar only)
Maui	Nexamp Solar	Lipoa Solar	3 MW + BESS
Maui	Nexamp Solar	Makawao Solar	2.5 MW + BESS
Maui	Nexamp Solar	Piiholo Road Solar	2.5 MW + BESS
Hawai'i Island	Nexamp Solar	Kalaoa Solar A	3 MW + BESS
Hawai'i Island	Nexamp Solar	Kalaoa Solar B	3 MW + BESS
Hawai'i Island	Nexamp Solar	Naalehu Solar	3 MW + BESS

The Shared Solar program embraces the concept of a community project by giving the surrounding community (i.e., census tract) first priority in subscribing to a Shared Solar project. We have also made verification of LMI eligibility easier for customers and require developers to dedicate 100% of the project to LMI eligible customers, reserving at least 60% of the project for residential LMI customers. Each project will have different offerings or subscription fees and arrangements. In exchange for subscribing to a project, LMI customers will receive a monthly bill credit to help reduce their energy costs.

10.3 Affordability and Energy Burden

Energy burden on LMI customers is one of the affordability metrics measured in the Performance-Based Regulation framework. The metric evaluates the typical and average annual bill for a residential customer as a percentage of a low-income household's average income (defined as 150% of the Hawai'i federal poverty level), by island. Using the electric bill and rate projections in Section 9, Figure 10-1 shows the projected affordability metric based on our Preferred Plans through 2050 for the typical residential customer on each island.

Our projections show that the transition to clean energy may reduce the overall energy burden for the typical residential customer on each island through 2050, compared to today's energy burden.

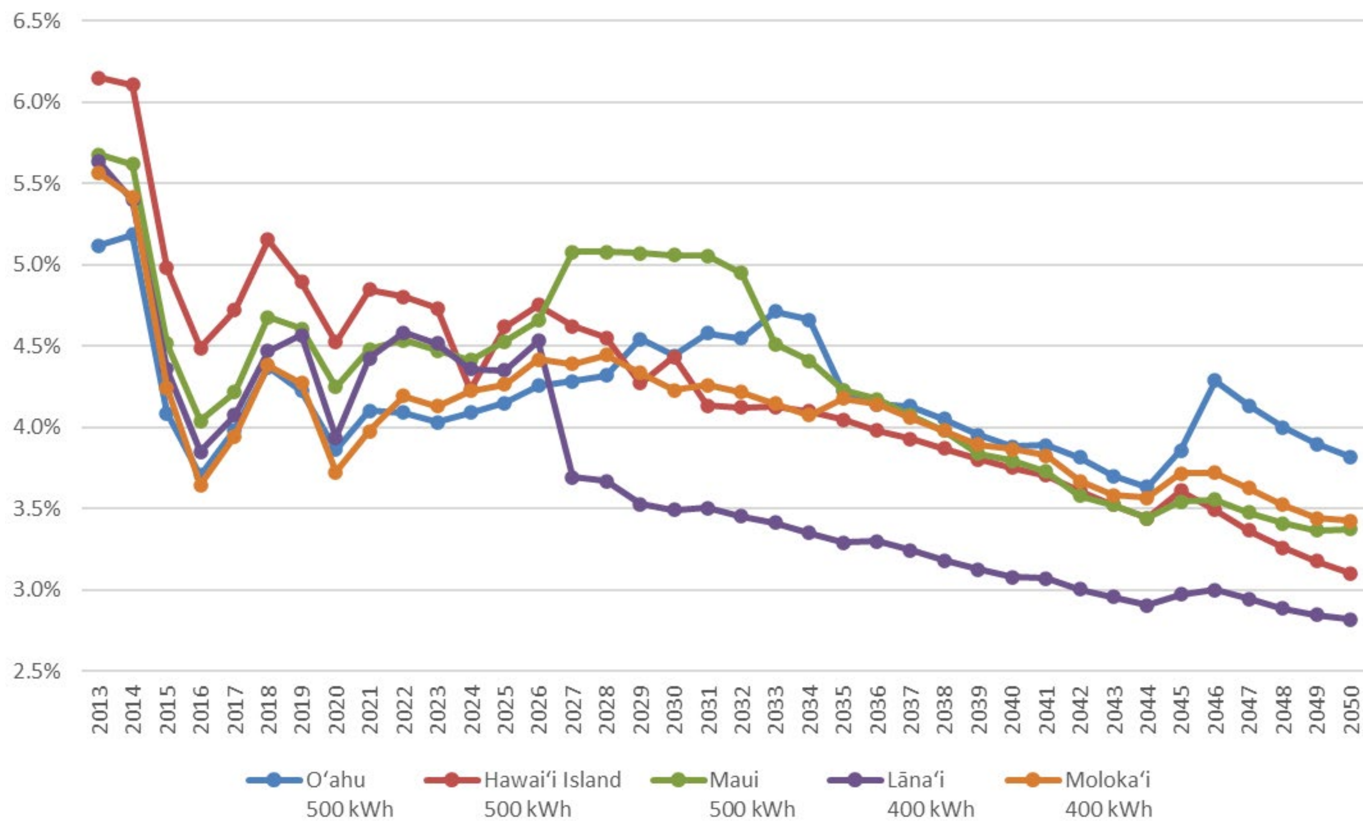


Figure 10-1. Typical residential bill as a percentage of low-income average income per island (150% of the federal poverty level)

10.4 Community Benefits Package for Grid-Scale Projects

Through various forums, we have heard the desire of communities to be more engaged early in the renewable energy project development process. We continue to engage communities around the islands as we develop RFPs and identify future grid needs. Building upon the outreach to stakeholders and communities in developing recent RFPs, we will continue to listen, learn, and work with communities throughout the process of developing the next round of procurements on each island we serve.

Based upon Stakeholder Council recommendations and past community feedback, we have expanded community engagement requirements for prospective project developers by specifying more detailed requirements and by adding a requirement for developers to provide a benefits package for the surrounding communities.

Our ongoing Stage 3 RFPs require project developers to commit to financial community benefits. Developers are required to provide at least $3,000 per MW (based on their proposed project size) per year in 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 our review. This document would 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, we 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 or industrial, land with greater impervious cover, or reclaimed land
- Procedural improvements made to further ensure the protection and preservation of cultural resources
- Prioritization of local labor and prevailing wage for proposed projects
- Additional requirements for developers to provide monthly updates to the community prior to and throughout the construction process

10.5 Renewable Energy Zone Development in Collaboration with Communities

The large-scale renewable project community benefits package is intended to address, in part, the burdens put onto communities that host clean energy projects and infrastructure. It does not mitigate all community concerns, nor does it recognize the future needs of the grid to achieve our decarbonization goals.

The most cost-effective path with current technology will require substantially more land to site clean energy projects along with transmission infrastructure. However, that cannot be accomplished without the acceptance of our communities. As the Stakeholder Council advised in discussing this topic, "we must go slow to go fast." Careful and thoughtful planning with our communities is needed to turn our vision into reality.

Stakeholder and public engagement have been a hallmark of this process. Last year we discussed more details of our Hawaiʻi Powered vision and focused community discussions on REZ development.

As we discuss in Section 4, we have provided multiple options, in-person and virtually, to provide input. The Hawaiʻi Powered website functions as a centralized hub for public engagement. In seeking this initial round of input on renewable energy zones, hawaiipowered.com/rez/ was made available to the general public. We also conducted in-person meetings, provided a newsletter describing the effort to numerous electronic mailing lists and community organizations, and ran a 3-week social media campaign. The online map includes the ability to drop a pin and add comments identifying those places that may be suitable as well as areas that are undesirable for development of renewable energy projects. The input gathered through this process will be used to refine the REZ analysis, which will guide planning efforts for transmission infrastructure needed to support future renewable resource development, as well as to inform developers regarding potential site suitability for specific renewable energy projects through the procurement process.

A complete list of comments received through our engagement through the Hawaiʻi Powered website is included in Appendix A, and a summary of common themes related to equity is listed below.

10.5.1 Oʻahu

- The Kahuku and West Oʻahu communities expressed, some strongly, that no windmills should be built. The Waialua community had similar sentiments, and also commented on the lack of support for offshore wind among the community.
- In general, communities across Oʻahu believed that wind turbines should not be allowed to be built near homes, schools, and farms. Wind turbine placement is controversial and should be discussed with communities.
- Renewable technology was raised often in terms of finding technology that requires less land space and has a smaller footprint. We also received suggestions to evaluate hydro or tidal, geothermal, and nuclear energy.
- Equity (as opposed to equality) was raised to ensure distribution of burden for hosting renewable projects.
- A desire was expressed to make sure that electricity generated in a community stays in that community. For example, Will Waiʻanae and North Shore side (which have high land

potential) be given higher-priority usage over Waikīkī (which is a high energy user)?

- Many commented that rooftop solar and parking lot solar canopies should be a priority before turning to land for grid-scale projects. This sentiment was a frequently shared comment on all islands.
- Affordability was a common theme; for example, one commenter said, "If you drive the cost of electricity so high that it becomes unsustainable, all effort toward clean energy will be useless. Yes, pursue clean energy options, but do it in a way that puts the burden on [Hawaiian Electric] and the State of Hawai'i, not on customers who are already stretched too thin paying energy bills."
- Affordability and access to energy options was another theme; for example, "As a renter, I feel left out of this process and at the whim of my landlord." And "100% renewable is not feasible and will cost more than you believe you will save. It is unattainable for the majority of people. You are placing a huge burden on the bottom of the income bracket."
- Many advocated for incentives and programs to participate in rooftop solar, such as community buy-back programs, grant programs (especially for lower-income residents), and subsidized re-roofing/re-paneling.
- Utilization of existing infrastructure was discussed, rather than conducting new development.
- Residents expressed a desired expansion of EV charging stations and plug types.

10.5.2 Maui

- A common theme we heard on Maui related to respect for cultural sites and preservation of Maui's natural beauty, such as Haleakala—though some expressed that you could respect the cultural sites while finding opportunities.
  - "Putting up turbines or solar in Central Maui wouldn't bother me, but beyond that should stay untouched."
  - "Ukumehame—the land has been decimated; maybe solar could be used but as long as it doesn't add to the negative effects already being seen in that area."
  - "Concern would be for Hana, lot of sensitivity there, don't recommend putting anything there."
  - The Waihe'e, Honua'ula, and Mauka areas also were raised as having cultural significance.
- Some community members mentioned opportunities for agricultural lands on Maui that are not farmable, which could be good possibilities for renewable projects, such as in central and west Maui.
- Adding solar panels to existing infrastructure was mentioned.
- Renewable technology was raised often in terms of finding technology that requires less land space and has a smaller footprint. We also received suggestions to evaluate hydro, tidal, and nuclear energy.
- Desired expansion of EV charging stations was expressed.

10.5.3 Hawai‘i

- Similar to O’ahu, Hawai’i Island community members want renewable projects sited away from the population so the project does not disrupt anyone.
  - “While I’m not in favor of wind energy, especially anywhere near populated areas, I believe solar panels should be placed on every single public building possible (schools, government buildings, etc.) and over parking lots (covered parking).”
- Concerns were expressed for threats to endangered species due to wind turbine blades:
  - “Renewable energy must not come at the expense of native habitat and species. Use previously developed land and areas that are already covered with non-permeable surfaces.”
- Similar to other islands, we received several comments regarding solar canopies to cover parking lots and more rooftop solar.
- Streamlining the process to participate in rooftop solar was mentioned.
- Desired expansion of EV charging stations was expressed.
- Renewable technology was raised often in terms of finding technology that requires less land space and has a smaller footprint. We also received suggestions to evaluate hydrothermal and geothermal energy generation.

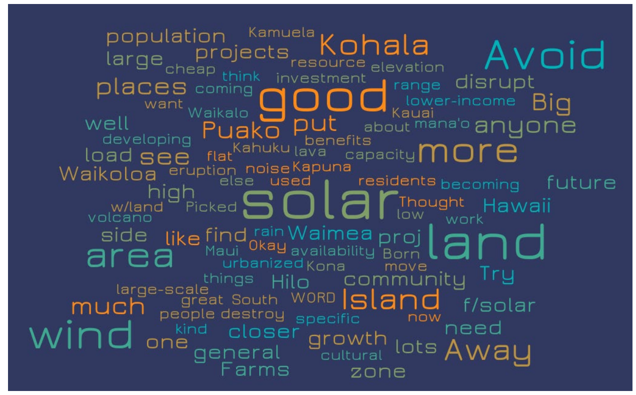


Figure 10-2. Keywords identified from the map comments

Figure 10-2 shows the keywords identified from the REZ map comments. Each island community has identified both opportunities and challenges, which provides insight into siting future additional large-scale projects.

The development of renewable energy zones will take time to conduct proper community engagement, permitting, and siting, among other tasks. Our immediate next step is to acquire information from landowners, through a request for information, who are willing to allow for renewable project development and marry those with the community comments we have received to date. Then we intend to work with specific communities on a renewable energy zone and transmission siting process to potentially develop these areas and to understand the opportunities and challenges.

10.6 Energy Transitions Initiative Partnership Project

We were selected last year as a partner in DOE's ETIPP to improve energy resilience and combat climate change. As part of the partnership, Hawaiian Electric is helping to identify areas on O'ahu that are optimal for developing microgrids to build a more resilient electric grid. Microgrids serve areas that are connected to the electric grid yet can be islanded during an outage to continue providing electricity through a variety of resources, including solar panels, a battery, and/or a backup generator.

We hope to reduce initial barriers and complexities with a map that takes into account the technical and practical viability of microgrid development. Microgrids are best suited to areas prone to prolonged outages during weather events, with clusters of customers and potential availability of renewable energy resources. The map would allow developers to contact potential microgrid participants and work with Hawaiian Electric to apply for the development of a specific microgrid.

Our objective of this effort is to provide customers with a map identifying areas that are good candidates for hosting hybrid microgrids, to improve electrical infrastructure to severe weather with consideration for electric grid layout, customer-sited resources, reliability, equity, among others.

There are several considerations in mapping potential microgrid locations like critical facilities and grid vulnerabilities, but we also explicitly take into account societal impacts such as disadvantaged communities and asset-limited, income-constrained residents, as shown in Figure 10-3.

1 CRITICALITY

Where are the critical loads, facilities and services?

- **Emergency**: emergency shelters, fire stations, EOC
- **Medical**: hospitals, out-patient facilities, surgical centers, skilled care facilities
- **Infrastructure**: water sources & treatment, internet exchange points, transmission towers, dams, bridges, ports, airports

2 VULNERABILITY

What parts of the grid currently and are projected to endure the longest or most frequent outages?

- **Natural hazards and inaccessibility**: flood, sea-level rise (through 2050), landslide, tsunami, remoteness
- **Outages** (2011-2021)

3 SOCIETAL IMPACT

What other locations would significantly impact communities if they lost power?

- Residential care facilities, community homes
- Schools, daycares, libraries
- ALICE program
- Disadvantaged communities

Figure 10-3. Description of the three criteria used to identify microgrid opportunities

Figure 10-4 below illustrates the critical facilities we have included in our initial analysis. As described in Appendix A we sought input from communities around O'ahu to acquire local knowledge to identify critical facilities and vulnerable or societal impact areas.

Included in analysis*

- Wastewater Treatment Plants
- Towers: AM and FM Transmission, Broadband, Cellular, Microwave, TV Analog and Digital Transmitter,
- Emergency Medical Stations
- Fire Stations
- Local, State Emergency Operations Centers
- National Shelter System Facilities
- Internet Exchange Points
- Ports
- Public Refrigerated Warehouses
- Local Law Enforcement Locations
- Hospitals
- Dialysis Centers
- Nursing Homes
- Urgent Care Facilities (ambulatory)
- Airports, Aircraft Landing Facilities

From Department of Homeland Security

Figure 10-4. Listing of the types of critical facilities included in the ETIPP analysis

Figure 10-5 and Figure 10-6 illustrate a microgrid map that can show the areas where criticality, vulnerability, and social impact intersect. These locations are prime locations for future microgrid development, which can also inform the hardening of distribution lines that would connect critical customers within that microgrid.

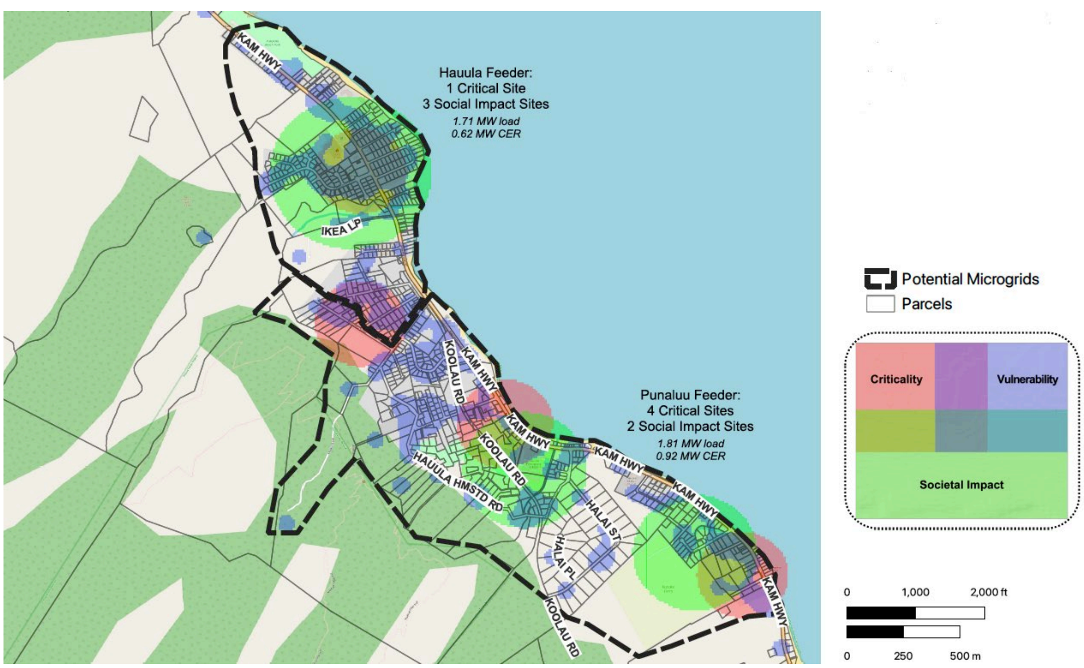


Figure 10-5. Hau'ula potential hybrid microgrids

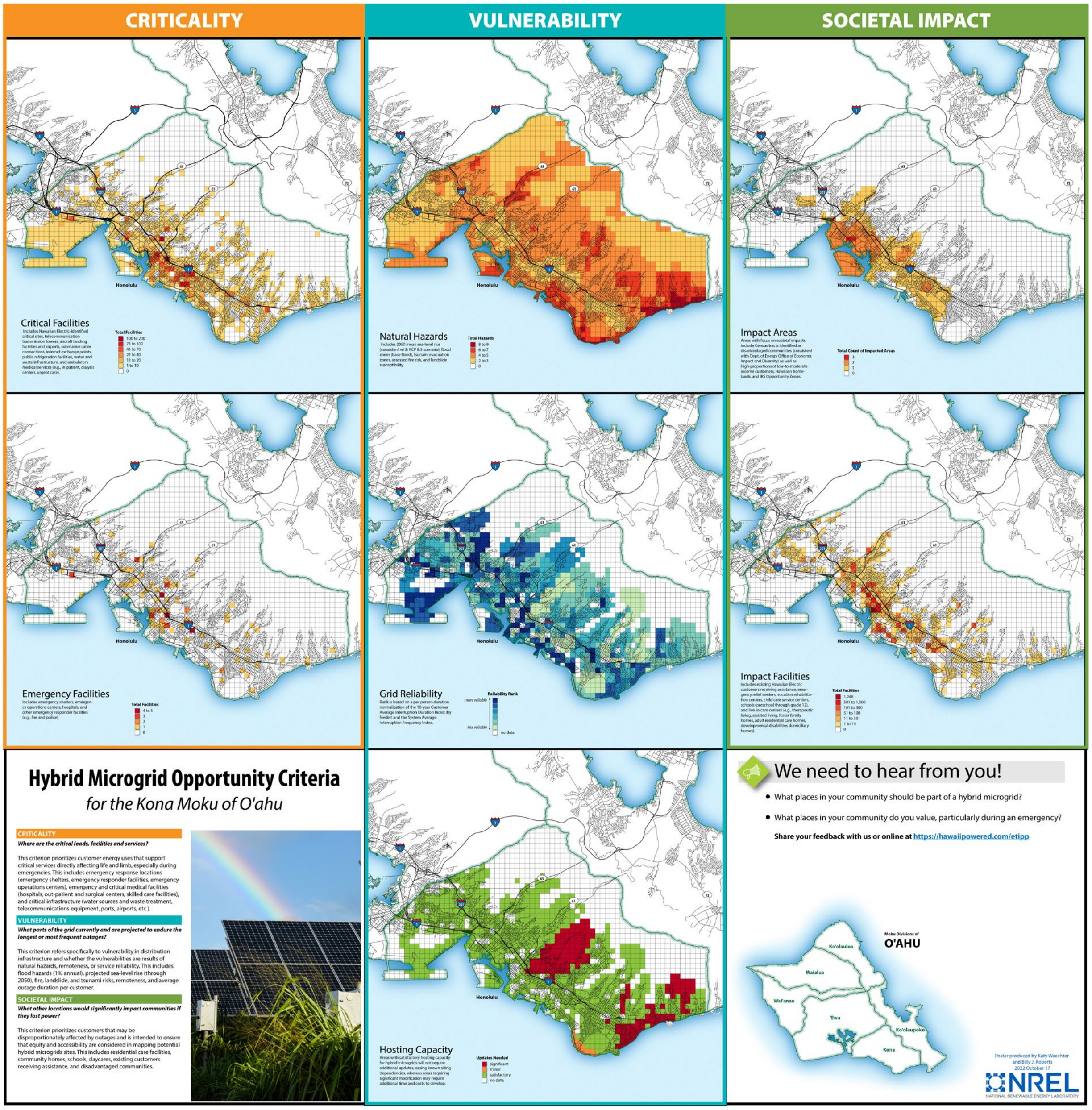


Figure 10-6. Map of the Kona Moku identifying locations for microgrid opportunity by criteria

Through these efforts we hope that more resilient energy can benefit our communities by highlighting areas with critical facilities that serve the greater public, vulnerable areas of the grid, and high social impact areas.

11. Growing the Energy Marketplace

We recognize that customers have choices in the way they use energy, which is why they must be at the center of the way we acquire solutions to the pathways we have laid out.

We want to create and grow a customer- and community-centered marketplace that can seamlessly and quickly deliver solutions to urgently address our climate goals and ease the burdens that fossil fuel has on our customers' bills, environment, and economy. Growing Hawai'i's energy marketplace consists of three main levers: pricing, programs, and procurements. It also allows customers and communities to participate in the process in several ways: by taking advantage of new time-of-use rates, and adopting customer technologies like energy efficiency, electric vehicles, or community solar projects. We also hope to give the community a voice in where and how large-scale projects are located and developed. The energy marketplace will deliver the actual technologies and solutions at the best price through competition.

We believe the energy marketplace, with communities and customers at the center, will deliver the best solutions, with urgency, and provide benefits to all customers. It also sets a framework for inclusive planning of the future grid, one that works for all.

As we describe in this section, we believe in the value that customers can deliver with new technologies, and we also believe that communities should benefit from hosting clean energy projects and infrastructure. Establishing the energy marketplace is a key pillar that will provide the predictability to participants and project partners need to take urgent action.

11.1 Customer Energy Resource Programs

The following sections describe the various mechanisms to grow the marketplace for customer resources and incentivize customer engagement to participate in the clean energy transition. These mechanisms include price signals aligned with system needs and programs with incentives to spur customer adoption of new technologies.

11.1.1 Pricing Mechanisms

We have installed advanced meters to more than 40% of our customers on O'ahu, Maui, and Hawai'i Island and expect to complete the rollout of advanced meters to all customers in our service territory by the end of the third quarter of 2024.

Advanced rate designs, which have been incorporated into our analysis, play an important role in the transition to a decarbonized electric system. Implementation of new time-of-use rates include three primary components: (1) customer charge, (2) grid access charge, and (3) time-of-use energy charges. The customer charge is applied as a fixed monthly charge for the cost of customer metering and billing. The grid access charge is a monthly charge for residential and small commercial customers and a charge based on measured demand for medium commercial customers for customer-related service connection costs. The third component, the time-of-use energy charge, is a $/kWh charge that consists of the cost of fuel, investments and operations of the grid and purchased power, and other surcharges, where the ratio of the daytime period (9 a.m. to 5 p.m.), overnight period (9 p.m. to 9 a.m.), and evening peak period (5 p.m. to 9 p.m.) rate is 1:2:3. Figure 11-1 below illustrates the proposed time-of-use energy charges for residential customers.

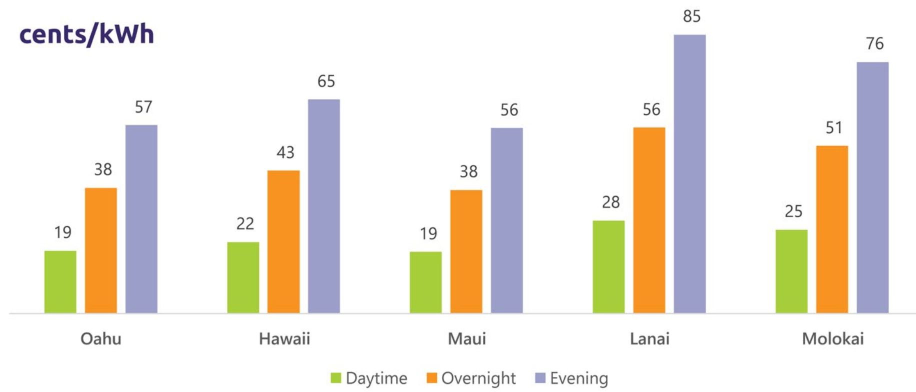


Figure 11-1. Time-of-use energy charges

The new rate structures are intended to encourage customer adoption of technologies such as energy efficiency and rooftop solar and energy storage, incentivizing energy conservation and behavioral changes to use energy away from times when the grid is most stressed (the highest-cost period). This includes ensuring that electric vehicles are not charged during the high demand period in the evening—as assumed in our grid needs analysis under managed vehicle charging. Because these new rates are a fundamental change from traditional electric rates, there will be a rollout period for the first year to a small sample of residential and small/medium commercial customers who have advanced meters to provide critical data and experience with these new rate structures and to determine whether the advanced rate design is working as intended. The next period will build on lessons learned to implement a broader rollout of advanced rate designs.

11.1.1.1 Electric Vehicle Pricing and Programs Mechanisms

We are committed to supporting decarbonization of the economy, and have established pricing and programs to encourage EV adoption. These pricing options and programs are another way in which we will grow the energy marketplace with our customers. These efforts include:

- EV public fast charging
- EV tariffs for electric buses and commercial customers
- eBus make-ready infrastructure pilot, or Charge Up eBus
- Charge Ready Hawai'i commercial make-ready infrastructure pilot or Charge Up Commercial

We have established pricing options for non-residential EV charging that are lower during the midday period from 9 a.m. to 5 p.m. daily to align with our system needs to encourage charging when renewable resources are abundant.

Since 2013 we have been providing EV public fast-charging stations for customers, and by the end of 2023 we plan to have 40 chargers installed across our service territory. We have proposed an expansion of this program and revised rates that are cost-competitive with gasoline. These fuel cost savings can help encourage greater EV adoption as it further improves the economics of owning an electric vehicle.

We have also established pricing options of tariffs for electric buses and commercial customers. The tariffs also provide significantly lower demand charges than the corresponding commercial rate schedules, Schedules J and P.

To complement the pricing options, our "Charge Up" programs are intended to reduce the upfront costs of installing charging infrastructure for bus operators, commercial customers, and EV service providers. Participants in these programs are required to use the EV time-of-use rates, which promotes charging during the daytime, but we have received feedback that this can be challenging for operational efficiencies of some participants.

11.1.2 Customer Programs Valuation

The "freeze" scenarios described in Section 6.8 can be leveraged to inform the potential value of achieving the forecasted adoption of a particular technology, similar to the work completed in the DER proceeding that led to the creation of the Battery Bonus program. Customer technologies not only provide choices for customers to control their energy bills, but they also remain critical to reducing the amount of large-scale resources (and land) that is needed to meet our goals. Additionally, we hope to create programs where not only customers benefit but the broader grid as well, and customers are equitably compensated for the services they deliver.

The EE, private rooftop solar, and EV charging adoption forecasts may be evaluated to determine potential value to inform program development that seeks to achieve the levels forecasted. The general framework for the freeze analysis is shown in Figure 11-2.

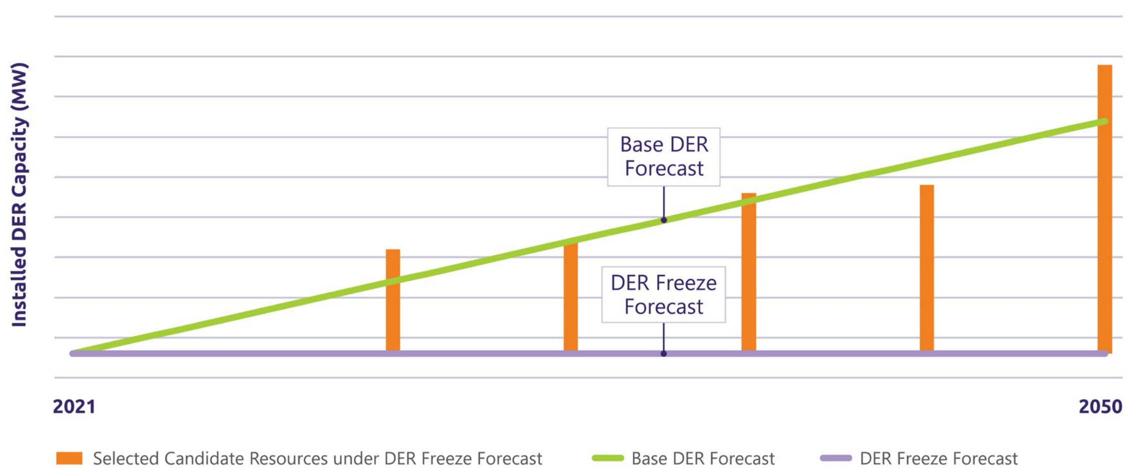


Figure 11-2. Illustration of values derived from freeze analysis

Determining the cost of the system without the forecasted adoption (i.e., frozen at current levels) compared to the cost of the system with the forecasted adoption effectively provides the approximate value of the addition of the customer energy resource. Using the DER Freeze as an example, when the distributed energy resources are frozen at current levels, additional resources will need to be built and selected by the models to replace the customer-sited resources assumed in the forecasted adoption. We can then determine the value of the customer technologies by evaluating the difference in cost between the Base scenario with the forecasted layer and DER Freeze, where the value is effectively avoiding the cost of those additional resources.

The performance characteristics of the resource (i.e., DER capabilities to provide grid services, EV charging profiles, EE supply bundles) are critical to appropriately valuing a program. From a system cost perspective, a program could be deemed cost-effective if the all-in cost of a program is less than the value determined in the freeze analysis. The design of the program should also reflect the performance requirements and services modeled. Any incentives allocated as part of the program should be performance-based to ensure that customers are receiving the commensurate benefits. The freeze analyses are intended to provide high-level guidance to inform more detailed discussions to create new programs or update current ones. The detailed design of programs may include other cost perspectives, aside from the system cost perspective as analyzed here, such as the rate impact to all customers, impact to customers participating in the programs, and impact to non-participating customers, to ensure that programs are being designed equitably.

The results of the Freeze scenarios shown in Table 11-1 indicate that there are cost savings if distributed energy resources (rooftop solar and battery energy storage) or energy efficiency is adopted as forecasted (except on Molokaʻi) and cost increases if electric vehicles are adopted as forecasted.

Table 11-1. Avoided Costs for the Freeze Scenarios, Relative to Base

NPV Avoided Cost (2018$, $MM)	DER Freeze	EV Freeze	Unmanaged EV	EE as a Resource
Oʻahu	580	-1,053	87	196
Hawaiʻi Island	150	-221	13	293
Maui	178	-37	37	72
Molokaʻi	3.7	-1.9	0.2	-1.5
Lānaʻi	1.3	-0.9	-0.1	0.5

Compared to unmanaged EV charging, managed charging does provide cost savings on all islands (except Lānaʻi) but not enough to offset the cost increases due to the overall higher demand from electric vehicles. The NPV avoided cost provides the break-even dollars that can inform incentives or total program costs to incentivize customers to adopt distributed energy resources or to allow the dispatch of their electric vehicles as a resource to serve grid needs.

11.1.2.1 O‘ahu

Figure 11-3 shows the resource capacity added for the Base, DER Freeze, EE Resource, EV Freeze, and Unmanaged EV scenarios, and Figure 11-4 shows the NPV of the Base, DER Freeze, EE Resource, EV Freeze, and Unmanaged EV scenarios. Cost is displayed in millions of 2018 dollars (2018$MM).

The following offers a summary of the valuation of customer resources that may be used to inform the design of future or current program updates:

- The DER Freeze scenario is similar to the Base scenario. Slightly more hybrid solar is selected in the DER Freeze scenario than in the Base scenario to compensate for the lower DER capacity.
  - More resources built results in an NPV that is approximately 7% higher than the Base scenario NPV.
- The EE as a Resource scenario selects the EE supply bundle, standalone solar, and renewable firm in addition to the renewable resources selected in the Base scenario. As shown in Section 11.1.3, the load impact of the EE supply curves is smaller than the EE load forecast. This results in more selected resources and higher generation need for the EE as a Resource scenario than for the Base scenario.
  - More resources built results in an NPV that is approximately 2% higher than the Base scenario NPV.
- The EV Freeze scenario selects fewer resources than the Base scenario, including no biomass resource. This highlights the growing load impact of electric vehicles, especially over time.
  - Fewer resources built results in an NPV that is approximately 12% lower than the Base scenario NPV.
  - The cost of electrification growth is partially offset by the savings from forecasted distributed energy resources and energy efficiency.
- The Unmanaged EV scenario is almost the same as the Base scenario with its managed EV forecast; however, more biomass is built.
  - The minimal NPV difference of 1% also implies little change between the Managed EV and Unmanaged EV scenarios.

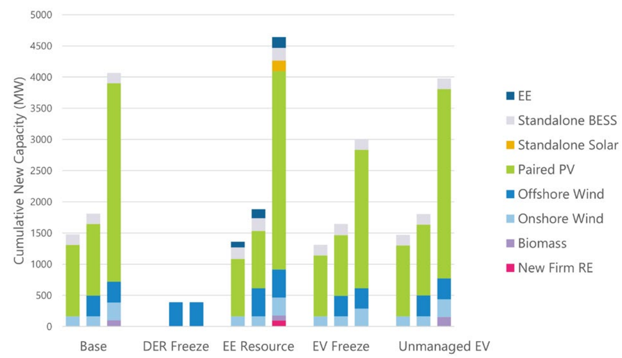


Figure 11-3. O‘ahu: cumulative new capacity selected by RESOLVE in 2030, 2035, and 2050 for the Base, DER Freeze, EE Supply Curve, EV Freeze, and Unmanaged EV scenarios

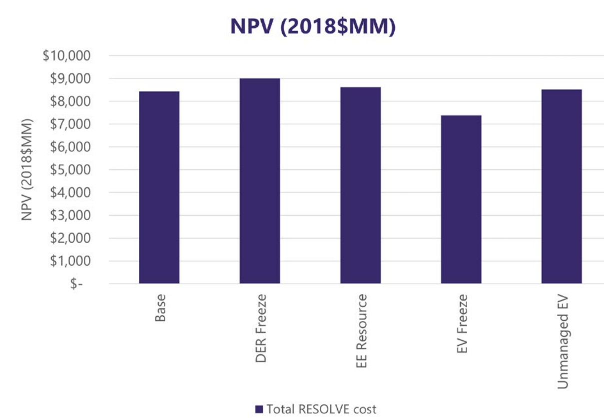


Figure 11-4. O‘ahu: NPV relative to the Base scenario for the DER Freeze, EE Supply Curve, EV Freeze, and Unmanaged EV scenarios

11.1.2.2Hawai'i Island

Figure 11-5 shows the resource capacity added for the Base, DER Freeze, EE Resource, EV Freeze, and Unmanaged EV scenarios, and Figure 11-6 shows the NPV of the Base, DER Freeze, EE Resource, EV Freeze, and Unmanaged EV scenarios. Cost is displayed in millions of 2018 dollars.

The following offers a summary of the valuation of customer resources that may be used to inform the design of future or current program updates:

- The DER Freeze scenario is similar to the Base scenario. More hybrid solar is selected in the DER Freeze scenario than in the Base scenario to compensate for the lower DER capacity.
  - More resources built results in an NPV 11% higher than the Base scenario NPV.
- The EE as a Resource scenario selects the EE resource, stand-alone solar, and renewable firm in addition to the renewable resources selected in the Base scenario. As shown in Section 11.1.3, the load impact of the EE supply curves is smaller than the EE load forecast. This results in more selected resources and a higher generation for the EE as a Resource scenario than for the Base scenario.
  - More resources built results in an NPV 22% higher than the Base scenario NPV.
- The EV Freeze scenario selects fewer resources than the Base scenario. This highlights the growing load impact of electric vehicles, especially over time.
  - Fewer resources built results in an NPV 17% lower than the Base scenario NPV with the added electrification loads.
  - The cost of electrification growth is partially offset by the savings from forecasted distributed energy resources and energy efficiency.
- The Unmanaged EV scenario is almost the same as the Base scenario with its managed EV forecast.
  - The 1% NPV increase also implies little change between the Managed EV and Unmanaged EV scenarios.

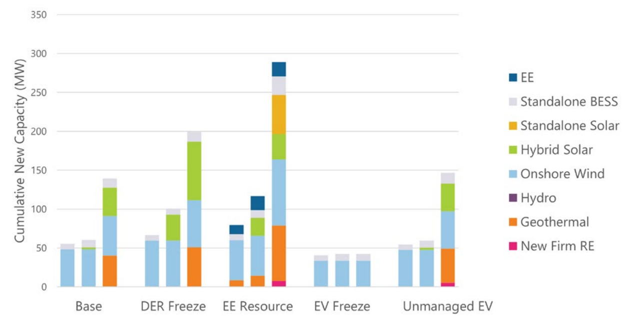


Figure 11-5. Hawai'i Island: cumulative new capacity selected by RESOLVE in 2030, 2035, and 2050 for the Base, DER Freeze, EE Supply Curve, EV Freeze, and Unmanaged EV scenarios

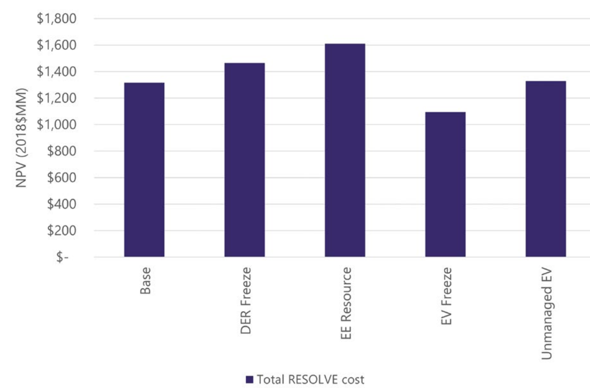


Figure 11-6. Hawai'i Island: NPV relative to the Base scenario for the DER Freeze, EE Supply Curve, EV Freeze, and Unmanaged EV scenarios

11.1.2.3Maui

Figure 11-7 shows the resource capacity added for the Base, DER Freeze, EE Resource, EV Freeze, and Unmanaged EV scenarios, and Figure 11-8 shows the NPV of the Base, DER Freeze, EE Resource, EV Freeze, and Unmanaged EV scenarios. Cost is displayed in millions of 2018 dollars.

The following offers a summary of the valuation of customer resources that may be used to inform the design of future or current program updates:

- The DER Freeze scenario is similar to the Base scenario. More hybrid solar is selected in the DER Freeze scenario than in the Base scenario to compensate for the lower DER capacity.
  - More resources built results in an NPV 8% higher than the Base scenario NPV.
- The EE as a Resource scenario selects the EE supply bundles in addition to the renewable resources selected in the Base scenario. As shown in Section 11.1.3, the load impact of the EE supply curves is larger than the EE load forecast. This results in more selected EE measures than the energy efficiency forecast in the Base scenario.
  - More resources built results in an NPV 3% higher than the Base scenario NPV.
- The EV Freeze scenario selects less hybrid solar and wind resources than the Base scenario. This highlights the growing load impact of electric vehicles, especially over time.
  - Fewer resources built results in an NPV 12% lower compared to the Base scenario with the added electrification loads.
  - The cost of electrification growth is partially offset by the savings from forecasted distributed energy resources and energy efficiency.
- The Unmanaged EV scenario is almost the same as the Base scenario with its managed EV forecast.
  - The minimal NPV difference of 2% also implies little change between the Managed EV and Unmanaged EV scenarios.

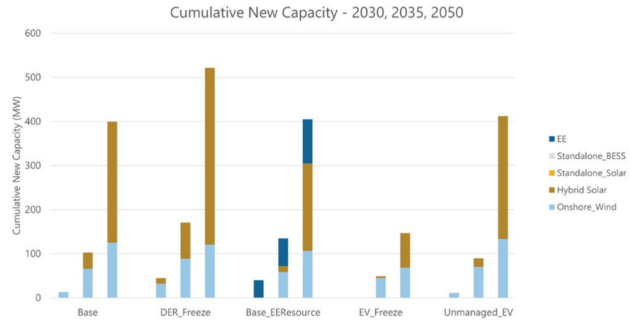


Figure 11-7. Maui: cumulative new capacity selected by RESOLVE in 2030, 2035, and 2050 for the Base, DER Freeze, EE Supply Curve, EV Freeze, and Unmanaged EV scenarios

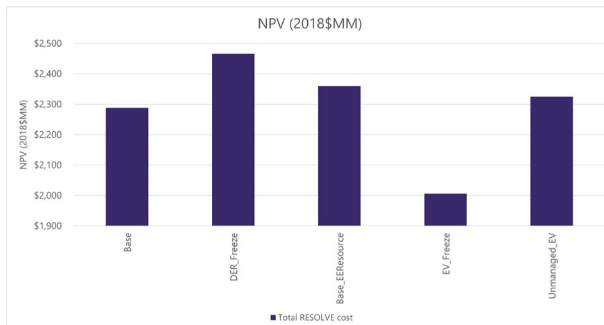


Figure 11-8. Maui: NPV relative to the Base scenario for the DER Freeze, EE Supply Curve, EV Freeze, and Unmanaged EV scenarios

11.1.2.4Moloka‘i

Figure 11-9 shows the resource capacity added for the Base, DER Freeze, EE Resource, EV Freeze, and Unmanaged EV scenarios, and Figure 11-10 shows the NPV of the Base, DER Freeze, EE Resource, EV Freeze, and Unmanaged EV scenarios. Cost is displayed in millions of 2018 dollars.

The following offers a summary of the valuation of customer resources that may be used to inform the design of future or current program updates:

- The DER Freeze scenario is similar to the Base scenario. Slightly more hybrid solar is selected in the DER Freeze scenario than in the Base scenario to compensate for the lower DER capacity.
  - More resources built results in an NPV that is approximately 6% higher than the Base scenario NPV.
- The EE as a Resource scenario selects the EE supply bundle in addition to the renewable resources selected in the Base scenario. As shown in Section 11.1.3, the load impact of the EE supply curves is greater than the EE load forecast. This results in slightly fewer selected resources and lower generation need for the EE as a Resource scenario than for the Base scenario.
  - Fewer resources built results in an NPV that is approximately 2% lower than the Base scenario NPV.
- The EV Freeze scenario selects fewer resources than the Base scenario. This highlights the growing load impact of electric vehicles, especially over time.
  - Fewer resources built results in an NPV that is approximately 3% lower than the Base scenario NPV.
  - The cost of electrification growth is partially offset by the savings from forecasted distributed energy resources and energy efficiency.
- The Unmanaged EV scenario is almost the same as the Base scenario with its managed EV forecast
  - The minimal NPV difference of close to 0% implies little change between the Managed EV and Unmanaged EV scenarios.

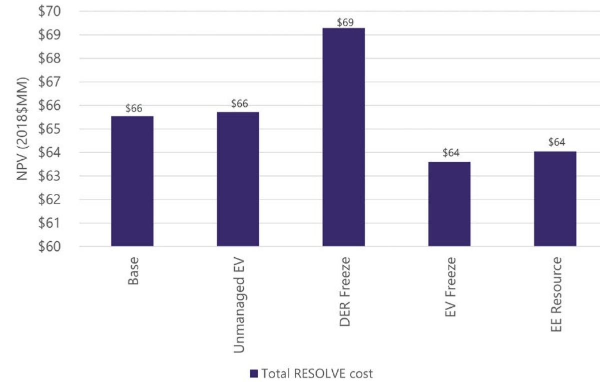


Figure 11-9. Moloka‘i: NPV relative to the Base scenario for the DER Freeze, EE Supply Curve, EV Freeze, and Unmanaged EV scenarios

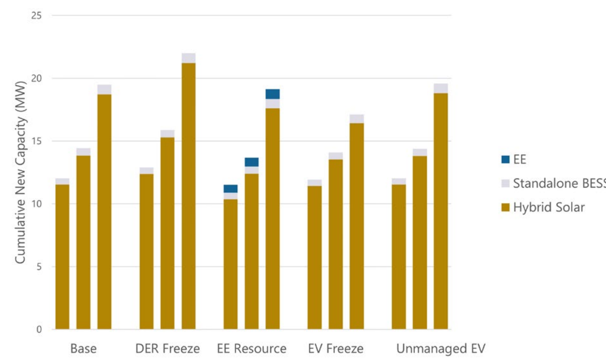


Figure 11-10. Moloka‘i: cumulative new capacity selected by RESOLVE in 2030, 2035, and 2050 for the Base, DER Freeze, EE Supply Curve, EV Freeze, and Unmanaged EV scenarios

11.1.2.5 Lānaʻi

Figure 11-11 shows the resource capacity added for the Base, DER Freeze, EE Resource, EV Freeze, and Unmanaged EV scenarios, and Figure 11-12 shows the NPV of the Base, DER Freeze, EE Resource, EV Freeze, and Unmanaged EV scenarios. Cost is displayed in millions of 2018 dollars.

The following offers a summary of the valuation of customer resources that may be used to inform the design of future or current program updates:

- The DER Freeze scenario is similar to the Base scenario. Slightly more hybrid solar is selected in the DER Freeze scenario than in the Base scenario to compensate for the lower DER capacity.
  - More resources built results in an NPV that is approximately 2% higher than the Base scenario NPV.
- The EE as a Resource scenario selects the EE supply bundle and standalone solar in addition to the renewable resources selected in the Base scenario. As shown in Section 11.1.3, the load impact of the EE supply curves is greater than the EE load forecast. Despite this, by 2050, there's slightly more selected resources and higher generation need for the EE as a Resource scenario than for the Base scenario.
  - More resources built results in an NPV that is approximately 1% higher than the Base scenario NPV.
- The EV Freeze scenario selects fewer resources than the Base scenario. This highlights the growing load impact of electric vehicles, especially over time.
  - Fewer resources built results in an NPV that is approximately 1% lower than the Base scenario NPV.
  - The cost of electrification growth is offset by the savings from forecasted distributed energy resources and energy efficiency.
- The Unmanaged EV scenario is almost the same as the Base scenario with its managed EV forecast.
  - The minimal NPV difference of close to 0% implies little change between the Managed EV and Unmanaged EV scenarios.

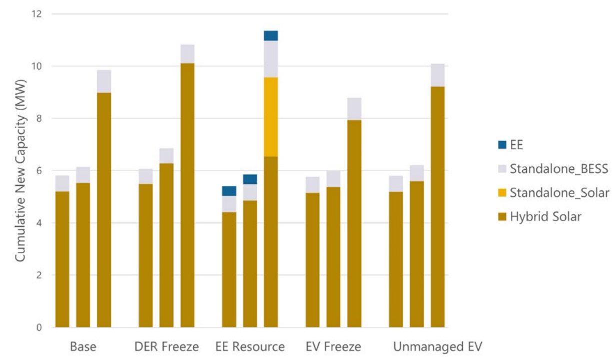


Figure 11-11. Lānaʻi: cumulative new capacity selected by RESOLVE in 2030, 2035, and 2050 for the Base, DER Freeze, EE Supply Curve, EV Freeze, and Unmanaged EV scenarios

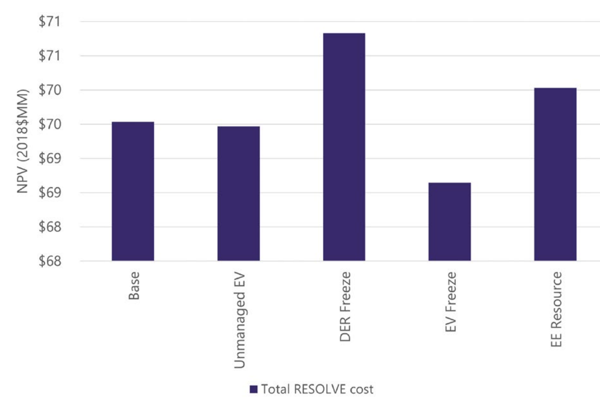


Figure 11-12. Lānaʻi: NPV relative to the Base scenario for the DER Freeze, EE Supply Curve, EV Freeze, and Unmanaged EV scenarios

11.1.3 Energy Efficiency as a Resource

Evaluating energy efficiency as a selectable resource can help to identify the shapes and costs of cost-effective EE measures as well as validate the sets of measures that were screened for cost-effectiveness in the market potential study.

In the supply curve bundling using the market potential study results, the majority of measures were screened to be highly cost-effective in the "A" grouping and flatter "Other" measures provided a significant portion of the energy savings in the Achievable Technical potential. Their selection in the RESOLVE modeling validates the benefit-cost testing in the market potential study, that energy efficiency can be a cost-effective resource alongside other supply-side resources and that peak focused measures are not necessarily desired more than flatter measures.

Across all islands, the same measures that were screened to be cost-effective in the market potential study with benefit-cost ratios greater than 1 were also selected by RESOLVE. On O'ahu and Hawai'i Island, the flatter "Other" bundles were preferred and less energy efficiency was selected than in the Base forecast. On Maui and Moloka'i, "Other" and "Peak" bundles were preferred with more energy efficiency selected than in the forecast. On Lāna'i, only the "Other" bundles were selected with the selected energy efficiency exceeding the forecast.

The model's preference for the "Other" shape mimics a baseloaded firm unit. While the "Peak" shape was also selected on some islands, the "Other" shape was selected in greater quantities, indicating that reducing system costs in all hours is more cost-effective than targeting just the peak hours.

Although the model did not select the exact same amount of energy efficiency as assumed in the Base forecast, the Base forecast provides a reasonable target for energy efficiency to be procured through a grid services type of competitive procurement because other resource, transmission, and distribution needs were based on achieving at least the energy efficiency level forecasted in the Base scenario. The procurement can provide a market test for the cost and performance of energy efficiency and an opportunity to evaluate specific EE proposals rather than the aggregated supply curves considered here. Additionally, more energy efficiency would contribute toward meeting our carbon reduction goals and could reduce land requirements for large-scale resources.

11.1.3.1O‘ahu

In the O‘ahu Base forecast, RESOLVE selected the “Other A” bundle, and no Peak bundles were selected. Additionally, as shown in Figure 11-13, combined energy efficiency because of codes and standards and the selected “Other A” bundle is less than the base EE forecast for most hours of the day, especially during the evening.

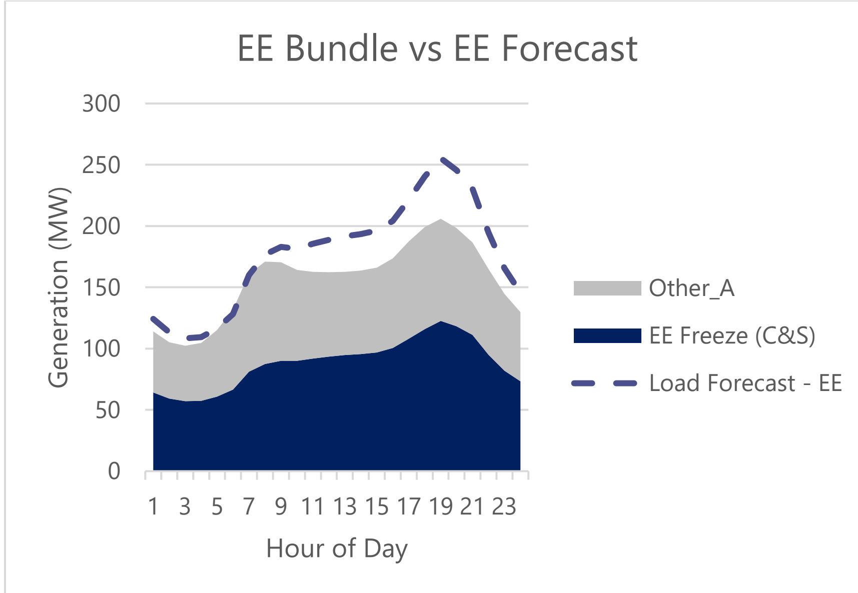


Figure 11-13. O‘ahu: EE Base forecast layer vs. EE RESOLVE selected resources, 2030

11.1.3.2Hawai‘i Island

In the Hawai‘i Island Base forecast, RESOLVE selected the “Other A” and “Other B” bundles, and no “Peak” bundles were selected. Additionally, as shown in Figure 11-14, combined energy efficiency because of codes and standards and the selected bundles is less than the Base EE forecast for most hours of the day, especially during the evening.

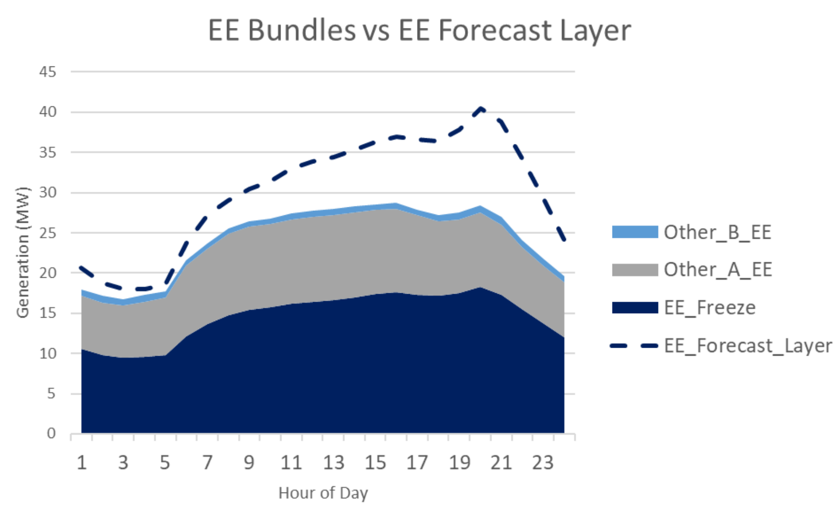


Figure 11-14. Hawai‘i Island: EE Base forecast layer vs. EE RESOLVE selected resources, 2030

11.1.3.3Maui

In the Maui Base forecast, RESOLVE selected the "Peak A," "Peak B," "Other A," and "Other B" bundles. As shown in Figure 11-15, the amount of EE bundles selected were greater than the base EE forecast for all hours of the day. This indicates that more energy efficiency than forecasted on Maui would be cost-effective for the system.

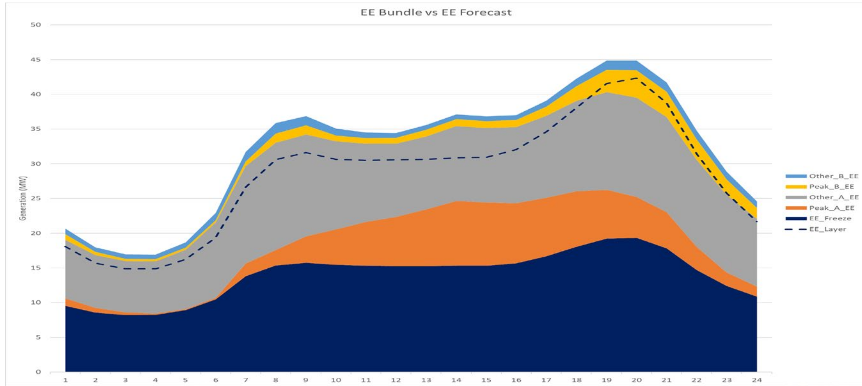


Figure 11-15. Maui: EE Base forecast layer vs. EE RESOLVE selected resources, 2030

11.1.3.4Moloka'i

In the Moloka'i Base forecast, RESOLVE selected the "Peak B," "Other A," and "Other B" bundles. As shown in Figure 11-16, the amount of EE bundles selected were greater than the Base EE forecast for all hours of the day. This indicates that more energy efficiency than forecasted on Moloka'i would be cost-effective for the system.

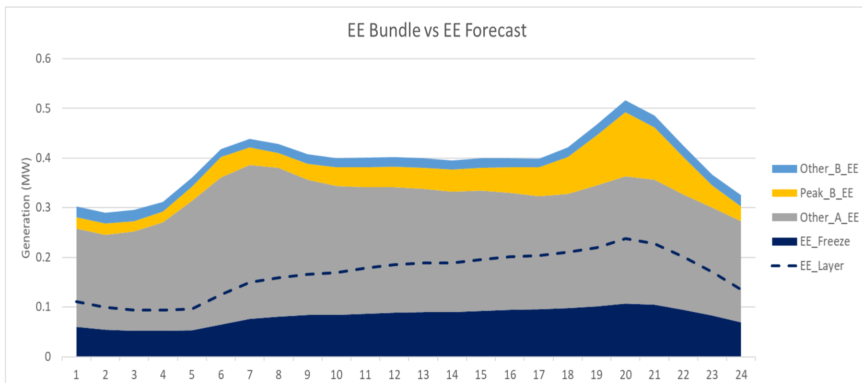


Figure 11-16. Moloka'i: EE Base forecast layer vs. EE RESOLVE selected resources, 2030

11.1.3.5Lāna'i

In the Lāna'i Base forecast, RESOLVE selected the "Other A" and "Other B" bundles. As shown in Figure 11-17, the amount of EE bundles selected were greater than the Base EE forecast for all hours of the day. This indicates that more energy efficiency than forecasted on Moloka'i would be cost-effective for the system.

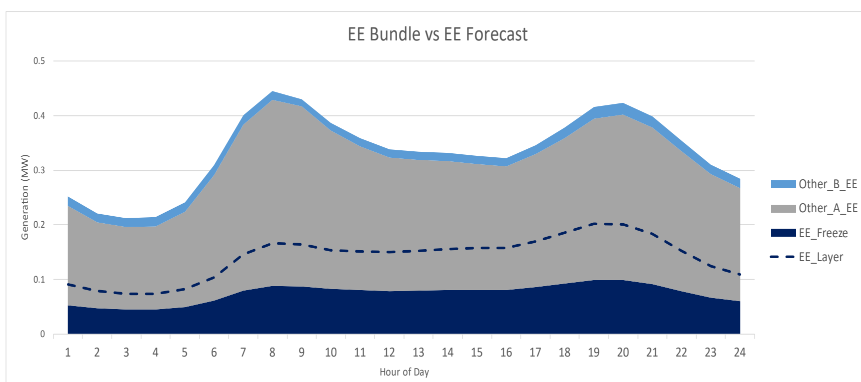


Figure 11-17. Lāna'i: EE Base forecast layer vs. EE RESOLVE selected resources, 2030

11.2 Procurement Plan

The following sections describe our plans to competitively procure resources aligned with the needs identified in this report. Competitive procurements are governed by the Framework for Competitive Bidding to ensure a fair process, which allows us to seek solutions from the market at the best prices for our customers.

11.2.1 Process

With the preferred resource plans on each island identified, the resource, transmission, and distribution needs will inform various RFPs (or other mechanisms like requests for information or expressions of interest) to seek competitive solutions from the market.

The novelty of Integrated Grid Planning is the seamless integration between planning and sourcing solutions from the energy marketplace. We envision that procurements for various needs are warranted and, as described in this section, we plan to procure large-scale resources, NWAs, and grid services. There are specific locational benefits as identified in the transmission and distribution needs analysis that may also be integrated into the various RFPs.

The Framework for Competitive Bidding, included in Appendix G, which was put forth by the competitive procurement working group and approved by the Public Utilities Commission for use in the Integrated Grid Planning process, was modified to reflect the current planning environment that has evolved in the 14 or more years since the initial framework was created.

The revised Framework for Competitive Bidding considered a few key areas:

- **Grid needs and system resources.** We updated the framework to describe the steps and process broadly to allow for more flexibility to meet grid needs to reflect the current market environment, such as new resource technologies and NWAs.
- **Long-term RFP.** While no specific updates were made for projects that require longer development time (i.e., 8–12 years), the Working Group believed that the updated framework provides sufficient flexibility to issue procurements of this type.
- **Interconnection and procurement scoping.** This is an area that the Working Group agreed could be pursued outside the framework and, therefore, no modifications were made. However, we have been working with stakeholders to improve and streamline the interconnection process and have been doing so through the recent CBRE and Stage 3 procurements as well as through the Performance-Based Regulation proceeding.

Finally, to grow the energy market as intended, we envision routine procurements to urgently address the needs as discussed throughout this report. We have a long way to go to reach our goals with time running short; to that end these Integrated Grid Plans serve as living roadmaps that provide sufficient guidance to acquire solutions to meet our goals. Similar to the progress we have made through Stage 1, 2, and 3 procurements over the past several years, we expect to continue competitive procurements on a routine basis for the years ahead.

11.2.2 Large-scale Competitive Procurements

Competitive procurements are a key way to ensure that we acquire the lowest-cost, best-fit resources for customers to address affordability.

Additionally, consistent with State policy, and in its Inclinations, the Public Utilities Commission stated its intent to pursue a balanced portfolio of energy resources:

> There is clear evidence that pursuing a diverse portfolio of renewable energy resources provides the best long-term strategy to maximize the use or renewables to achieve public policy goals. Project development and system integration costs may rise as higher levels of renewable resources are added to each grid and higher levels of any single energy resource will increase the challenge of adding new projects. Furthermore, as communities with the most abundant indigenous renewable resource are increasingly asked to host energy infrastructure, these communities are understandably concerned with the impacts of these projects and have voiced their opposition in several instances. For these reasons, the Commission supports a balanced and diverse portfolio of energy resources as the best long-term strategy to achieve the state's energy goals.

The challenges identified in the Inclinations have come into sharper focus in recent years. Communities are understandably concerned with the use of land and hosting projects in their neighborhoods. As discussed in this report, community engagement is central to the energy system transformation. A balanced portfolio of resources will ultimately increase reliability and resilience, introduce geographic diversity, and allow for sustainable uses of land.

Through our community engagement efforts and analysis to evaluate renewable energy zones, we are also considering different options to identify communities we can collaborate with to develop renewable energy zones to site future renewable projects. Pre-selecting locations or areas for renewable projects as part of the RFP has potential benefits, including to engage with communities early, plan and build infrastructure needed to enable or expand transmission capacity, and streamline the procurement process.

We also prefer competitive procurements to specify attributes, services, and capabilities required rather than specific technologies. However, recent all-source procurements through the Stage 1 and Stage 2 RFPs have led to the acquisition of exclusively solar paired with 4-hour energy storage and standalone energy storage resources. As described in Section 12.3, as the quantity of solar and storage increases, the value of solar and storage diminishes in their ability to fully replace the firm capacity resources that are expected to be retired over the next decade. To address reliability and resource diversity, a range of technology options should be considered, including variable and firm generation, fuel flexibility, renewable fuels, long-duration storage, offshore resources, and pump storage hydro, among others. These types of projects may take longer to develop than solar and storage projects. In some instances, it may be prudent to specify technologies consistent with the Integrated Grid Plan to send market signals that certain types of attributes are needed to fulfill certain grid needs.

11.2.3 Long-term RFP

To facilitate enabling resource diversity we believe issuing an RFP that allows projects that have longer development times (such as pump storage hydro, offshore wind, geothermal, and projects that require transmission infrastructure) to submit proposals is the prudent course of action. These are the types of resources and technologies that have either been suggested by communities and stakeholders or selected in the capacity expansion modeling. The long-term RFP concept is supported by intervenors in the Integrated Grid Planning proceeding. Progression Hawai'i stated, in response to our first review point, that it supports a "long-term RFP concept as a pathway to integrate other technologies into the resource portfolio other than solar and storage that will enhance the reliability and resilience of the system through resource diversification" (March 4 Reply Comments at 54). Progression Hawai'i further recommended that the solicitation allow commercial operations out to 2035 (June Reply Comments at 5).

In preparation for the long-term RFP, we issued an expression of interest for multi-day energy storage in April 2022, and for projects that require a longer development time frame in July 2022. We received several responses and we discussed the results of the expression of interest at the Stakeholder Technical Working Group meeting in February 2023. In that meeting, we discussed what changes to the RFP process would need to occur to facilitate the inclusion of long-term resources into the first round of Integrated Grid Plan procurements.

We identified numerous RFP terms that would require modification if long-term resources were to be included in the same solicitation as more near-term resources. First, both developers and Hawaiian Electric recognized the challenges of providing and holding to firm pricing for resources that could be years longer away from commercial operation than the projects currently procured. This challenge further impacts the ability to effectively evaluate near-term and long-term resources if the pricing for long-term resources could change. Other examples of modifications that will likely be necessary include the requirements for certain actions at the time of bid submission, such as site control, and model submission. In addition, the overall RFP schedule will likely require modification, and contract terms will also need to be developed to contemplate the longer period between contract execution and commercial operations.

Given the necessary differences identified, it is likely that a separate RFP for long-term resources will be needed. An RFP with terms that contemplate the longer development cycle can be better tailored to the uncertainty surrounding bids with significantly later in-service dates. The idea would be to issue both the near-term and long-term procurements in the same time frame.

In the development of the long-term RFP, the Public Utilities Commission also instructed Hawaiian Electric to assess the "feasibility of using existing power plant sites to locate new, quick-start, fuel-efficient, flexible generation, to leverage existing site transmission and fuel supply infrastructure capacity that would be freed-up by retirements of existing generating units" (Order 32053 at 93). While the long-term RFP has not yet been drafted, we will look to further explore this possibility.

Pursuant to the Public Utilities Commission's guidance, we are also exploring if other company-owned sites could be made available for interconnection of a variety of technologies in our RFPs, and further seeking ways to streamline the interconnection process.

11.2.4 Bid Evaluation

Consistent with the approved Framework for Competitive Bidding and the process employed in the Stage 1, Stage 2, and Stage 3 RFPs, the Integrated Grid Plan RFPs will continue to employ a multi-step evaluation process. Once the proposals are received, they will be subject to a consistent and defined review, evaluation, and selection process. We review each proposal submission to determine if it meets the Eligibility Requirements and Threshold Requirements. Proposals that have successfully met these requirements will then enter a two-phase process for proposal evaluation, which includes the Initial Evaluation resulting in the development of a Priority List, followed by the opportunity for Priority List proposals to provide Best and Final Offers, and then a Detailed Evaluation process to arrive at a Final Award Group.

The Initial Evaluation consists of two parts: a price evaluation and a non-price evaluation. The price and non-price evaluations result in a relative ranking and scoring of all eligible proposals. In the Stage 3 RFP, 11 non-price criteria range from community outreach to experience and qualifications, to financial strength and financing plan. While the criteria for the Integrated Grid Planning RFP have yet to be developed, they will largely be similar to what has been included in previous RFPs.

11.2.5 NWA Competitive Procurement

For the favorable NWA opportunities to address distribution grid needs identified in the distribution planning process, we will first seek Expression of Interest (EOI) from developers and aggregators who are capable of developing grid-scale renewable projects or aggregating distributed energy resources/energy efficiency in locations that will help reduce loading on circuits and transformers that are forecasted to experience overload conditions. Performance requirements in the form of yearly capacity (MW) and energy (MWh) grid needs, along with corresponding hourly peak MW and energy profiles, are provided in the EOI. The NPV replacement or deferral value of the traditional wires solution is also included to provide guidance on the potential cost-competitiveness of NWA solutions.

Upon receiving sufficient interest to develop cost-competitive grid-scale renewable projects or aggregating DER/EE projects in the identified locations to address the distribution grid need, we intend to issue targeted RFPs to procure the grid need resources under the Framework for Competitive Bidding.

11.2.6 Grid Services Competitive Procurement

In addition to programs, there are opportunities to acquire customer energy resources through competitive procurements as we have done over the past several years through grid service purchase agreements.

We plan to continue to seek grid services through contractual agreements. Based on the EE supply curve analysis we believe that including energy efficiency as part of the grid services would help to complement existing EE programs, accelerate adoption of energy efficiency, allow for competitive market pricing, and target location-specific benefits.

Resilience and Microgrids

As discussed in Sections 7 and 10, resilience is an important part of the Integrated Grid Plan. We currently have in place a microgrid services tariff and a utility-owned and -operated microgrid, the Schofield Generation Station, in partnership with the U.S. Army to support critical operations. We are also seeking to develop a microgrid for the North Kohala community through a competitive procurement. In the case of North Kohala, the value of the microgrid includes the deferral of a second sub-transmission line (i.e., an NWA) to supply North Kohala whenever there is an outage on the sub-transmission line that feeds the community. We believe that enhancing the resilience of communities through competitive procurement of resilience services would substantially meet the objectives of Act 200 and the Public Utilities Commission's microgrid services proceeding. We plan to apply the lessons learned of the North Kohala RFP and implementation to future procurements that would identify potential microgrid opportunities that are aligned with our ETIPP, equity, resilience system hardening program, and Resilience

Working Group efforts. A procurement would also allow the market to determine the value and compensation for resilience services, provide flexibility to determine the performance and capabilities needed for each unique microgrid opportunity, the best way to integrate and use DER for resilience, determine the supply and demand for microgrids in Hawai'i, and identify prospective developers of microgrids. Additional valuations of resilience consistent with methods currently contemplated by the industry as discussed in Section 7 may also be considered.

11.2.7 Revised Portfolio

Following the selection of programs and projects in the Integrated Grid Plan procurements, near-term generic resources identified in the preferred resource plan to meet grid needs will be replaced by the actual procured resource. In the next cycle of Integrated Grid Planning or as part of smaller updates, these resources will be assumed as planned additions and a starting point from which incremental grid needs can be identified.

12. Securing Generation Reliability and Assessing Risks

We performed an in-depth generation reliability analysis to establish conditions and pathways to deactivate, retire, or, in some cases, accelerate retirement of fossil fuel–based generators. This section further describes the risks and uncertainties and potential ways to mitigate them.

In our discussions with customers, reliability remains of paramount importance as we navigate the transition to 100% renewable energy. We must provide reliable service through the transition, especially as we modernize our generation portfolio. To have an unreliable system would undermine the trust we have with our customers and prevent us from achieving our desired goals.

The existing generating fleet is becoming increasingly less reliable because of age and the way we now operate the grid. We need new, modern generators that can more easily adapt to the changing grid that will be dominated by solar, wind, and energy storage resources. New, modern generators also come with higher reliability compared to the existing fossil fuel–based generators.

Generation reliability is an area of concern in Performance-Based Regulation and is intertwined with State policy to retire fossil fuel–based generation as soon as practicable, and the risks associated with continuing to operate our aging generation fleet well past its original design life.

In the Performance-Based Regulation proceeding, the Public Utilities Commission published a Staff Proposal of performance incentive mechanisms to address areas of concern, including grid reliability and timely retirement of fossil fuel–based generation. The Public Utilities Commission staff's objectives in proposing performance incentives in these areas are to ensure adequate planning and operations of grid reliability, and accelerate integration of renewable resources ahead of retirement schedules.

In addition, through Order 32053, Ruling on RSWG Work Product, in Docket 2011-0206, the Public Utilities Commission made the following observations in ordering the development of Power Supply Improvement Plans, which are addressed in this section:

1. The impact each retirement, without replacement, would have on adequacy of power supply and reserve margins under existing capacity planning criteria;

2. An analysis of how the capacity value of solar, wind, energy storage, and demand response resources will be factored into the determination of the adequacy of power supply;
3. An analysis of feasibility of utilizing existing power plant sites to locate new, quick-start, fuel-efficient, flexible generation, to leverage existing site transmission and fuel supply infrastructure capacity that would be freed-up by retirements of existing generating units (Order No. 32053 at 92-93)

Moreover, the 2020 management audit conducted by the Public Utilities Commission noted our current generating fleet operating risk. The auditor states that “despite best efforts, the risk of failures in parts of the plants—including catastrophic failures—will continue to increase … in our estimation this is an important risk that should not be disregarded and contingency plans should be developed.” (Hawaiian Electric Management Audit Final Report at 168).

In the following section we use data and analysis to address these issues and offer a path forward to mitigate these risks.

12.1 Deactivation of Fossil Fuel–Based Generators

For the purposes of identifying grid needs our analysis assumed that certain amounts of firm fossil fuel–based generating capacity would be removed from operations. The actual deactivation or retirement of generation from service is conditioned upon several factors, including whether sufficient resources have been acquired and placed into service to provide replacement grid services, underwent a proving period to ensure reliable and stable operation, among other considerations, such as overall system reliability and resilience.

The planned removal-from-service schedules for O‘ahu, Hawai‘i Island, and Maui are provided below in Table 12-1. These schedules represent initial assumptions made on the timing for the removal of utility-owned, fossil fuel–based generating units based primarily on age or environmental regulations.

Retirement decisions are permanent and irreversible, and in some cases, as described below, are forced by environmental compliance or our ability to obtain spare parts to continue operations of the generator.

Table 12-1. Planned Removal-from-Service Assumptions for O‘ahu, Hawai‘i Island, and Maui

Year	O‘ahu	Hawai‘i Island	Maui
2024	Waiau 3–4 removed from service		
2025		Puna Steam on standby	
2027	Waiau 5–6 removed from service	Hill 5–6 removed from service	Kahului 1–4, Mā‘alaea 10–13 removed from service
2029	Waiau 7–8 removed from service		
2030			Mā‘alaea 1–3, 4–9 removed from service
2033	Kahe 1–2 removed from service		
2037	Kahe 3–4 removed from service		
2046	Kahe 5–6 removed from service		

Deactivation is a state where there is no present intention to run the unit, but it is available for reactivation in an emergency. The unit is laid up and preserved and can be reactivated in a number of months if needed.

The Hill 5 and 6 and Kahului 1–4 generators are slated for retirement in their designated years to comply with the State Implementation Plan associated with the U.S. Environmental Protection Agency's Regional Haze Rule. Likewise, the Puna Steam unit will switch to a cleaner fuel and likely be placed in standby status for the same reasons. Standby status for Puna Steam will improve the resilience of the Hawai'i Island system. In May 2018, as a result of the loss of Puna Geothermal Venture from the Kilauea lava eruption, Puna Steam was brought back from standby status, which was critical to meet customer power demands.

Mā'alaea generating unit 7 will be required to install emission reduction technology by the end of 2027. In the future, other units may be subject to further operational limitations, emission controls, or forced retirements to meet environmental compliance needs.

Mā'alaea generators 10–13 have limited life remaining because the engine manufacturer has declared the engines obsolete and notified Hawaiian Electric that spare parts may no longer be available in the future. Because these are unique engines, aftermarket parts supply is not reliable. At this time we have secured parts to allow for the units to continue to operate for the next few years. At the same time, the Hawai'i Department of Health has identified the need for emission reductions for these units for the U.S. Environmental Protection Agency's Regional Haze rule. Such emission reduction systems would require significant investments in obsolete units as previously described. Therefore, we will be required to retire the units between 2029 and 2035 (one in 2029, one in 2030, and two in 2035). However, because of the obsolescence issue, we believe that the units would reach end of life between 2027 and 2029. Our plans include ensuring that new resources are brought online prior to these generating units reaching end of life. However, given the age of our generating fleet, it is possible that other generating units may be unexpectedly subject to parts obsolescence in the future.

Figure 12-1 through Figure 12-4 illustrate the age of the current Hawaiian Electric–owned generating fleet, which has served customers well over the past 70 years.

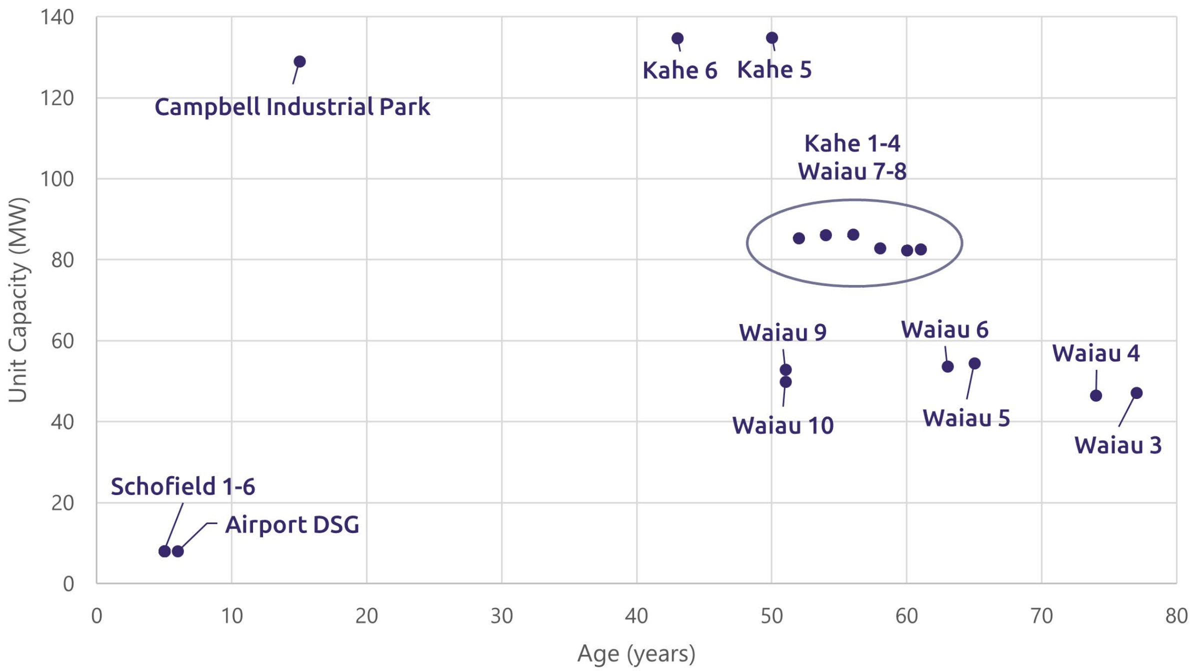


Figure 12-1. O'ahu: size and age of utility-owned generating units

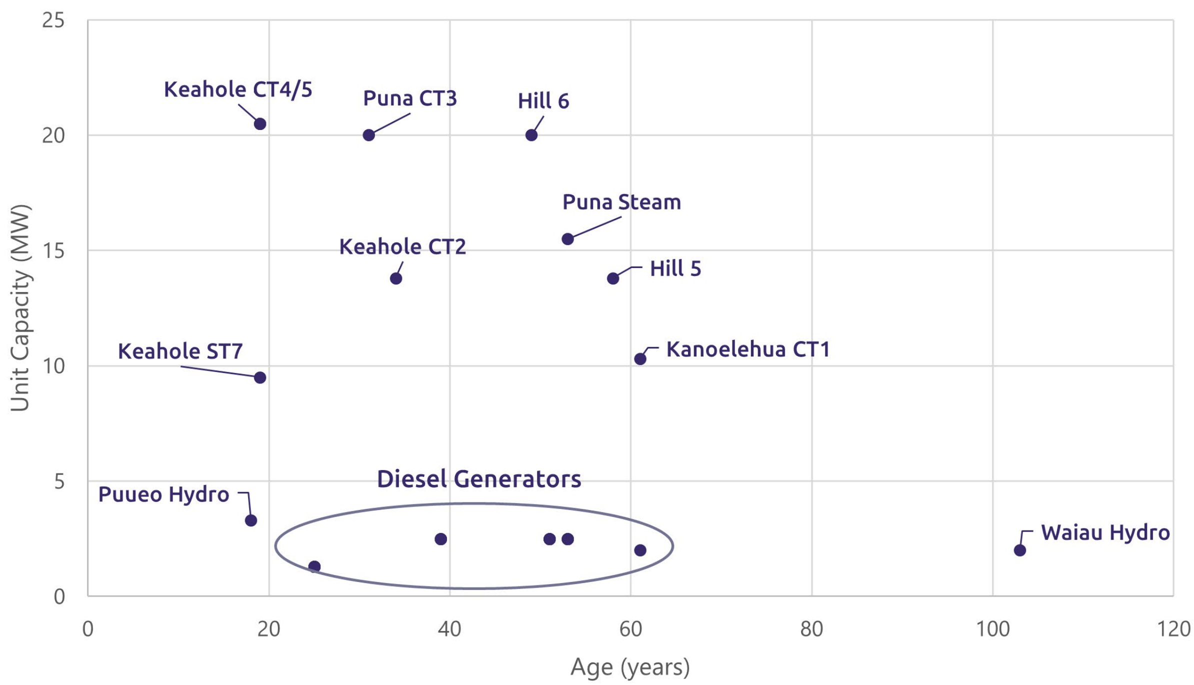


Figure 12-2. Hawai'i Island: size and age of utility-owned generating units

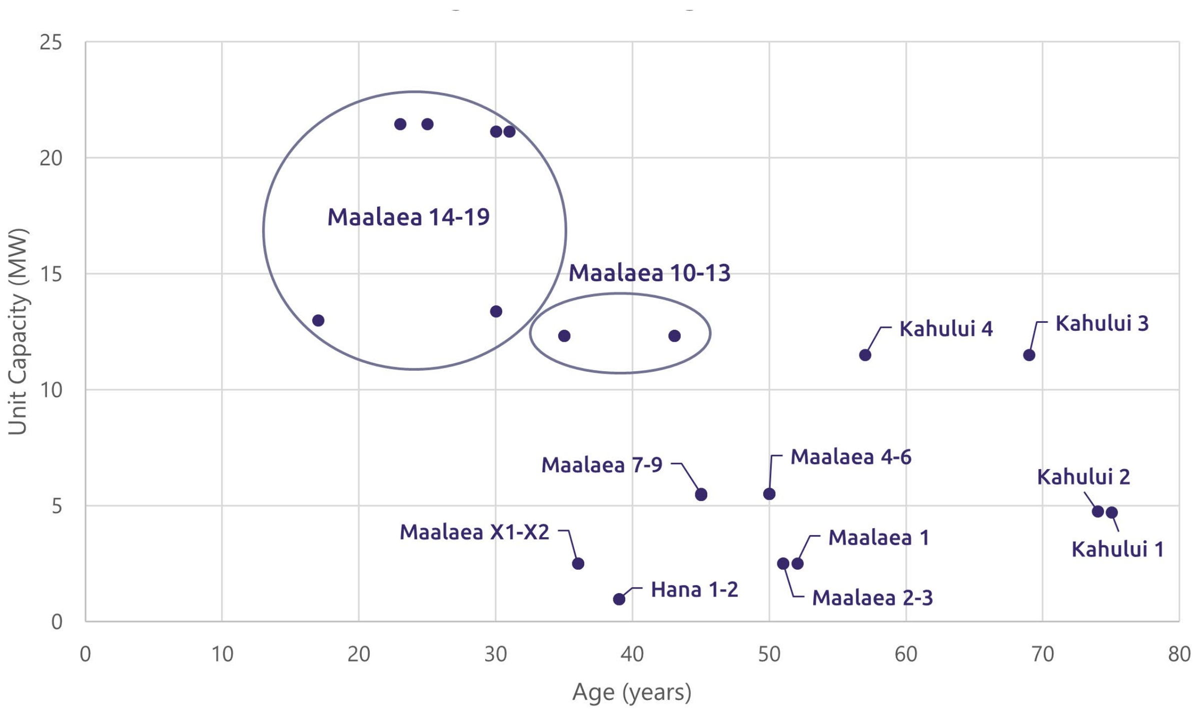


Figure 12-3. Maui: size and age of utility-owned generating units

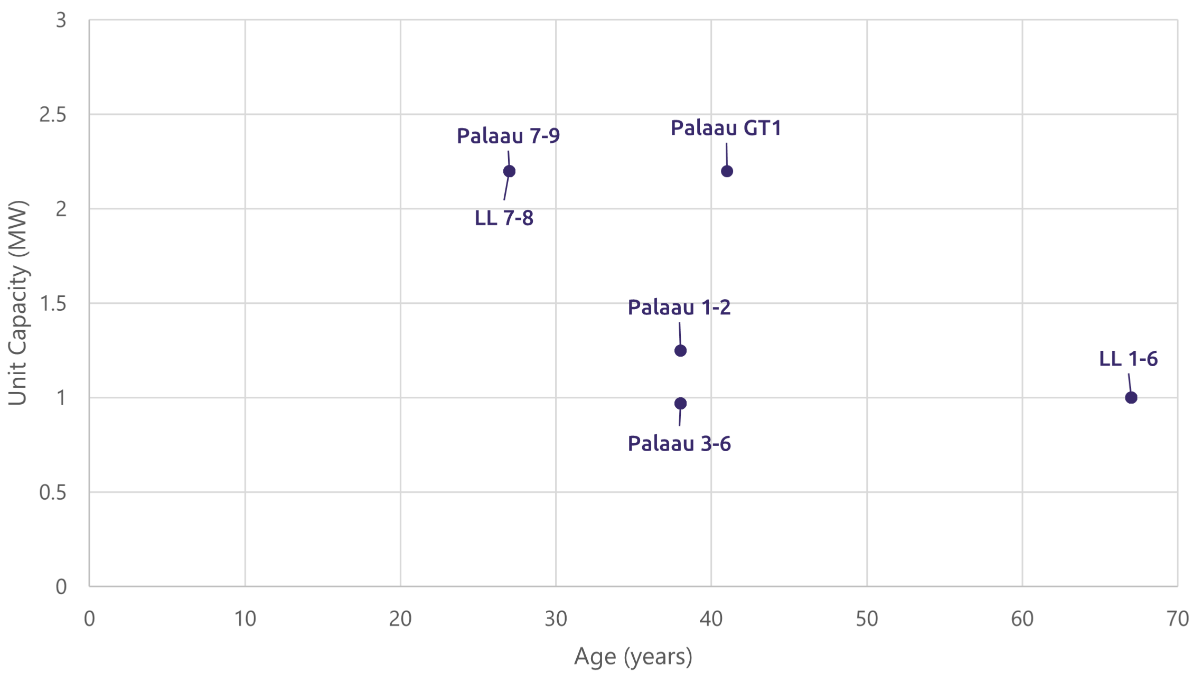


Figure 12-4. Moloka'i and Lāna'i: size and age of utility-owned generating units

By necessity, we operate the existing fossil fuel–based generation fleet at lower minimum loads and cycling units more than they were designed to do. As more renewable projects are integrated over the next few years, generating units, especially steam generation units, will be under increasingly variable operations. Operating the 50- to 75-year-old O'ahu fleet, for example, with increased load ramping, low-load operation, and offline cycling accelerates the aging process, which has led to and will continue to cause increasing rates of forced outages and/or derations of firm capacity on a daily basis, as shown in Figure 12-5. These reliability risks must be urgently addressed—this is foundational to achieving the State's decarbonization and renewable energy goals.

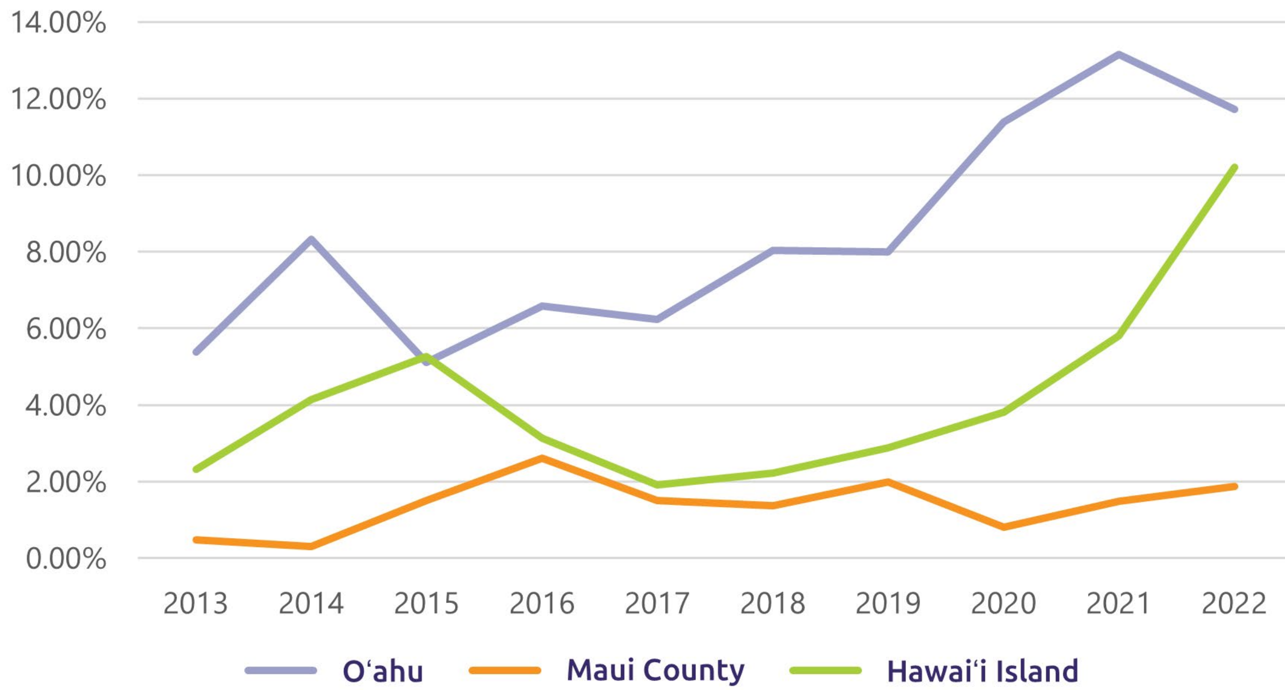


Figure 12-5. Weighted equivalent forced outage rates for O'ahu, Hawai'i Island, and Maui County

Major repairs and maintenance are expected on steam units for the reasons described above. Types of repairs include replacement of major turbine components, boiler tubes sections, major valves, major pumps, and other critical components. Likewise, increased maintenance on valves, boiler refractory, ducts, fans, feed pumps, and other components operating at the edge of their design curves will result in significant increases in operation and maintenance expenses.

To address these acute risks, our resource adequacy analysis identifies pathways to retirement or deactivation of our existing generation fleet as assumed, above, as well as ways to potentially accelerate the retirement or deactivation of our older fossil fuel–based generating units.

In the resource adequacy analysis for Hawai'i Island, we used long-term forced outage rates that may not wholly reflect the upward trend in outages observed in the last few years in Figure 12-5. The Hawai'i Island analysis may need to be revised in future analyses to reflect recent events including significant outages at Hamakua Energy Partners that has prompted calls for conservation.

12.2 Growth in Electric Vehicles

Several drivers for near–term growth of EV adoption also pose risks to ensuring sufficient adequacy of supply. Commitments by car rental companies and vehicle manufacturers will increase the availability and diversity of electric vehicles while County and State commitments will increase the coverage of the EV charging network. These commitments will encourage customers to adopt electric vehicles and as electric vehicles become more prevalent, electric demand will increase as these cars will need to be charged from the grid.

Several trends in EV adoption today already underscore the importance of proactive planning for electric vehicles:

- Standard & Poor's estimates that global EV sales grew by about 36% in 2022[35]
- Hawaiʻi State Energy Office data show 26% year-over-year growth in new EV/plug-in hybrid registrations in Hawaiʻi for 2022[36]

Commitments made by car rental companies and vehicle manufacturers as well as County and State governments will impact near-term EV adoption.

- Avis has plans to implement EV charging stations across all Hawaiʻi airports[37]
- Hertz aims to convert 25% of its fleet to electric by the end of 2024[38]
- General Motors, Ford, and Stellantis pledged 50% of new EV sales by 2030[39]
- The Hawaiʻi Department of Transportation has committed to deploy EV charging infrastructure and electrify its light-duty fleet[40]
- The City and County of Honolulu is converting its vehicle and bus fleet to all electric by 2035[41]

It's not a matter of if, but when EV adoption accelerates. Given the development time for renewable projects or firm generation, we must have sufficient capacity several years before it's needed. The load growth from accelerated EV adoption could happen quickly; for example, a State or federal policy could quickly ramp up EV adoption like the customer-sited solar boom under net energy metering in the 2010s. Because of this risk, Section 12.3 examines the High Load forecast, which incorporates the High EV load layer where aggressive policies are put into place to decarbonize light-duty vehicles and eBuses in the transportation sector.

[35] https://www.spglobal.com/commodityinsights/en/market-insights/blogs/metals/013123-ev-sales-momentum-to-face-challenges-in-2023-but-long-term-expectations-unaffected

[36] See Vehicle Registrations Fuel Types by Month CSV data set at: https://energy.hawaii.gov/energy-data/

[37] https://www.civilbeat.org/2023/02/honolulus-new-airport-rental-center-has-lots-of-electric-cars-but-only-one-charging-station/

[38] https://www.thedetroitbureau.com/2023/01/rental-car-giant-enterprise-backs-equitable-ev-charging-infrastructure-expansion/

[39] https://www.protocol.com/climate/electric-vehicle-automaker-goals

[40] https://hidot.hawaii.gov/blog/2021/04/14/first-electric-vehicles-picked-up-through-the-statewide-multi-agency-service-contract-arrive/

[41] https://www.resilientoahu.org/transportation

12.3 Generation Reliability Risk Assessment

Based on our experience, acute risks and uncertainties come with large-scale development of both solar and wind generation. We developed reliability curves that provide insight into how reliability may change if the optimal plans (as described in Section 8) are not realized or experience delays. Risks are particularly important to understand as the execution of project development has encountered significant challenges over the past several years and the degrading reliability of our existing generation system.

12.3.1 O‘ahu

Uncertainty in forecasted electricity demand is a large source of risk for O‘ahu. Section 8.2.2 shows how the planned O‘ahu system meets reliability targets in 2030 and 2035 but requires additional resources in a High electricity demand scenario. This section shows how adding or removing resources from the O‘ahu system affects reliability metrics.

12.3.1.1 Hybrid Solar Reliability Impacts

As described earlier, if O‘ahu obtains 450 MW of hybrid solar and 300 MW of firm generation by 2030 through the Stage 3 procurement, the system should meet the loss of load expectation target of 0.1 day per year. However, if we do not obtain any new firm generation, the system may not meet the loss of load expectation target depending on how much variable renewable generation is procured and placed into service.

To determine the sensitivity of the loss of load expectation based on the amount of variable renewable generation added in 2030, we removed any new firm generation that we plan to acquire through the Stage 3 procurement and varied the amount of future hybrid solar added in 2030.

As shown in Figure 12-6, in 2030, without any new firm generation, nearly 1,600 MW of hybrid solar is needed to meet the 0.1 day/year target. Shown below is the relationship between the loss of load expectation and future hybrid solar added in 2030. Figure 12-6 shows that as we incrementally add more future hybrid solar in 2030, its contribution toward reliability improvements greatly diminishes (particularly after 600 MW of hybrid solar is integrated onto the system), highlighting the need for a diverse resource portfolio. We expect similar results if we replace large-scale solar with distributed, customer-sited hybrid solar.

Importantly, this chart demonstrates the sensitivity of reliability that O‘ahu has to small changes in capacity. For example, 200 MW of hybrid solar results in a significant swing (approximately 8.7 days per year) in reliability. We consider this point a significant consideration in how we plan and procure resources to meet our customers’ reliability expectations.

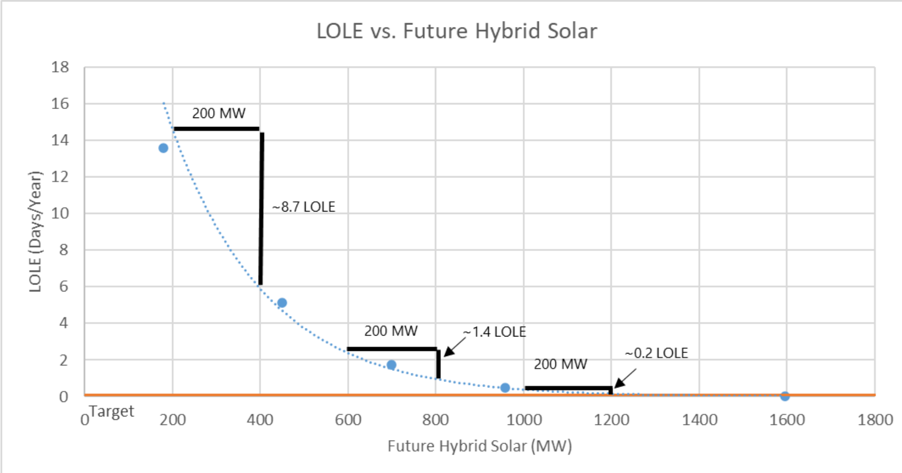


Figure 12-6. O'ahu: relationship between change in loss of load and change in future paired PV hybrid solar capacity, 2030

In Figure 12-7 below we present the unserved energy based on the month and hour of our existing system in 2021 (left) and the scenario where we do not add any new firm generation but obtain 450 MW of hybrid solar (right). With only the 450 MW hybrid solar resource (as targeted in Stage 3 procurement), we may experience significant unserved energy during the morning and evening hours because of the weather-dependent, energy-limited nature of wind, solar, and energy storage.

Hours Beginning	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	0	0	0	0	0	0	0	0	0	0	0	0
1	0	0	0	0	0	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	0	0	0	0	0
5	0	0	0	0	0	0	0	0	0	0	0	0
6	0	0	0	0	0	0	0	0	0	0	0	0
7	0	0	0	0	0	0	0	0	0	0	0	1
8	0	0	0	0	0	0	0	0	0	0	0	0
9	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
11	0	0	0	0	0	0	0	0	0	0	0	0
12	0	0	0	0	0	0	0	0	0	0	0	0
13	0	0	0	0	0	0	0	0	0	0	0	0
14	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
16	0	0	0	0	0	0	0	0	0	0	0	1
17	0	0	0	0	0	0	0	0	0	0	0	4
18	0	0	0	0	0	0	0	0	9	6	3	12
19	0	0	0	0	0	0	0	4	19	9	3	10
20	0	0	0	0	0	0	0	2	10	3	1	7
21	0	0	0	0	0	0	0	1	3	5	1	9
22	0	0	0	0	0	0	0	0	0	1	0	5
23	0	0	0	0	0	0	0	0	0	0	0	3

Max	
131 MW	
0 MW	
Min	

Hours Beginning	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	1	2	10	53	35	31	13	5	0	2	0	0
1	0	1	2	32	29	20	7	3	1	2	0	0
2	0	1	4	29	21	14	5	3	0	1	0	0
3	1	2	6	64	38	32	20	9	2	3	0	0
4	2	4	17	84	45	36	24	10	3	4	0	0
5	2	3	15	73	42	43	19	12	2	4	0	0
6	5	5	23	124	48	49	17	13	5	6	0	0
7	2	4	8	28	18	17	8	1	1	2	0	0
8	1	0	0	6	4	4	3	0	0	1	0	0
9	0	0	0	1	1	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
11	0	0	0	0	0	0	0	0	1	0	0	0
12	0	0	0	0	0	0	0	0	0	0	0	0
13	0	0	0	0	0	0	0	0	0	0	0	0
14	0	0	0	0	0	0	0	0	0	0	0	0
15	0	1	0	1	1	0	1	0	0	1	0	0
16	0	1	0	8	3	1	4	0	0	2	0	0
17	1	6	4	36	23	14	12	0	2	8	0	0
18	3	4	4	30	27	16	10	1	3	3	0	0
19	3	14	16	77	74	60	28	0	9	7	0	0
20	0	2	1	32	31	24	18	0	4	2	0	0
21	1	8	7	84	69	45	34	4	4	7	0	0
22	3	12	37	131	97	86	49	1	12	14	0	0
23	3	11	23	84	90	69	29	1	9	8	0	0

Max	
131 MW	
0 MW	
Min	

Figure 12-7. O'ahu: 2021 existing system (left); no new firm, add 450 MW hybrid solar (right)

We performed the same analysis for 2035. Unlike the 2030 hybrid solar sensitivity, which assumed the base electricity demand forecast, this 2035 sensitivity assumed the High electricity demand forecast. With future uncertainties in EV adoption, we wanted to understand the reliability risks associated with load growth due to electrification of transportation.

In this sensitivity, we assume that we successfully acquire the 450 MW of hybrid solar and 300 MW in 2029 and 200 MW in 2032 of firm generation from Stage 3 procurement. Additional hybrid solar was then added to determine its impact on reliability in 2035. Shown in Figure 12-8, below, is the relationship between the loss of load expectation and incremental additions of hybrid solar in 2035. Similar to 2030, the figure shows that as we add more hybrid solar in 2035, its contribution toward reliability improvements quickly diminishes. It is important to note that, even with resources procured through the Stage 3 procurement and an additional 1,145 MW of hybrid solar, the system may not meet the 0.1 day/year target under the High Load scenario. Based on the relationship shown below, we would need approximately 1,225 MW of hybrid solar in addition to the Stage 3 procurement.

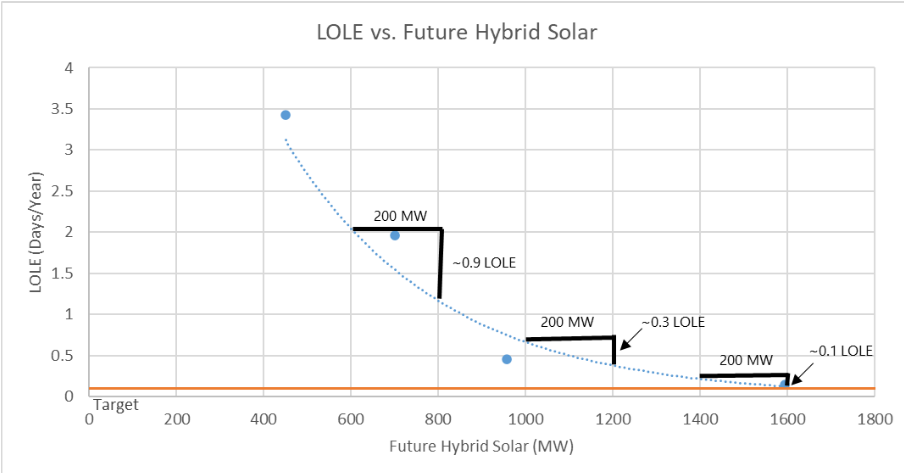


Figure 12-8. O'ahu; relationship between change in loss of load and change in future hybrid solar capacity (High Load scenario, 2035)

In Figure 12-9, we present the unserved energy based on the month and hour of the scenario with and without the additional 1,600 MW of hybrid solar and 500 MW of firm generation. As shown in the image on the right, under the High Load scenario, even with 500 MW of new firm resources and nearly 1,600 MW of hybrid solar, we may still experience unserved energy.

Hours Beginning	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	1	17	3	17	15	20	8	12	11	13	1	1
1	0	9	0	10	4	18	3	3	2	7	0	0
2	0	7	0	5	5	6	3	1	1	3	0	0
3	0	10	1	9	5	14	6	1	0	6	0	0
4	2	15	1	13	8	23	6	1	1	9	0	0
5	2	29	1	13	9	22	9	2	1	10	1	0
6	4	35	3	17	9	35	13	0	4	15	2	2
7	2	36	1	6	2	2	0	1	2	3	0	1
8	1	12	0	2	0	0	1	0	1	1	0	0
9	0	5	0	1	0	0	0	0	1	0	0	0
10	0	2	0	1	0	0	0	0	0	0	0	0
11	0	1	0	0	0	0	0	0	0	0	0	0
12	0	1	0	0	0	0	0	0	0	1	0	0
13	0	0	0	0	0	0	0	0	0	0	0	0
14	0	0	0	0	0	0	0	0	1	1	0	0
15	0	4	0	1	0	1	0	0	5	8	0	0
16	3	13	1	7	2	8	3	1	10	13	1	3
17	7	37	3	21	12	45	13	5	19	28	6	9
18	8	56	3	39	10	96	29	10	21	51	1	5
19	18	114	6	72	34	137	64	6	39	44	3	18
20	2	39	0	44	12	62	32	0	16	13	1	8
21	10	68	4	49	27	62	23	10	26	22	3	7
22	17	85	8	49	26	116	53	12	38	37	9	17
23	13	72	8	59	17	77	28	9	27	38	5	13

Max
137 MW
0 MW
Min

Hours Beginning	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	0	2	0	0	0	0	0	0	1	0	0	0
1	0	0	0	0	0	0	0	0	0	0	0	0
2	0	1	0	0	0	0	0	0	0	0	0	0
3	0	1	0	0	0	1	0	0	1	0	0	0
4	0	1	0	0	0	1	0	0	1	0	0	0
5	0	1	0	0	0	1	0	0	0	0	0	0
6	0	2	0	0	0	0	0	0	1	0	0	0
7	0	2	0	0	0	0	0	0	0	0	0	0
8	0	1	0	0	0	0	0	0	0	0	0	0
9	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
11	0	0	0	0	0	0	0	0	0	0	0	0
12	0	0	0	0	0	0	0	0	0	0	0	0
13	0	0	0	0	0	0	0	0	0	0	0	0
14	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
16	0	0	0	1	0	0	0	0	0	0	0	0
17	0	2	0	2	0	1	0	0	3	0	0	0
18	0	6	0	2	0	0	0	0	3	1	0	0
19	0	17	0	4	0	5	1	0	10	2	0	0
20	0	4	0	1	0	0	0	0	0	0	0	0
21	0	9	0	3	0	1	0	0	5	0	0	0
22	0	14	0	7	0	4	0	0	7	1	0	0
23	0	9	0	5	0	4	2	0	7	1	0	0

Max
137 MW
0 MW
Min

Figure 12-9. O'ahu: add 508 MW firm, add 450 MW hybrid solar, High Load (left); add 508 MW firm, add 1,600 MW hybrid solar, High Load (right)

12.3.1.2Firm Generation Reliability Impacts

We performed an analysis to determine how reliability of the system changes based on the procurement or addition of firm generation. We assume the 450 MW of hybrid solar sought in the Stage 3 procurement and incremented firm generation to determine the impacts to reliability.

As shown in Figure 12-10, in 2030, we may need approximately 200 MW of new firm generation to meet the 0.1 day/year loss of load expectation target. Shown below is the relationship between the 2030 loss of load expectation and varying amounts of firm generation. The figure shows that as more firm generation is added in 2030, the reliability improvements decrease; however, in contrast, significantly less capacity of firm generation is needed to improve reliability by the same measure compared to hybrid solar.

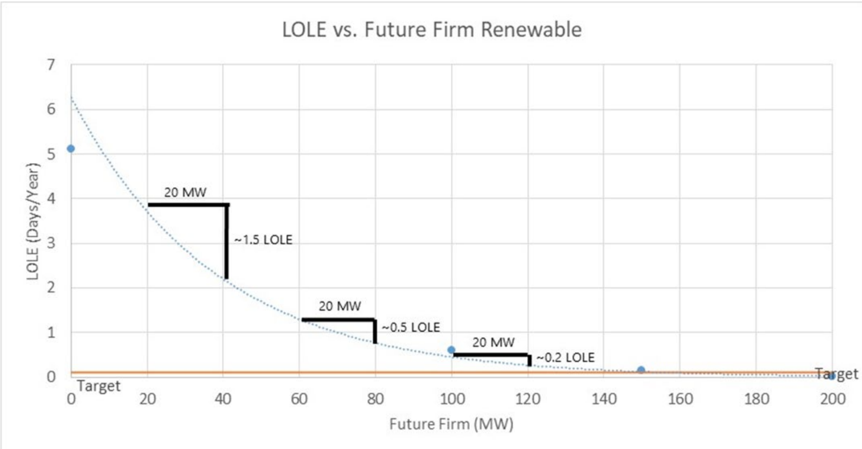


Figure 12-10. O‘ahu: relationship between change in loss of load and change in future firm renewable capacity (2030)

In Figure 12-11 below we present the unserved energy based on the month and hour of the scenario where we do not have new firm generation but have the 450 MW of hybrid solar sought in Stage 3 (left), and the scenario where we add 150 MW of new firm generation along with 450 MW of hybrid solar (right). As shown, the addition of 150 MW of firm generation may help significantly reduce the amount of unserved energy, though we still expect unserved energy during the morning and evening hours.

Hours Beginning	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	0	2	0	0	0	0	0	0	1	0	0	0
1	0	0	0	0	0	0	0	0	0	0	0	0
2	0	1	0	0	0	0	0	0	0	0	0	0
3	0	1	0	0	0	1	0	0	1	0	0	0
4	0	1	0	0	0	1	0	0	1	0	0	0
5	0	1	0	0	0	1	0	0	0	0	0	0
6	0	2	0	0	0	0	0	0	1	0	0	0
7	0	2	0	0	0	0	0	0	0	0	0	0
8	0	1	0	0	0	0	0	0	0	0	0	0
9	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
11	0	0	0	0	0	0	0	0	0	0	0	0
12	0	0	0	0	0	0	0	0	0	0	0	0
13	0	0	0	0	0	0	0	0	0	0	0	0
14	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
16	0	0	0	1	0	0	0	0	0	0	0	0
17	0	2	0	2	0	1	0	0	3	0	0	0
18	0	6	0	2	0	0	0	0	3	1	0	0
19	0	17	0	4	0	5	1	0	10	2	0	0
20	0	4	0	1	0	0	0	0	0	0	0	0
21	0	9	0	3	0	1	0	0	5	0	0	0
22	0	14	0	7	0	4	0	0	7	1	0	0
23	0	9	0	5	0	4	2	0	7	1	0	0

Max
137 MW
0 MW
Min

Hours Beginning	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	0	0	0	0	0	1	0	0	0	0	0	0
1	0	0	0	0	0	0	0	0	0	0	0	0
2	0	0	0	0	1	0	0	0	0	0	0	0
3	0	0	0	0	1	2	0	0	0	0	0	0
4	0	0	0	1	0	3	0	0	0	0	0	0
5	0	0	0	1	2	1	0	0	0	0	0	0
6	0	0	0	0	1	3	0	0	0	0	0	0
7	0	0	0	0	0	0	0	0	0	0	0	0
8	0	0	0	0	0	0	0	0	0	0	0	0
9	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
11	0	0	0	0	0	0	0	0	0	0	0	0
12	0	0	0	0	0	0	0	0	0	0	0	0
13	0	0	0	0	0	0	0	0	0	0	0	0
14	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
16	0	0	0	0	0	0	0	0	0	0	0	0
17	0	0	0	0	0	0	0	0	0	0	0	0
18	0	0	0	0	1	1	0	0	0	0	0	0
19	0	0	0	1	0	0	0	0	1	0	0	0
20	0	0	0	0	2	1	0	0	0	0	0	0
21	0	0	0	1	0	0	0	0	0	0	0	0
22	0	0	0	1	1	0	0	0	0	0	0	0
23	0	0	0	1	0	1	0	0	0	0	0	0

Max
131 MW
0 MW
Min

Figure 12-11. O‘ahu: no new firm, add 450 MW hybrid solar (left); add 150 MW firm, add 450 MW hybrid solar (right)

We also performed analysis to determine how reliability changes based on the procurement of additional firm generation above the 508 MW targeted in the Stage 3 procurement. Similar to the 2035 variable sensitivity performed, this 2035 firm generation sensitivity assumed the High Load forecast to ensure that the Integrated Grid Plan is capable of reliably serving load growth from accelerated growth of electric vehicles. Similar to the 2035 analysis on hybrid solar, we assume that 450 MW of hybrid solar, and 500 MW of firm generation sought through the Stage 3 procurement are in service.

Shown below in Figure 12-12 is the relationship between the loss of load expectation and increments of new firm generation in 2035. Based on the results, we would need close to 200 MW of additional firm generation above the 500 MW of firm generation sought in the Stage 3 procurement, to meet the 0.1 day/year target under a High electricity demand forecast. We also observe the outsized impact the addition (or forced outage) that 100 MW of firm generation can have on reliability, with a change of approximately 4.6 days per year of loss of load.

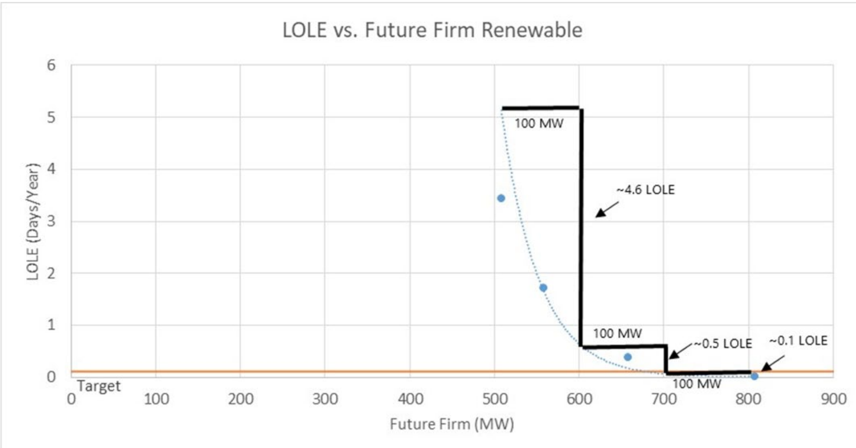


Figure 12-12. O‘ahu: relationship between change in loss of load and change in future firm capacity (High Load scenario, 2035)

In Figure 12-13 below we present the unserved energy based on the month and hour of the scenario with and without an additional 650 MW of firm generation. As shown in the image on the right, under the High electricity demand scenario we may still experience unserved energy.

Hours Beginning	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	0	2	0	0	0	0	0	0	1	0	0	0
1	0	0	0	0	0	0	0	0	0	0	0	0
2	0	1	0	0	0	0	0	0	0	0	0	0
3	0	1	0	0	0	1	0	0	1	0	0	0
4	0	1	0	0	0	1	0	0	1	0	0	0
5	0	1	0	0	0	1	0	0	0	0	0	0
6	0	2	0	0	0	0	0	0	1	0	0	0
7	0	2	0	0	0	0	0	0	0	0	0	0
8	0	1	0	0	0	0	0	0	0	0	0	0
9	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
11	0	0	0	0	0	0	0	0	0	0	0	0
12	0	0	0	0	0	0	0	0	0	0	0	0
13	0	0	0	0	0	0	0	0	0	0	0	0
14	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
16	0	0	0	1	0	0	0	0	0	0	0	0
17	0	2	0	2	0	1	0	0	3	0	0	0
18	0	6	0	2	0	0	0	0	3	1	0	0
19	0	17	0	4	0	5	1	0	10	2	0	0
20	0	4	0	1	0	0	0	0	0	0	0	0
21	0	9	0	3	0	1	0	0	5	0	0	0
22	0	14	0	7	0	4	0	0	7	1	0	0
23	0	9	0	5	0	4	2	0	7	1	0	0

Max
137 MW
0 MW
Min

Hours Beginning	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	0	0	0	2	0	6	0	0	0	1	0	0
1	0	0	0	1	0	2	0	0	0	0	0	0
2	0	0	0	1	0	1	0	0	0	1	0	0
3	0	0	0	1	0	1	0	0	0	0	0	0
4	0	0	0	1	0	3	0	0	0	1	0	0
5	0	1	0	2	0	4	0	0	0	1	0	0
6	0	1	0	0	0	2	0	0	0	3	0	0
7	0	2	0	0	0	0	0	0	0	1	0	0
8	0	0	0	0	0	0	0	0	0	0	0	0
9	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
11	0	0	0	0	0	0	0	0	0	0	0	0
12	0	0	0	0	0	0	0	0	0	0	0	0
13	0	0	0	0	0	0	0	0	0	0	0	0
14	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	2	0	0
16	0	1	0	1	0	2	0	0	0	3	0	0
17	0	5	0	3	1	8	0	0	1	6	0	0
18	0	5	0	3	1	8	1	0	0	2	0	0
19	0	8	0	8	0	16	2	0	1	3	0	0
20	0	6	0	2	0	5	0	0	0	1	0	0
21	0	6	0	2	0	10	0	0	0	3	0	0
22	0	4	0	10	4	18	3	0	1	5	0	0
23	0	4	0	9	2	8	2	0	0	9	0	0

Max
137 MW
0 MW
Min

Figure 12-13. O‘ahu: add 508 MW firm, add 450 MW hybrid solar, High load (left); add 658 MW firm, add 450 MW hybrid solar, High load (right)

12.3.1.3Fossil Fuel Retirement Risk Assessment

Given that both the Base and Land-Constrained scenario meet the loss of load expectation target in 2030, we completed analyses to determine whether we could deactivate additional fossil fuel–based generators while maintaining reliability. As shown in Table 12-2, in the Base scenario and under the right system conditions, an additional 600 MW of existing fossil-fuel firm generation could be deactivated and still meet the 0.1 day/year loss of load expectation target. In the Land-Constrained scenario, we may be able to deactivate an additional 170 MW of existing fossil-fuel firm generation.

Table 12-2. Probabilistic Analysis: Results Summary, Oʻahu 2030, Retirement Sensitivity

Scenario	Existing Firm (MW)	New Firm (MW)	Stage 3 RFP (MW)	Future Wind (MW)	Future Hybrid Solar (MW)	Future Standalone BESS (MW)	LOLE (Days/ Year)	LOLEv (Event/ Year)	LOLH (Hours /Year)	EUE (MWh/ Year)	EUE (%)
Base	1,173	300	450	164	1,145	167	0.00	0.00	0.00	0.00	0.000
Deactivation of 600 MW of firm gen.	567	300	450	164	1,145	167	0.04	0.08	0.22	0.04	0.001
Land-Constrained	1,173	300	450	0	0	54	0.00	0.00	0.01	0.00	0.000
Deactivation of 170 MW of firm gen.	1,008	300	450	0	0	54	0.06	0.11	0.20	0.02	0.000

Given that both the Base and Land-Constrained scenarios meet the loss of load expectation target in 2035, we completed analyses to determine whether we could deactivate additional generators while maintaining reliability.

Table 12-3 focuses on the Base scenario. If we acquire 500 MW of new firm generation, 1,600 MW of hybrid solar along with 400 MW of offshore wind and 164 MW onshore wind, we may be able to deactivate an additional 440 MW of additional fossil-fuel firm generation. If we acquire only 300 MW of new firm generation from the Stage 3 procurement, an additional 170 MW of fossil-fuel firm generation could be deactivated.

Table 12-3. Probabilistic Analysis: Results Summary, Oʻahu 2035, Retirement Sensitivity, Base Scenario

Scenario	Existing Firm (MW)	New Firm (MW)	Stage 3 RFP (MW)	Future Wind (MW)	Future Hybrid Solar (MW)	Future Standalone BESS (MW)	LOLE (Days/ Year)	LOLEv (Event/ Year)	LOLH (Hours /Year)	EUE (MWh/ Year)	EUE (%)
Base (incl. 400 MW offshore wind)	800	508	450	564	1,145	167	0.00	0.00	0.00	0.00	0.000
Deactivation of 440 MW firm gen.	359	508	450	564	1,145	167	0.01	0.03	0.04	0.00	0.000
Base (300 MW new firm gen.)	800	300	450	564	1,145	167	0.01	0.02	0.07	0.01	0.000
Deactivation of 170 MW firm gen.	628	300	450	564	1,145	167	0.01	0.02	0.04	0.01	0.000
Deactivation of 440 MW firm gen.	359	300	450	564	1,145	167	0.72	1.60	3.11	0.52	0.007

Table 12-4 focuses on the Land-Constrained scenario. If we acquire 500 MW of new firm generation, 450 MW of hybrid solar along with 400 MW of offshore wind and 30 MW onshore wind, we may be able to deactivate an additional 170 MW of fossil fuel firm generation. If, however, we acquired only 300 MW of new firm generation through the Stage 3 procurement, we may need to reactivate an additional 170 MW of fossil fuel firm generation to meet our reliability target.

Table 12-4. Probabilistic Analysis: Results Summary, Oʻahu 2035, Retirement Sensitivity, Land-Constrained Scenario

Scenario	Existing Firm (MW)	New Firm (MW)	Stage 3 RFP (MW)	Future Wind (MW)	Future Hybrid Solar (MW)	Future Standalone BESS (MW)	LOLE (Days/ Year)	LOLEv (Event/ Year)	LOLH (Hours /Year)	EUE (MWh/ Year)	EUE (%)
Land-Constrained (incl. 400 MW offshore wind)	800	508	450	430	0	194	0.00	0.01	0.01	0.00	0.000
Deactivation of 170 MW firm gen.	628	508	450	430	0	194	0.01	0.04	0.06	0.01	0.000
Deactivation of 440MW Firm Gen.	359	508	450	430	0	194	0.44	0.95	2.29	0.37	0.005
Land-Constrained (300 MW new firm gen.)	800	300	450	430	0	194	0.22	0.40	0.86	0.12	0.002
Reactivation of 170 MW existing firm gen.	965	300	450	430	0	194	0.05	0.10	0.21	0.04	0.001

12.3.1.43-Day Energy Profile, High Unserved Energy Day

The reliability analyses are the average of the 250 simulation samples. Even though the loss of load expectation meets or exceeds 0.1 day per year, individual samples of weather and firm generation outage combinations may produce significant unserved energy. We show in Figure 12-14 a sample with significant unserved energy, even with 1,600 MW of future hybrid solar.

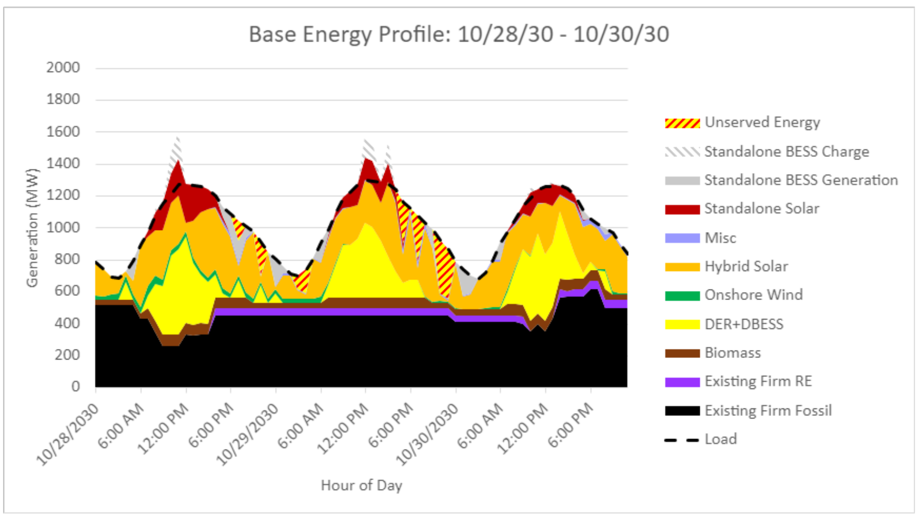


Figure 12-14. O'ahu: detailed energy profile, 2030 high unserved energy load day; no new firm, add 1,600 MW hybrid solar

Figure 12-15 shows another sample with significant unserved energy in the Land-Constrained scenario with 300 MW of new firm generation and the reactivation of 170 MW of firm generation.

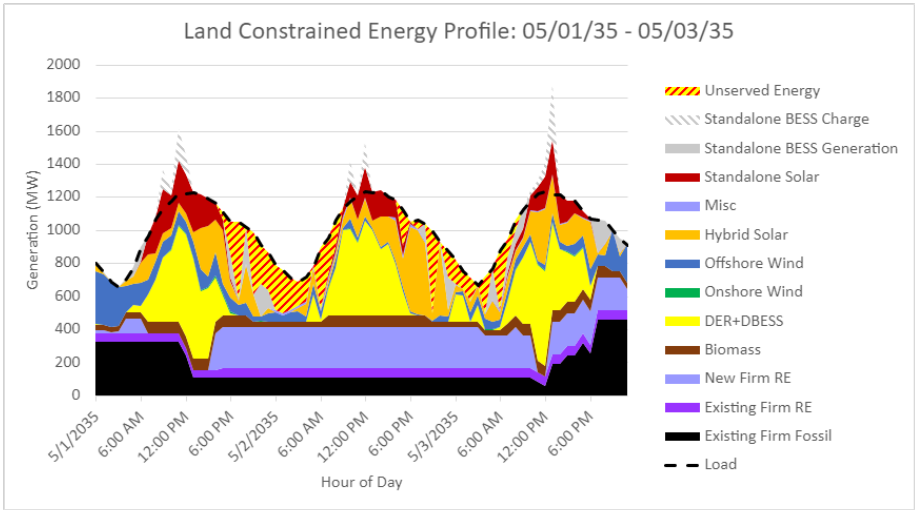


Figure 12-15. O'ahu: detailed energy profile, 2035 high unserved energy load day; add 300 MW firm, add 450 MW hybrid solar, add 400 MW offshore wind, add 170 MW existing firm

In both figures, we see the important role that a resource with the attributes like a firm generator play in the reliability of the system. The significant duration and magnitude of the unserved energy on the system demonstrates the need for a resource with attributes similar to a firm generator.

12.3.2 Hawai‘i Island

Uncertainty in forecasted electricity demand is a large source of risk for Hawai'i Island. Section 8.3.2 shows how the planned Hawai'i Island system meets reliability targets in 2030 and 2035 but requires additional resources in a High electricity demand scenario. This section analyzes how adding or removing resources from the Hawai'i Island system affects reliability metrics.

Volcanic activity is an environmental risk unique to Hawai'i Island. Volcanic ash can reduce the effectiveness of solar resources and lava flows can also impact resources in their path.

12.3.2.1Hybrid Solar Reliability Impacts

As described earlier, the Base scenario meets or exceeds the reliability target. Therefore, for the purposes of assessing the reliability risks of the Hawai'i Island system, the scenarios shown below assume the 2030 Base scenario and the removal of the Hamakua Energy Partners plant, whose PPA is set to expire at the end of 2030.

- Even without the full Stage 3 procurement target of 140 MW of hybrid solar, the 2030 system's loss of load expectation is less than 0.1 day per year.

If a system has a high loss of load expectation, even small amounts of added resources can dramatically improve the system's loss of load expectation. However, continually adding resources has diminishing returns. The planned Base 2030 system already has a low loss of load expectation so additional resources would have a minimal benefit to the system's loss of load expectation. Though adding resources to an already stable system may not impact loss of load expectation as much, the resources still act as a safety net should other resources be unexpectedly brought offline (e.g., the 2018 Kilauea eruption that forced Puna Geothermal Venture out of service for an extended period or recent extended outages experienced on Hawai'i Island).

Once loss of load expectation exceeds 0.1 day per year it rises quickly if more resources are brought offline. Though the effects are not as dramatic as when removing comparable amounts of firm resources, there should be caution when removing resources because they have a growing impact on the system's loss of load expectation as more resources are retired.

Figure 12-16 shows the relationship between change in loss of load and change in Stage 3 hybrid solar capacity for the Base Load scenario in 2030 on Hawai'i Island.

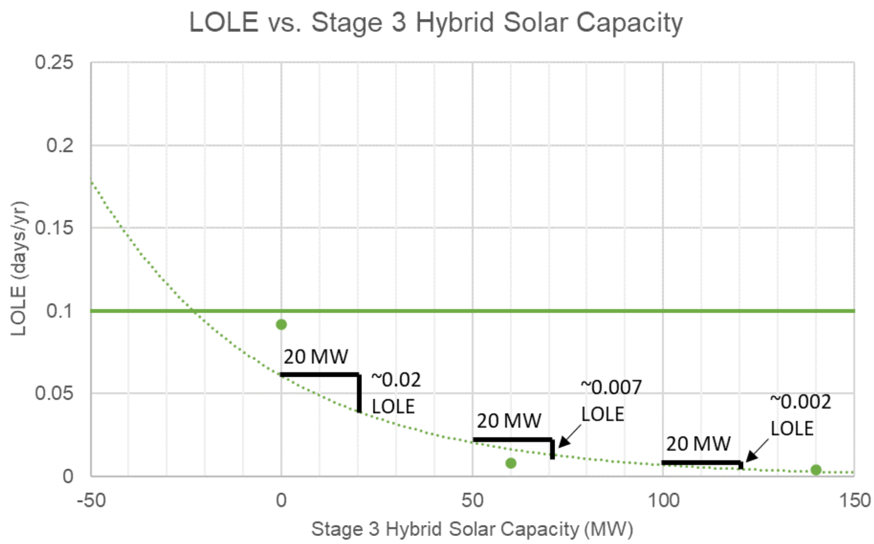


Figure 12-16. Hawaiʻi Island: relationship between change in loss of load and change in Stage 3 paired PV hybrid solar capacity (Base Load scenario, 2030)

The heat map shown in Figure 12-17 below illustrates when we expect unserved energy to occur and at what quantities for the scenario shown in Figure 12-16 with a loss of load expectation around 0.1 day per year (Base scenario, remove 60 MW firm generation, add 0 MW hybrid solar). The quantities shown are an average of all 250 samples. When the Puna Geothermal Venture plant is offline for maintenance we see much of the unserved energy occurring in March during the evening peak and early morning hours.

Hours Beginning	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	0.0	0.0	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	0.0	0.1	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
7	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
19	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Max	1 MW
Min	0 MW

Figure 12-17. Hawaiʻi Island: remove 60 MW firm, add 0 MW hybrid solar heat map (Base scenario 2030)

We performed the same analysis for 2035. Unlike the 2030 hybrid solar sensitivity, which assumed the Base electricity demand forecast, the 2035 sensitivity assumed the High electricity demand forecast. With future uncertainties in EV adoption, we wanted to understand the reliability risks associated with load growth due to electrification of transportation.

The 140 MW of hybrid solar from Stage 3 was assumed to be in service.

- In a High Load scenario if no new resources are added, the loss of load expectation is above 10 days per year.

We also observe that small changes in hybrid solar capacity can significantly change the reliability of the system, though there are diminishing returns. For example, just 50 MW of hybrid solar at lower penetrations reduces loss of load expectation by approximately 17 days per year and at higher penetrations 1 day per year. The planned High load 2035 system has a high loss of load expectation so if a project selected through a competitive procurement fails to reach commercial operations or an unexpected outage of the solar plant takes place, significant adverse impacts to reliability are expected in a High load scenario. This trend is also evident in the firm resource reliability curves. Figure 12-18 shows the relationship between change in loss of load and change in future hybrid solar capacity on Hawai'i Island for the High Load scenario in 2035.

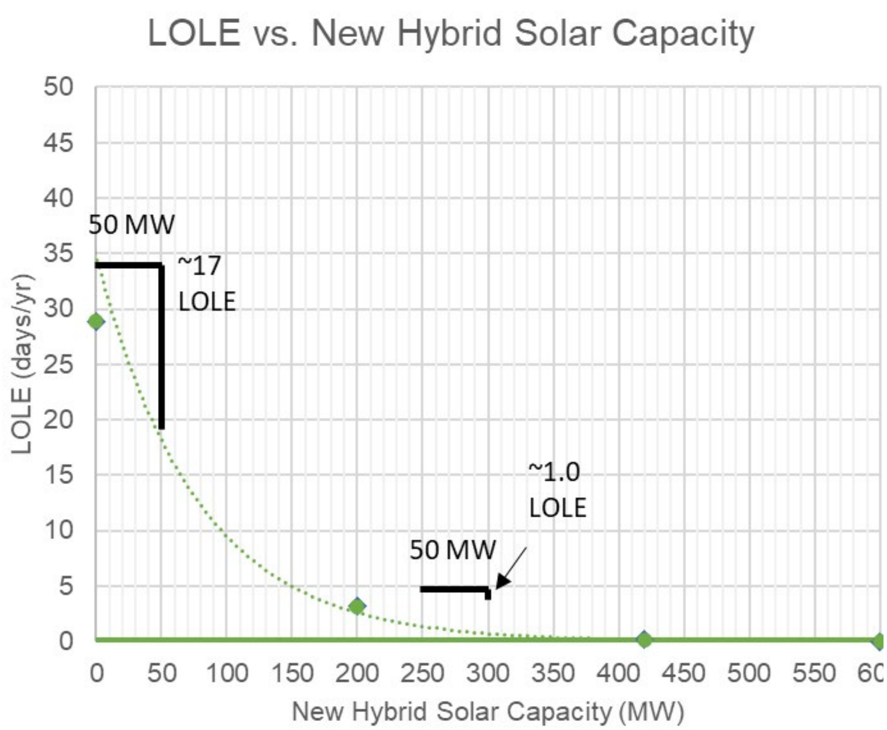


Figure 12-18. Hawai'i Island: relationship between change in loss of load and change in new hybrid solar capacity (High Load scenario, 2035)

The heat map in Figure 12-19 shows when we expect unserved energy to occur and at what quantities for the scenario shown in Figure 12-18 above with a loss of load expectation around 0.1 day per year (High electricity demand forecast, no new firm generation, and 420 MW of hybrid solar). The quantities shown are an average of all 250 samples. With fewer firm resources, unserved energy is expected during the early morning hours when firm resources are down for maintenance and during bad solar condition months like December.

Hours Beginning	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.1	0.5
1	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3
2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.3
3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.2
4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.3
5	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.4
6	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.9
7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7
8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
10	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
11	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0
15	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.4	0.0	0.0	0.1	0.2
16	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
17	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3
18	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
23	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.1

Max
1 MW
0 MW
Min

Figure 12-19. Hawai'i Island: add 0 MW firm, add 420 MW hybrid solar; EUE heat map (High Load scenario, 2035)

12.3.2.2Firm Generation Reliability Impact

For the purposes of assessing the reliability risks of the Hawai'i Island system, the scenarios shown below assume the 2030 Base load and the removal of the Hamakua Energy Partners plant, whose PPA is set to expire at the end of 2030. The 140 MW of hybrid solar from Stage 3 is assumed to be in service. In a 2030 Base scenario, a loss of load less than 0.1 day per year is expected even if Hamakua Energy Partners and some additional firm is brought offline unexpectedly.

We also observe that even small amounts of added resources can dramatically reduce the system's reliability. However, continually adding resources has diminishing returns on reliability improvements. Though adding resources to an already stable system like the planned Base load 2030 system may not impact loss of load expectation as much, the resources still act as a safety net should other resources be unexpectedly brought offline given the sensitivity the Hawai'i Island system has to changes in generation availability. Figure 12-20 shows the relationship between change in loss of load and change in cumulative firm capacity on Hawai'i Island for the Base Load scenario in 2030.

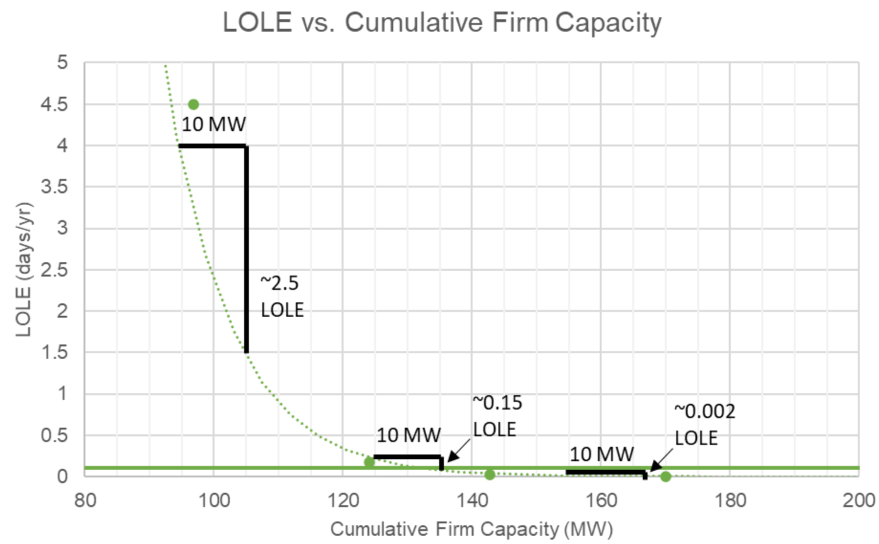


Figure 12-20. Hawai'i Island: relationship between change in loss of load and change in cumulative firm capacity (Base Load scenario, 2030)

The heat map in Figure 12-21 below shows when we expect unserved energy to occur and at what quantities for the scenario shown in Figure 12-20 above with a loss of load expectation around 0.1 day per year (High electricity demand scenario, remove 100 MW firm generation, add 140 MW hybrid solar). The quantities shown are an average of all 250 samples. With fewer firm units online, unserved energy is expected to occur during the early morning hours when firm resources are down for maintenance and during poor solar condition months like December.

Hours Beginning	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
1	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	0.0	0.1	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.1
3	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.1
4	0.0	0.1	0.0	0.1	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.2
5	0.0	0.1	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.5
6	0.0	0.1	0.1	0.1	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.9
7	0.1	0.1	0.0	0.1	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.2
8	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
10	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
20	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Max	
1 MW	
0 MW	
Min	

Figure 12-21. Hawai'i Island: remove 100 MW firm, add 140 MW hybrid solar heat map, Base Scenario 2030

Figure 12-22 assumes the 2035 High electricity demand forecast and the planned resource retirements through 2035. The 140 MW of hybrid solar from Stage 3 is assumed to be in service.

- In a High electricity demand scenario a loss of load expectation of 10 days per year is expected if no resources are added to the system.

When comparing the firm capacity graphs with the hybrid solar capacity graphs in Section 12.3.2.1, it's notable that when applied to the same resource portfolio, firm resources have a much larger impact on system reliability than a comparable amount of hybrid solar resources. The system is more sensitive to the addition or removal of firm resources than of hybrid solar resources.

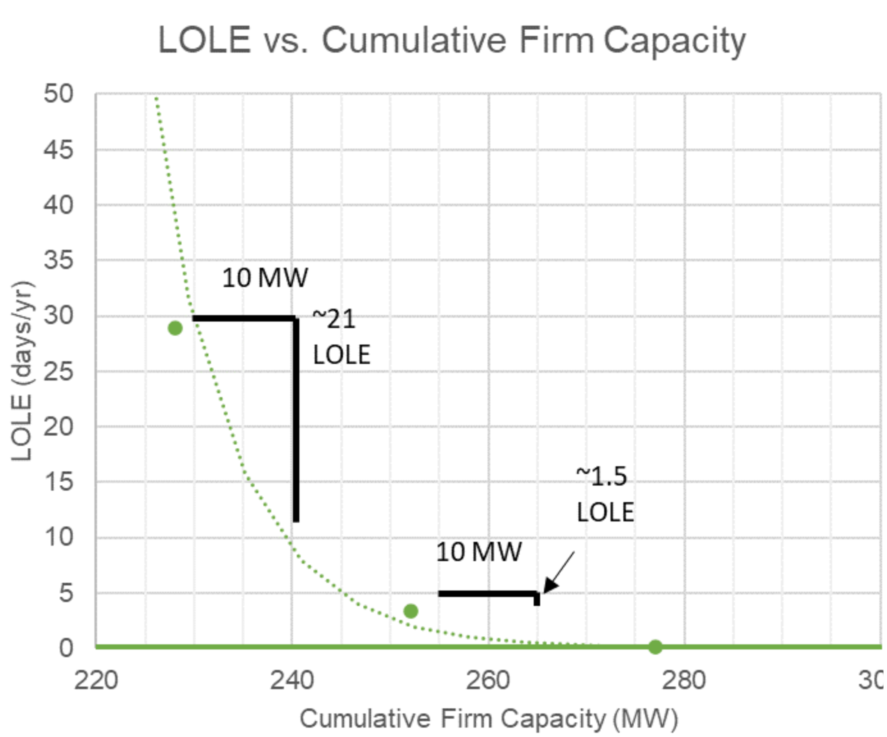


Figure 12-22. Hawai'i Island; loss of load vs. cumulative firm capacity (High Load scenario, 2035, linear y-axis)

The heat map in Figure 12-23 shows when we expect unserved energy to occur and at what quantities for the scenario shown in Figure 12-22 above with a loss of load expectation around 0.1 day per year (High electricity demand scenario, add 50 MW new firm generation, and no hybrid solar additions). The quantities shown are an average of all 250 samples. With fewer solar resources, unserved energy is expected to occur during the early morning and evening peak hours of hot weather, high load months like August.

Hours Beginning	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.0	0.0	0.0	0.1
1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0
2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0
6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0
7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0
8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0
15	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.0	0.0	0.0	0.0
16	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.0	0.0	0.0	0.0
17	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.0	0.0	0.0	0.0
18	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.9	0.0	0.0	0.0	0.4
19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.0	0.0	0.0	0.1
20	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5	0.0	0.0	0.0	0.0
21	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7	0.0	0.0	0.0	0.0
22	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.0	0.0	0.0	0.0
23	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.0	0.0	0.0	0.0

Max
1 MW
0 MW
Min

Figure 12-23. Hawai'i Island: add 50 MW firm, add 0 MW hybrid solar; expected unserved energy heat map (High Load scenario, 2035)

12.3.2.33-Day Energy Profile, High Unserved Energy Day

The energy profiles shown in Figure 12-24 and Figure 12-25 show the day from all 250 samples with the greatest unserved energy for the hybrid solar and firm generation sensitivities with loss of load expectation of approximately 0.1 day per year. This shows that even though the reliability target is met, unserved energy may still occur. For both scenarios, loss of load starts around midnight and continues through the morning hours. The system recovers by midday.

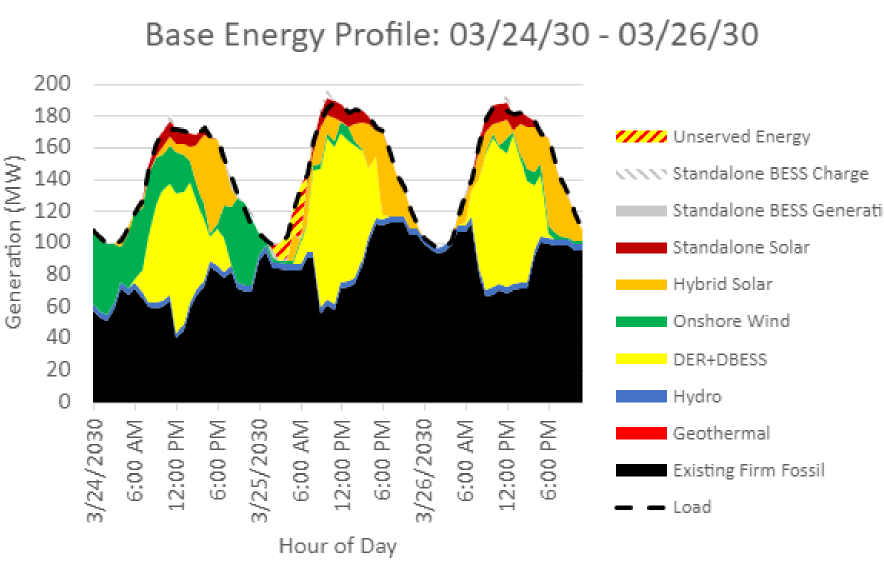


Figure 12-24. Hawai'i Island: Base Load scenario, remove 60 MW firm, add 0 MW hybrid solar heat map; detailed energy profile, 2030 high unserved energy day

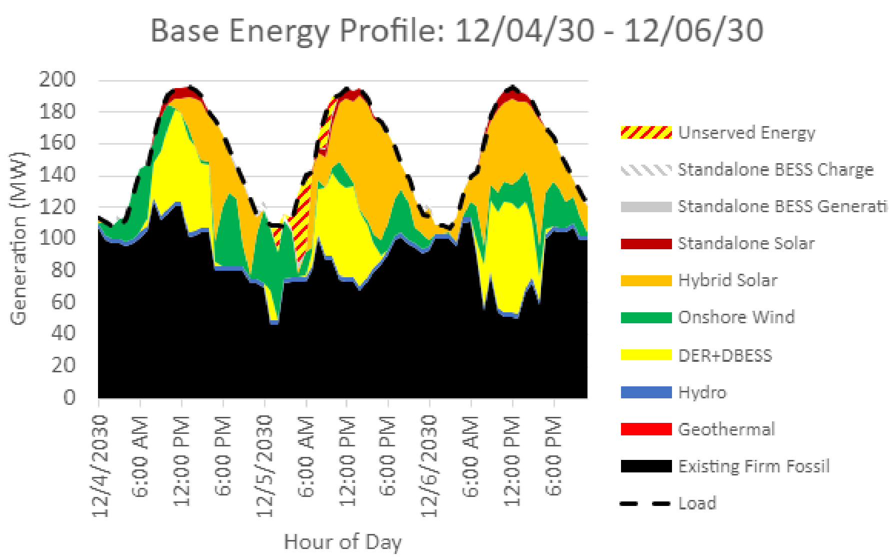


Figure 12-25. Hawai'i Island: Base Load scenario, remove 100 MW firm, add 140 MW hybrid solar; detailed energy profile, 2030 high unserved energy day

The energy profiles shown in Figure 12-26 and Figure 12-27 show the day out of all 250 samples with the greatest unserved energy for the hybrid solar and firm generation sensitivities in 2035 with loss of load expectation of approximately 0.1 day per year.

When adding only hybrid solar to the system as shown in Figure 12-26, loss of load starts around midnight and continues through the morning hours. The system recovers by midday.

When adding only firm generation resources to the system as shown in Figure 12-27, loss of load starts around midday and continues through the evening hours. The system recovers by midnight.

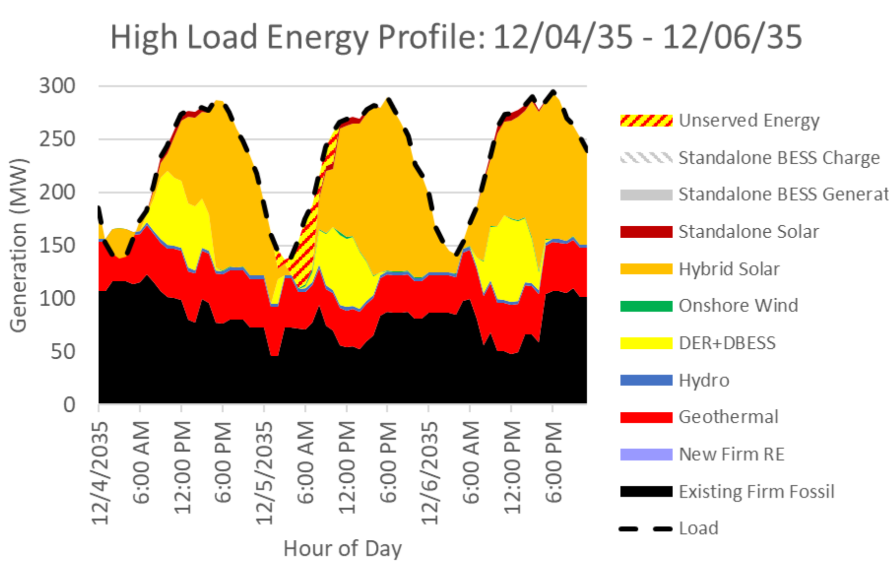


Figure 12-26. Hawai'i Island: High Load scenario, add 0 MW firm, add 420 MW hybrid solar; detailed energy profile, 2035 high unserved energy day

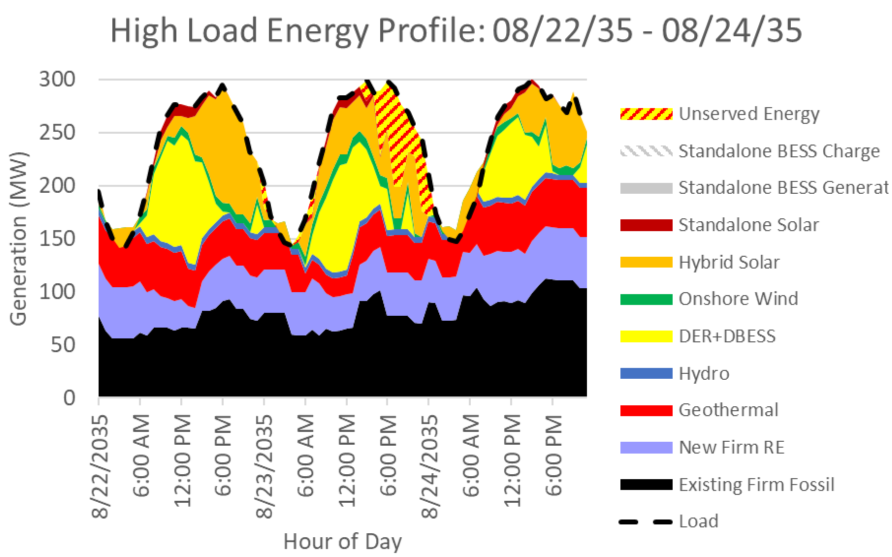


Figure 12-27. Hawai'i Island: High Load scenario, add 50 MW firm, add 0 MW hybrid solar; detailed energy profile, 2035 high unserved energy day

12.3.3 Maui

Uncertainty in forecasted electricity demand is a large source of risk for Maui. Section 8.4.2 shows how the planned Maui system meets reliability targets in 2030 and 2035 but requires additional resources in a High electricity demand scenario. This section shows how adding or removing resources from the Maui system affects reliability metrics.

12.3.3.1 Hybrid Solar Reliability Impact

As described earlier, the Maui Base scenario meets the loss of load expectation target of 0.1 day per year. However, if we do not acquire the hybrid solar sought in the Stage 3 procurement, the Maui system still meets the reliability target, in part because of the 40 MW of new firm generation.

To assess the reliability risk based on the amount of hybrid solar added in 2030, we removed the 40 MW firm generation sought in Stage 3 and incremented hybrid solar additions.

We show in Figure 12-28 the relationship between loss of load expectation and increments of hybrid solar. The figure shows that as we add more hybrid solar in 2030, the improvements to reliability diminish.

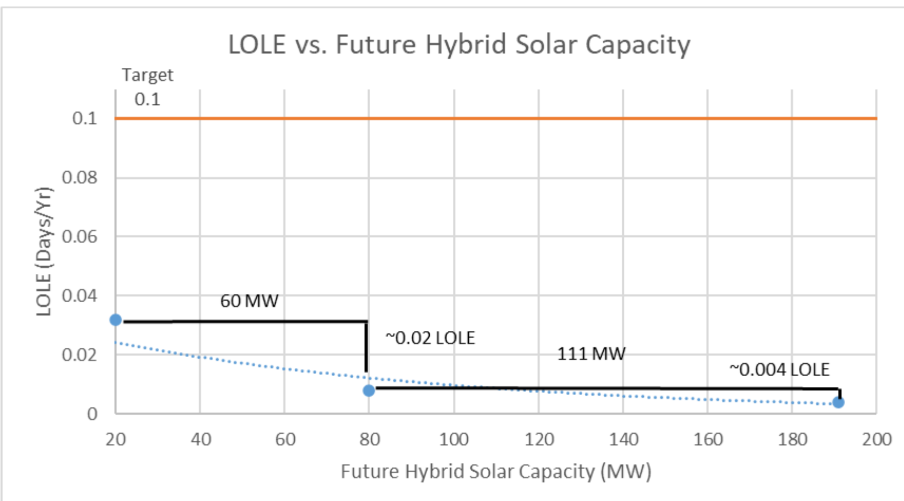


Figure 12-28. Maui: relationship between change in loss of load and change in future hybrid solar capacity, 2030

We performed a similar analysis in 2035. Unlike the 2030 hybrid solar sensitivity, which assumed the Base electricity demand forecast, this 2035 sensitivity assumed the High electricity demand forecast. With future uncertainties in EV adoption, we wanted to understand the reliability risks associated with load growth due to electrification of transportation.

In this sensitivity, we assume that the 40 MW of firm generation sought through Stage 3 is in service. Additional hybrid solar was then added to determine its impact on reliability in 2035. Figure 12-29 shows the relationship between loss of load expectation and incremental additions of hybrid solar. The figure demonstrates that as we add more hybrid solar in 2035, the improvements to reliability diminish. We also note that even with the acquisition of Stage 3 resources, we may not meet the 0.1 day/year loss of load target under the High electricity demand scenario.

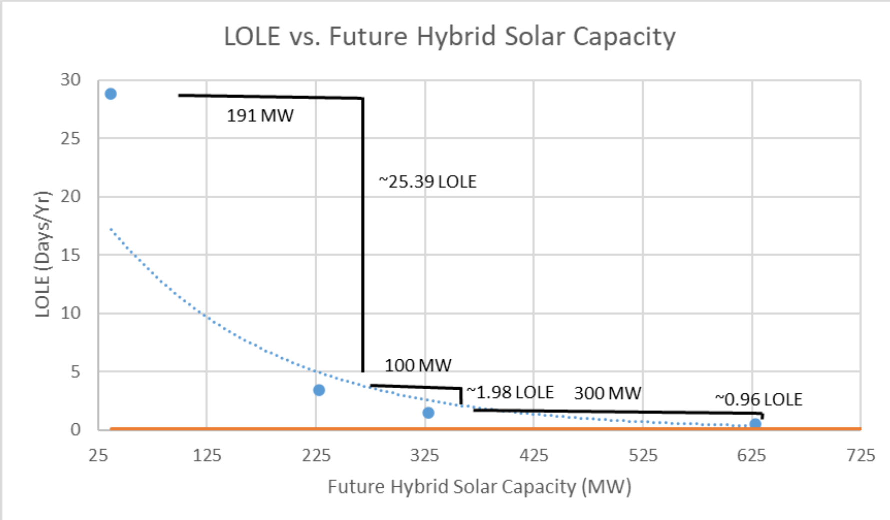


Figure 12-29. Maui: relationship between change in loss of load and change in future hybrid solar capacity (High Load scenario, 2035)

12.3.3.2Firm Generation Reliability Impact

We performed analysis to determine how loss of load expectation changes based on additions of firm generation. In this sensitivity, we assume that the 191 MW hybrid solar from the full Stage 3 target is in service.

Figure 12-30 shows that in 2030, with the Stage 3 hybrid solar, we may need approximately 18 MW of new firm generation to meet the 0.1 day/year loss of load expectation target. The figure shows that as more firm generation is added in 2030, the improvements to reliability diminish; however, in contrast to the hybrid solar sensitivity, smaller changes in firm capacity can significantly impact loss of load expectation. This further highlights the need to modernize our generation fleet with highly reliable generators.

Figure 12-31 shows when we expect unserved energy to occur and at what quantities when no future firm renewable from Stage 3 is assumed, from the scenario shown in Figure 12-30 with a loss of load expectation around 0.75 day per year. The quantities shown are an average of all 250 samples.

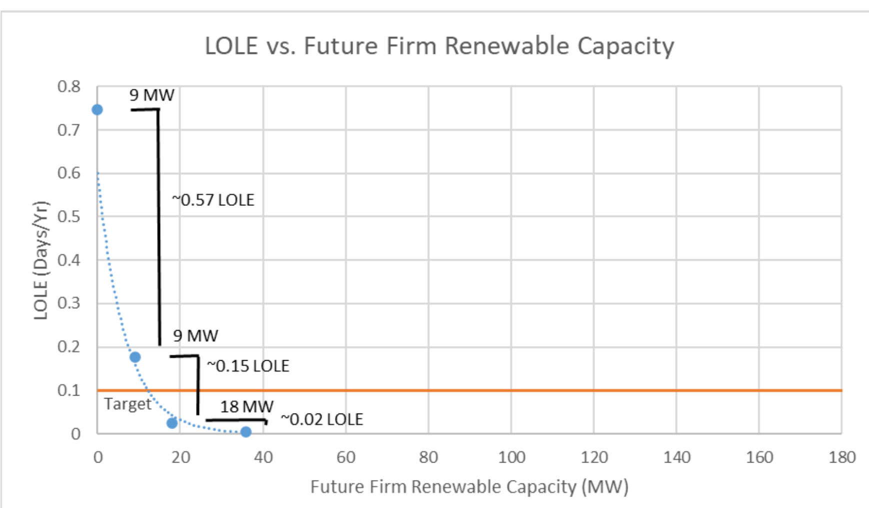


Figure 12-30. Maui: relationship between change in loss of load and change in future firm capacity, 2030

Hours Beginning	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	0.00	0.20	0.00	1.56	0.17	0.00	0.00	0.00	0.00	0.00	0.00	0.11
1	0.00	0.18	0.00	2.51	0.16	0.00	0.00	0.00	0.00	0.00	0.00	0.09
2	0.00	0.10	0.00	1.26	0.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.11	0.00	0.00	1.45	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.08
4	0.00	0.16	0.00	1.25	0.23	0.00	0.00	0.00	0.00	0.00	0.00	0.03
5	1.00	0.00	0.00	1.01	0.52	0.00	0.00	0.00	0.00	0.00	0.00	0.13
6	3.49	0.03	0.00	1.40	0.25	0.00	0.00	0.00	0.00	0.00	0.00	0.26
7	2.64	0.20	0.02	1.26	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.19
8	0.00	0.00	0.00	0.24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.16
9	0.00	0.00	0.00	0.06	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	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
16	0.00	0.00	0.00	0.22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.12
17	0.00	0.00	0.00	0.90	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.28
18	0.00	0.00	0.00	1.58	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.25
19	0.00	0.00	0.00	1.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08
20	0.00	0.00	0.00	1.99	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.50
21	0.00	0.00	0.00	1.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.15
22	0.00	0.00	0.00	2.51	0.14	0.00	0.00	0.00	0.00	0.00	0.00	0.23
23	0.00	0.00	0.00	1.33	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.18

Max
3.49 MW
0 MW
Min

Figure 12-31. Maui: no new firm, Base load, 2030

We also performed analysis to assess how reliability changes based on firm generation additions. Similar to the 2035 hybrid solar analysis, this 2035 firm generation analysis assumed the High electricity demand forecast.

Figure 12-32 shows the relationship between loss of load expectation and incremental firm generation additions in 2035. We would need close to 73 MW of new firm generation, to meet the 0.1 day/year target under a High electricity demand forecast.

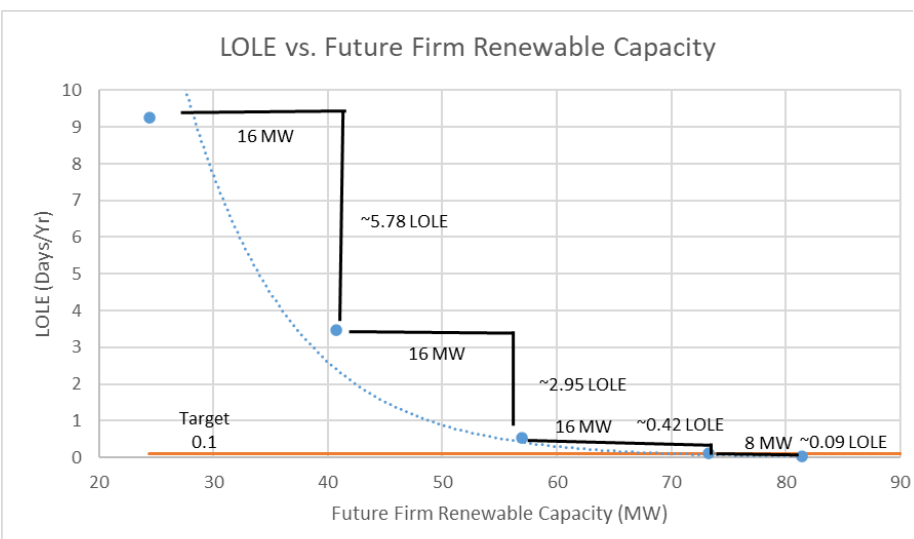


Figure 12-32. Maui: relationship between change in loss of load and change in future firm capacity (High Load scenario, 2035)

12.3.3.33-Day Energy Profile, High Unserved Energy Day

Figure 12-33 shows that even in the Base scenario where 0.1 day/year reliability is met, unserved energy may still occur. The overall trend shows that the existing thermal units ramp up in the evening and ramp down in the morning following the solar resources.

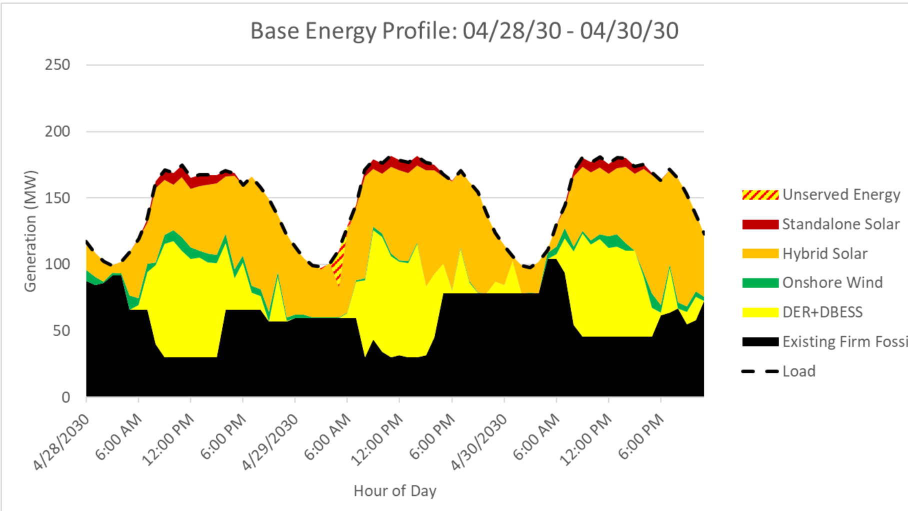


Figure 12-33. Maui: detailed energy profile, 2030 high unserved energy day

Figure 12-34 shows how in the Base scenario with the High load forecast, reliability is not met even with new resources being added. High amounts of unserved energy in the evening and morning hours still occur.

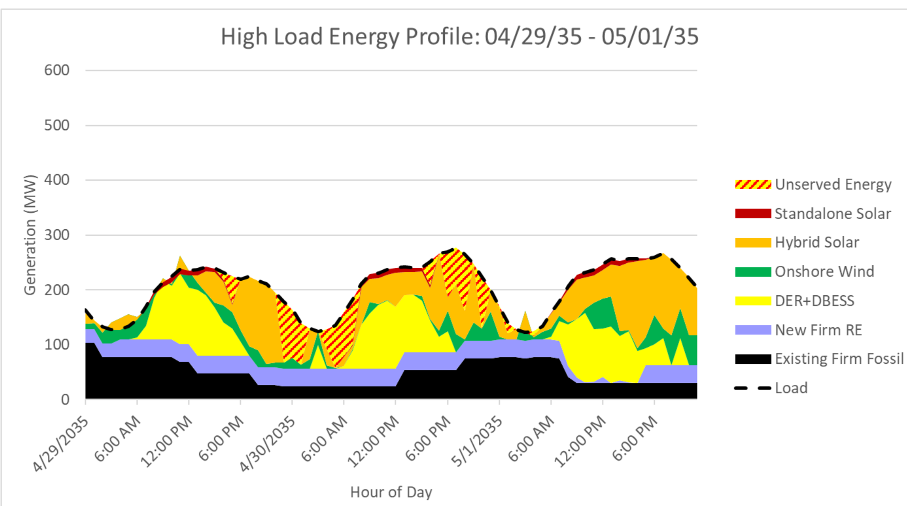


Figure 12-34. Maui: detailed energy profile, 2035 high unserved energy day

12.3.4 Moloka‘i

Uncertainty in forecasted electricity demand is a large source of risk for Moloka‘i. Section 8.5.2 shows how the planned Moloka‘i system meets reliability targets in 2030 and 2035. This section shows how adding or removing resources from the Moloka‘i system affects reliability metrics.

12.3.4.1Hybrid Solar Reliability Impact

We assessed the impact that hybrid solar has on reliability by assuming the Base scenario that includes 4.4 MW of firm generation. We added 3 MW increments of hybrid solar starting at 0 MW. Even with 12 MW of future hybrid solar, 4.4 MW of firm does not meet the loss of load target of 0.1 day per year. Figure 12-35 illustrates the difference in loss of load expectation benefit of 2 MW at different levels of hybrid solar. For example, going from 0 MW to 2 MW provides about 12 days/year loss of load expectation improvement versus a 0.6 day/year improvement going from 7 MW to 9 MW of hybrid solar. If we extrapolate the curve to hit a target of 0.1 day per year, it would take about 13 MW of hybrid solar capacity.

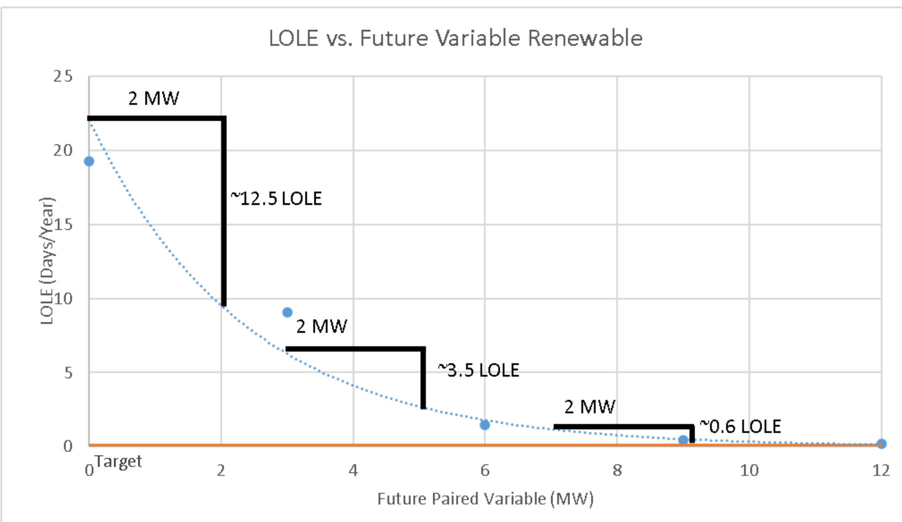


Figure 12-35. Moloka‘i: relationship between change in loss of load and change in future hybrid solar capacity (Base Load scenario, 2030)

The heat map in Figure 12-36 shows the expected unserved energy from 250 simulation samples. This shows that out of the 250 samples, the beginning of the year shows no unserved energy but during the later months, especially September, there is a higher possibility for unserved energy.

Hours Beginning	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.03	0.04	0.00	0.00	0.00
1	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.06	0.07	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.05	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.01	0.08	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.02	0.09	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.04	0.01	0.02	0.08	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.05	0.06	0.00	0.00	0.01
7	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.00	0.02	0.00	0.00	0.02
8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	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	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.03
18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.03
19	0.00	0.00	0.00	0.00	0.00	0.06	0.00	0.00	0.02	0.00	0.00	0.02
20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.03
21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.01
22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.02
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.01

Max	
0.1 MW	
0 MW	
Min	

Figure 12-36. Moloka'i: 4.4 MW firm, add 12 MW hybrid solar expected unserved energy heat map (Base Load scenario, 2030)

We also performed analysis in 2035 assuming a High electricity demand forecast to understand the impacts of accelerated EV adoption. Similar to the 2030 scenario we assume 4.4 MW of firm generation and hybrid solar additions in 3 MW increments starting at 0 MW.

Figure 12-37 illustrates the difference in loss of load expectation benefit of 2 MW at different levels of hybrid solar capacity. For example, going from 0 MW to 2 MW provides about 12 days/year loss of load expectation improvement versus a 0.9 day/year improvement going from 7 MW to 9 MW of hybrid solar. If we extrapolate the curve to hit a target of 0.1 day per year, it would take about 15 MW of hybrid solar capacity.

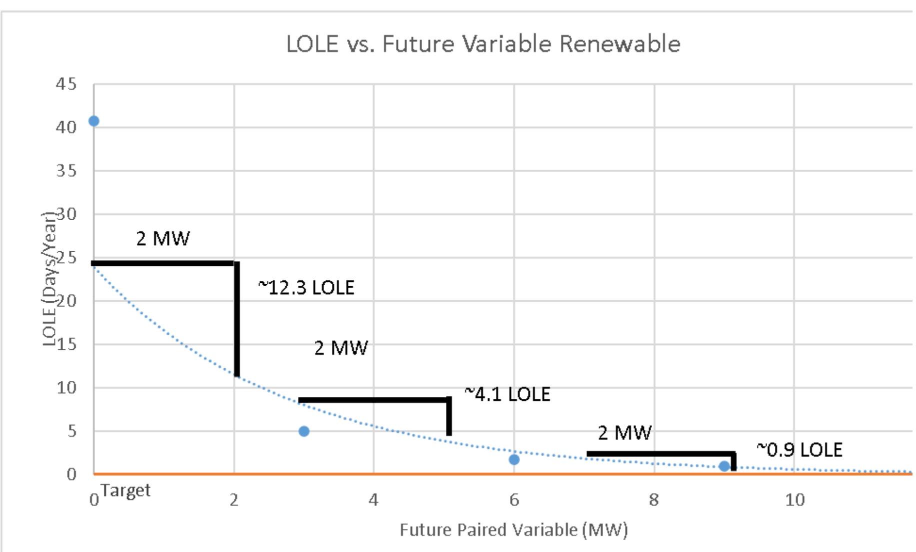


Figure 12-37. Moloka'i: relationship between change in loss of load and change in future hybrid solar capacity (Base Load scenario, 2035)

Figure 12-38 shows the expected unserved energy from 250 simulation samples. This shows that out of the 250 samples, the beginning of the year shows no unserved energy but during the later months, especially December, there is a higher possibility for unserved energy.

Hours Beginning	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.01	0.05	0.16
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.00	0.00	0.01	0.37
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.03	0.28
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.00	0.14	0.29
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.01	0.17	0.30
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.03	0.16	0.24
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.11	0.00	0.03	0.25	0.16
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.02	0.10	0.19
8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.04
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.01
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	0.01
16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.02
17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.01	0.12	0.07
18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.00	0.04	0.03	0.12
19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.00	0.01	0.18	0.12
20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.01	0.00	0.04
21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.05
22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.01	0.04	0.08
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.00	0.09	0.03	0.05

Max	
0.4 MW	
0 MW	
Min	

Figure 12-38. Moloka'i: 4.4 MW firm, add 12 MW hybrid solar expected unserved energy heat map (High Load scenario, 2035)

12.3.4.2Firm Generation Reliability Impact

To assess the impacts of firm generation, we assume 6 MW of hybrid solar and additions of firm generation in 2.2 MW increments starting at 2.2 MW. We based the 2.2 MW increments on existing generator sizes on Moloka'i.

Figure 12-39 illustrates the difference in reliability benefit of 1 MW at different levels of firm capacity. For example, going from 2.2 MW to 3.3 MW provides about 45 days/year loss of load expectation improvement versus a 2.5 day/year improvement going from 4 MW to 5 MW.

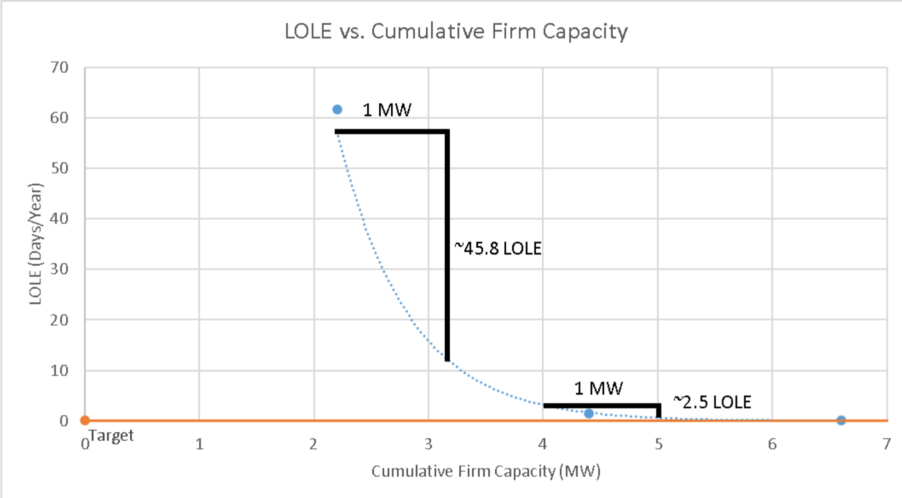


Figure 12-39. Moloka'i: relationship between change in loss of load and change in firm capacity (Base Load scenario, 2030)

Figure 12-40 shows the expected unserved energy from 250 simulation samples. This shows that for almost all the hours, the system does not show any unserved energy within the 250 samples.

Hours Beginning	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	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	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.01	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	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
18	0.00	0.00	0.00	0.00	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	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Max	
0 MW	
0 MW	
Min	

Figure 12-40. Moloka'i: 6.6 MW firm, 6 MW hybrid solar expected unserved energy heat map (Base Load scenario, 2030)

To assess the firm generation impact on reliability, we assumed that 6 MW of hybrid solar is in service with additions of firm generation in 2.2 MW increments starting at 2.2 MW. We based the 2.2 MW increments on existing generator sizes.

Figure 12-41 illustrates the difference in reliability benefit of 1 MW at different levels of firm capacity. For example, going from 2.2 MW to 3.3 MW provides about 39 days/year loss of load expectation improvement versus a 1.8 day/year improvement going from 4 MW to 5 MW of firm capacity.

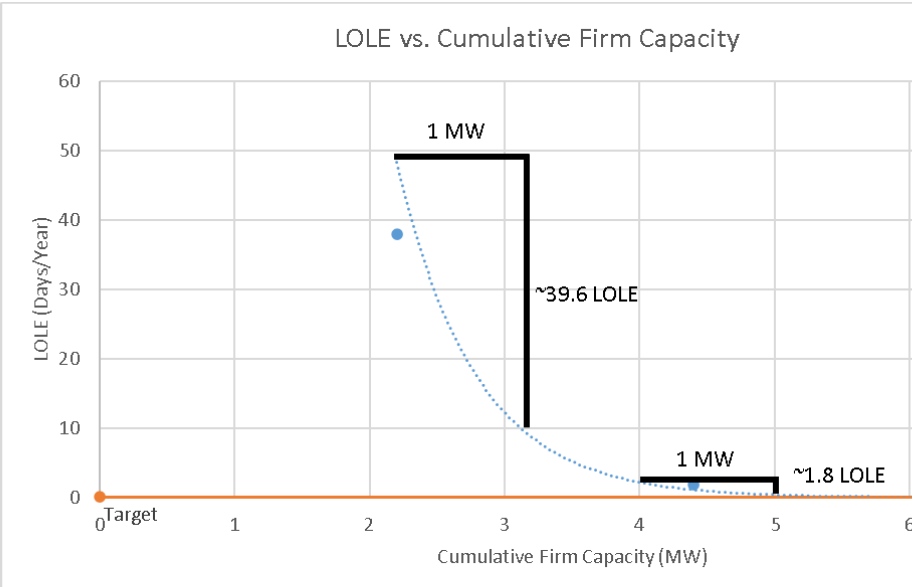


Figure 12-41. Moloka'i: relationship between change in loss of load and change in firm capacity (High Load scenario, 2035)

Figure 12-42 shows the expected unserved energy from 250 simulation samples. This shows that for almost all the hours, the system does not show any unserved energy within the 250 samples.

Hours Beginning	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	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	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.01	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	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
18	0.00	0.00	0.00	0.00	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	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Max
0 MW
0 MW
Min

Figure 12-42. Moloka'i: 6.6 MW firm, 6 MW hybrid solar expected unserved energy heat map (High Load scenario, 2035)

12.3.4.33-Day Energy Profile, High Unserved Energy Day

The energy profile shown in Figure 12-43 depicts the worst unserved energy day to illustrate what that day would look like. In this scenario, the firm generators are out of service and without them there is significant unserved energy in the late evening and early morning hours.

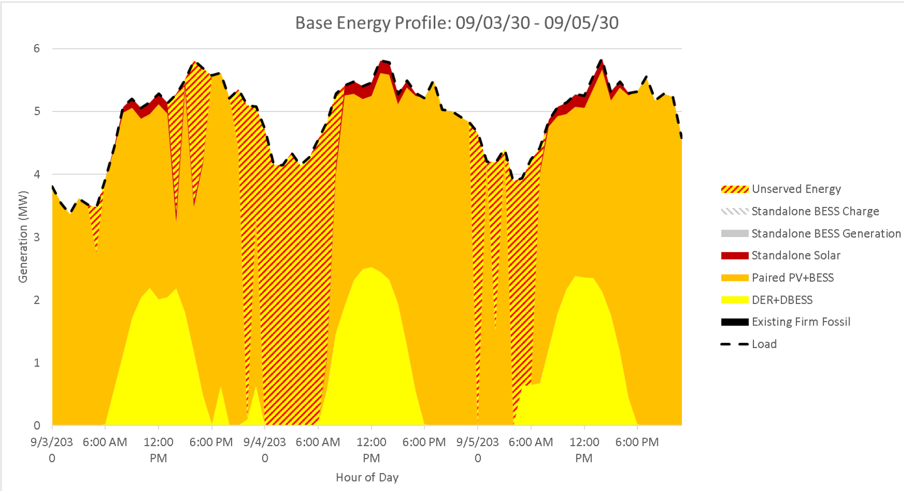


Figure 12-43. Moloka'i: 4.4 MW firm, add 12 MW hybrid solar; detailed energy profile, 2030 high unserved energy day

The energy profile shown in Figure 12-44 depicts the worst unserved energy day to illustrate what that day would look like. In this scenario, the firm generators are out of service and without them there is unserved energy in the late evening and early morning hours.

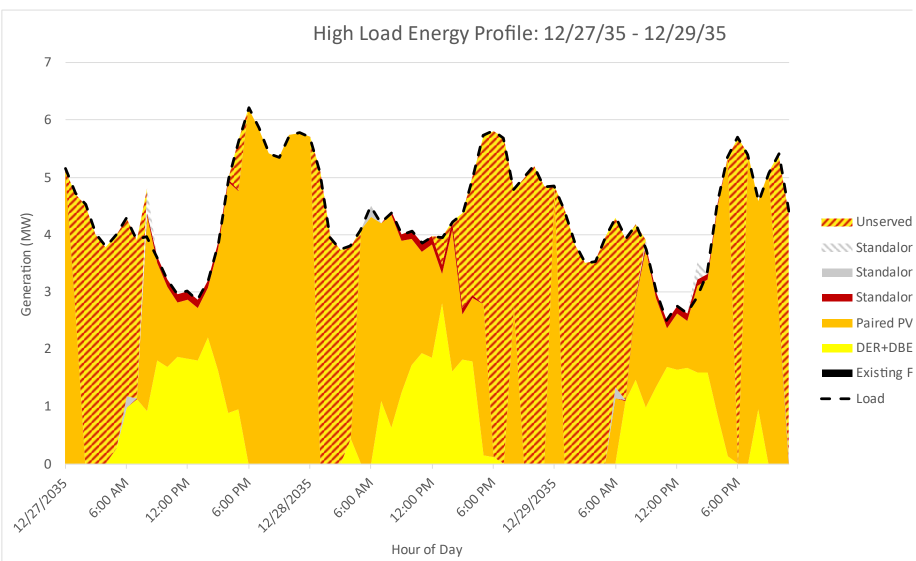


Figure 12-44. Moloka'i: 4.4 MW firm, add 12 MW hybrid solar; detailed energy profile, 2035 high unserved energy day

12.3.5 Lānaʻi

Uncertainty in forecasted electricity demand is a large source of risk for Lānaʻi. Section 8.6.2 shows how the planned Lānaʻi system meets reliability targets in 2030 and 2035. This section shows how adding or removing resources from the Lānaʻi system affects reliability metrics.

12.3.5.1Hybrid Solar Reliability Impacts

We assessed reliability impacts to hybrid solar additions on Lānaʻi in 2030. To determine the sensitivity of the loss of load expectation based on the amount of variable renewable generation added in 2030, we removed future hybrid solar and 2 MW of existing firm generation. We then varied the amount of hybrid solar to see how reliability changed.

As shown in Figure 12-45, in 2030, with 8 MW of firm generation, we need approximately 10 MW of hybrid solar to meet the 0.1 day/year loss of load expectation target. Shown below is the relationship between loss of load expectation and hybrid solar additions in 2030. The figure shows that as we add more hybrid solar, the improvements to reliability diminish.

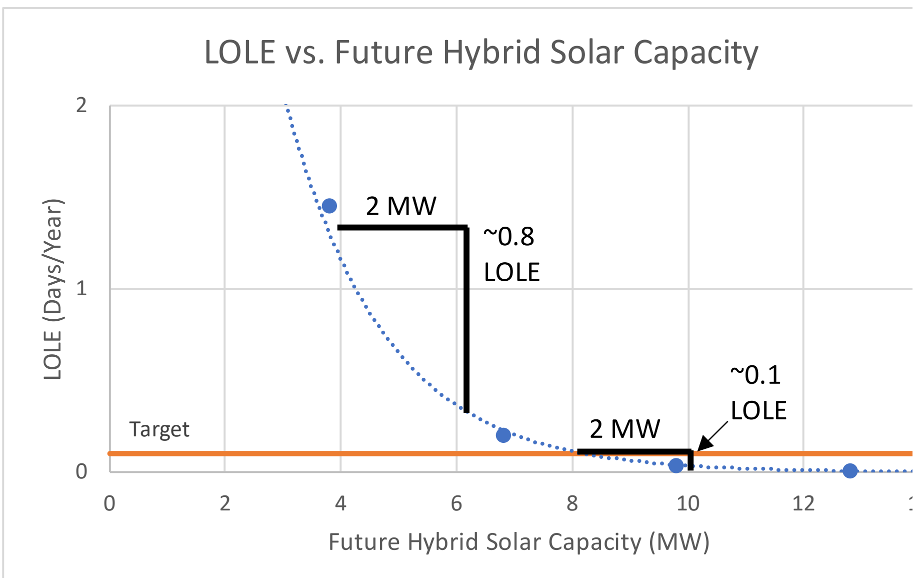


Figure 12-45. Lānaʻi: relationship between change in loss of load and change in hybrid solar (Base Load scenario, 2030)

Figure 12-46 presents the unserved energy based on the month and hour of the system with 8 MW of firm generation and 10 MW of hybrid solar. Unserved energy could be seen in the morning hours of October to December.

Hours Beginning	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	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	0.01	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	0.01
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
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	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00
18	0.00	0.00	0.00	0.00	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	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Max	
0.03 MW	
0 MW	
Min	

Figure 12-46. Lāna'i: 8 MW firm 10 MW hybrid solar expected unserved energy heat map (Base Load scenario, 2030)

To determine the sensitivity of the loss of load expectation based on the amount of hybrid solar added under the 2035 High electricity demand forecast, we removed the future hybrid solar and 2 MW of existing firm (see Figure 12-47). We then varied the amount of hybrid solar to see how reliability changed. The 2035 High electricity demand forecast is not drastically higher than the 2030 Base electricity demand forecast; therefore, the loss of load expectations between 2030 and 2035 are similar.

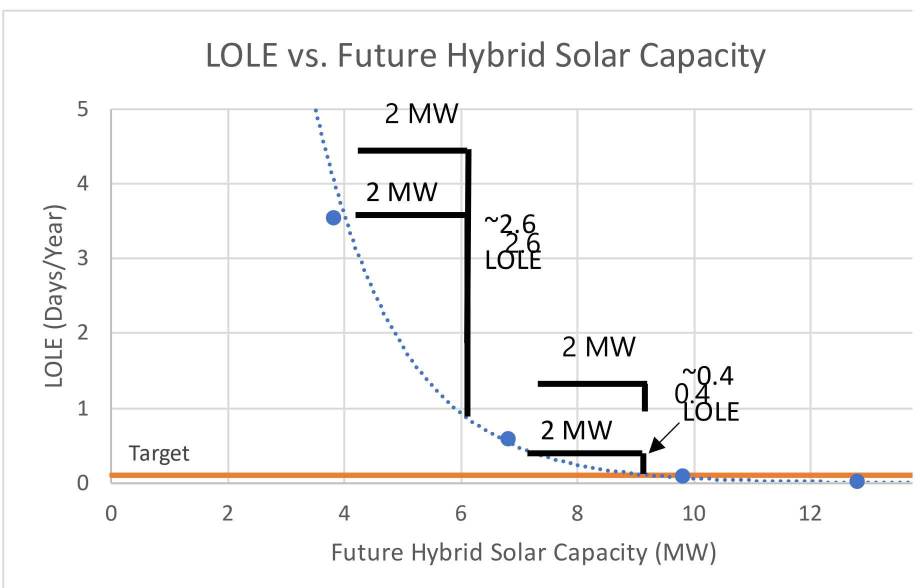


Figure 12-47. Lāna'i: relationship between change in loss of load and change in hybrid solar (High Load scenario, 2035)

Figure 12-48 presents the unserved energy based on the month and hour of the system with 8 MW of firm generation and 10 MW of hybrid solar. We observe unserved energy mostly from October to December.

Hours Beginning	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.01
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.02
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.01
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.02
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.01	0.01	0.01
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.02	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01
8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
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	0.01
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	0.01
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	0.01	0.00	0.01
16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00
17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.02
18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00
19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	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	0.01
21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Max	
0.03 MW	
0 MW	
Min	

Figure 12-48. Lāna'i: 8 MW firm, add 10 MW hybrid solar expected unserved energy heat map (High Load scenario, 2035)

12.3.5.2Firm Generation Reliability Impacts

We also performed analysis to analyze how the loss of load expectation changes based on the amount of existing firm generation in 2030. In this sensitivity, we assume that 16 MW from the past CBRE RFP is in service.

In 2030, 6 MW of firm generation is sufficient to meet the 0.1 day/year loss of load expectation target. Figure 12-49 shows the relationship between loss of load expectation and firm generation. The impact to loss of load expectation decreases as the amount of firm generation increases.

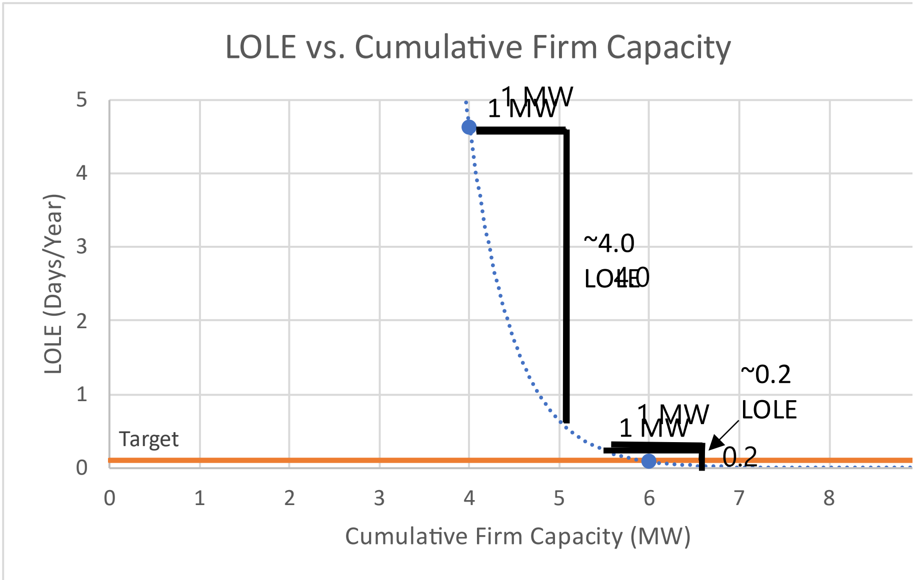


Figure 12-49. Lāna'i: relationship between change in loss of load and change in firm capacity (Base Load scenario, 2030)

Figure 12-50 presents the unserved energy based on the month and hour. Most of the unserved energy is observed in the morning and evening hours.

Hours Beginning	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	0.00	0.00	0.00	0.00	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	0.01
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01
4	0.00	0.00	0.00	0.00	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	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.01	0.01
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.01	0.01
8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.02	0.01
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	0.01	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	0.01	0.01
17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.02	0.01
18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.01	0.02
19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
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	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Max	
0.02 MW	
0 MW	
Min	

Figure 12-50. Lāna'i: 6 MW firm, add 16 MW hybrid solar expected unserved energy heat map (Base Load scenario, 2030)

We also analyzed the relationship between loss of load expectation and the amount of existing firm generation in the 2035 High electricity demand forecast. In this sensitivity, we assumed that 16 MW of hybrid solar is in service.

As shown in Figure 12-51, in 2035, we will need more than 6 MW of firm generation to meet the 0.1 day/year target. The figure shows the relationship between the loss of load expectation and firm generation.

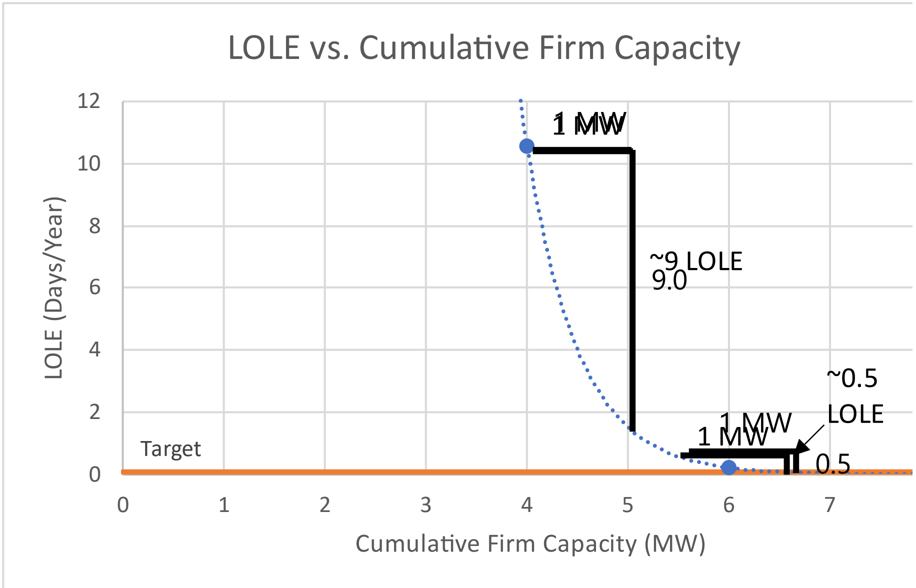


Figure 12-51. Lāna'i: relationship between change in loss of load and change in firm capacity (High Load scenario, 2035)

Figure 12-52 presents the unserved energy based on the month and hour. Most of the unserved energy is observed in the morning and evening hours.

Hours Beginning	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.02
1	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.01	0.01
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.02	0.00	0.02
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.01	0.01	0.02
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.03
5	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.01	0.02	0.01	0.01	0.03
6	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.01	0.02	0.00	0.01	0.03
7	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.02	0.01	0.00	0.03	0.06
8	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.02	0.00	0.01	0.01	0.02
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
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	0.01	0.00	0.01	0.02	0.00
16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.02	0.02	0.00
17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.00	0.02	0.02	0.00
18	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.05	0.00	0.05	0.02	0.00
19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.00	0.05	0.00	0.00
20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.00	0.00	0.00
21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.00	0.01	0.00
22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.00	0.01	0.00
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00

Max
0.06 MW
0 MW
Min

Figure 12-52. Lāna'i: 6 MW firm, add 16 MW hybrid solar expected unserved energy heat map (High Load scenario, 2035)

12.3.5.33-Day Energy Profile, High Unserved Energy Day

The results shown above are the average of the 250 simulation samples. Figure 12-53 shows a sample in the 2030 Base scenario where unserved energy is experienced in the early morning hours.

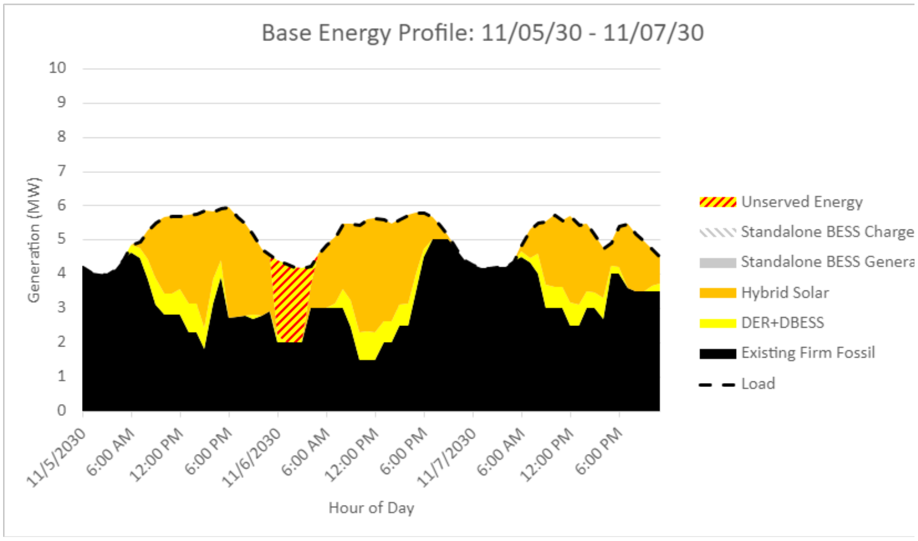


Figure 12-53. Lāna'i: 8 MW firm, add 10 MW hybrid solar; detailed energy profile, 2030 high unserved energy day

Figure 12-54 shows a sample in the 2035 High Load scenario where unserved energy is experienced in the early morning hours and mid-afternoon.

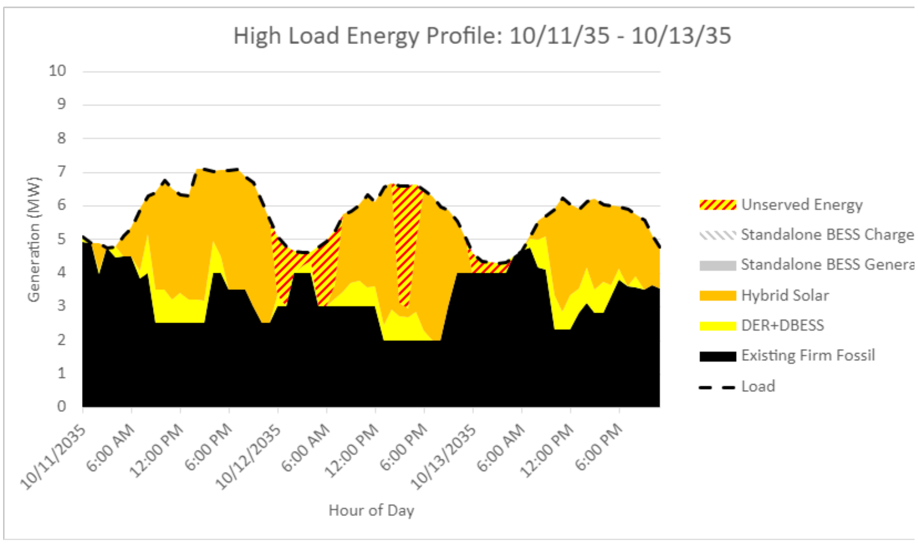


Figure 12-54. Lāna'i: 8 MW firm, add 10 MW hybrid solar; detailed energy profile, 2035 high unserved energy day