Appendix B:

Forecasts, Assumptions and Modeling Methods

1. Forecasts and Assumptions

1.1 Load Forecast and Methodology

The load forecast is one of the many assumptions that the resource planners use in their models to stress test the various plans under varying conditions. Multiple scenarios and sensitivities were developed to plan around uncertainties surrounding adoption of behind-the-meter technologies, which ultimately drive the load forecast and peak demand. Additional sensitivities were also identified in the resource planning stage.

Forecasts were developed for the five islands beginning 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 sales forecast and adjusting layers – energy efficiency, distributed energy resources, and electrification of transportation, and time-of-use rate load shift).

The underlying sales forecast is driven 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 (EE), distributed energy resources (DER), primarily photovoltaic systems with and without storage (*i.e.,* batteries), and electrification of transportation (light duty electric vehicles (EV) and electric buses (eBus), collectively "EoT") were layered onto the underlying sales outlook to develop the sales forecast at the customer level. Load shifting in response to time-of-use rates (TOU) was also included as a forecast layer. Since the load shift was assumed to be net zero (i.e. load reductions during the peak period are offset by load increases during other time periods), there is impact to the peak forecasts, but no impact to the sales forecasts. An illustration of the components that contribute to the customer sales forecast is shown in Figure B-1.

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

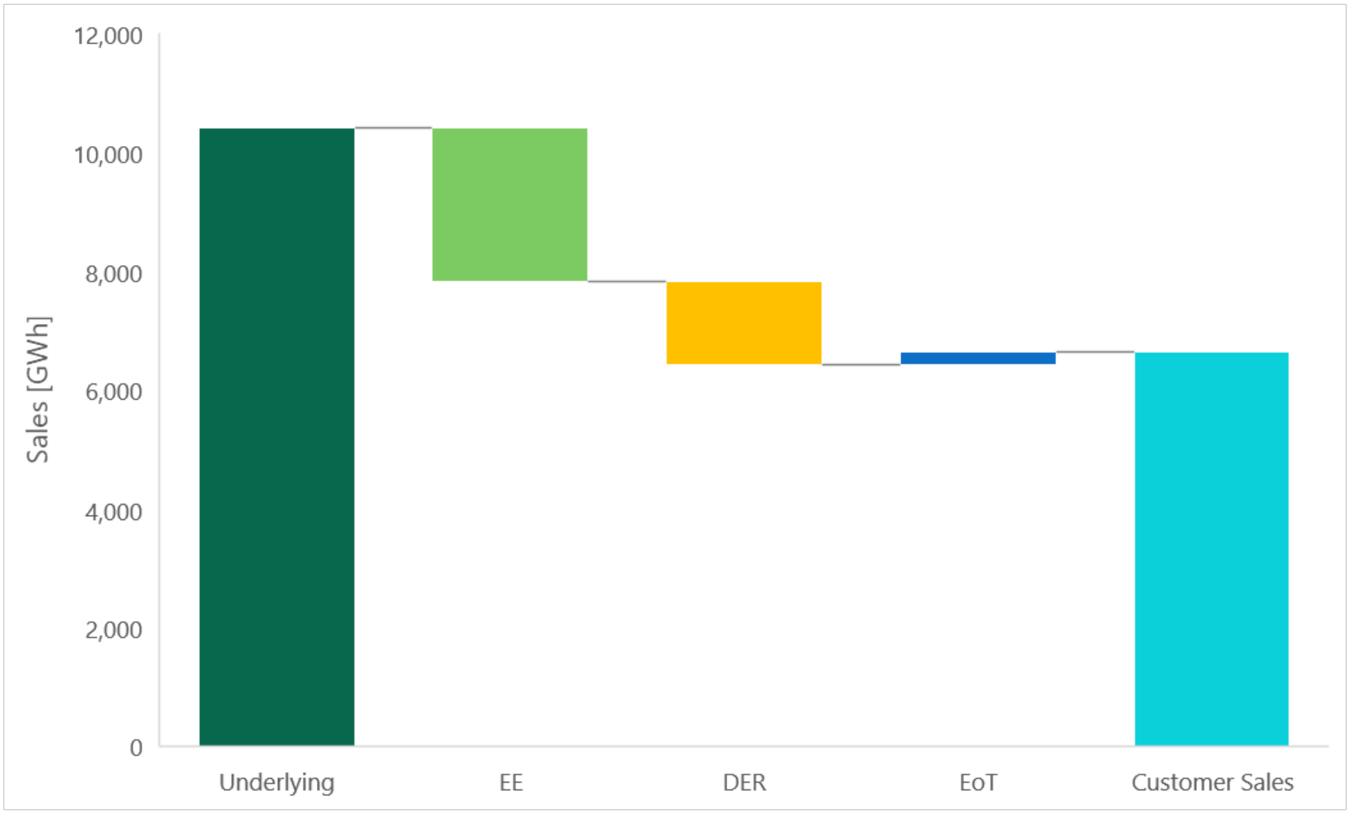

Figure B-1. Oahu Customer Sales Forecast by Layers[2]

The residential and commercial sectors are forecasted separately as each sector's electricity usage has been found to be related to a different set of drivers as described in the approved March 2022 Inputs and Assumptions filing. To summarize, historical recorded sales used in econometric models are adjusted to remove sales impact of DER, EE and EoT, which are treated as separate layers. Input data sources for developing the underlying sales forecast include economic drivers, weather variables, electricity price and historical data from the Company, as shown in Table B-1 below.

Table B-1. Input Data Sources for Underlying Forecast

Source	Data
University of Hawaii Economic Research Organization	Real personal income Resident population Non-farm jobs Visitor arrivals
NOAA – Honolulu, Kahului, Hilo and Kona Airports	Cooling degree days Dewpoint Temperature Rainfall

[2] Time-of-Use layer is not shown due to the assumption that customer sales [kWh] during peak load hours we shifted to other hours of the day resulting in net-zero change to sales.

Itron, Inc.	Commercial energy intensity trend for Pacific Region for non-heating/cooling end uses.
Hawaiian Electric	Recorded kWh sales Recorded customer counts Large load adjustments Real electricity price

The underlying sales forecast was based on a combination of multiple models and methods (i.e., certain models/methods are more appropriate for near-term time horizons and others for long-term trends). Methods for the underlying layer include:

- Market analysis: A ground up forecast evaluating individual customers (particularly large commercial customers), projects, and events that may merit a specific carve out if significant, i.e., new large projects or loss of large loads.
- Customer service: An analysis of recent trends in customer counts, sales and use per customer and applies knowledge of local conditions such as construction activity, state of the visitor industry, trends in weather including impacts of storms and volcanic eruptions.
- Trending models: Uses historical data series to project future sales or customer counts. Works well when historical data series has identifiable patterns and future trends aren't expected to vary from the past.
- Econometric models: Relates sales or customers' use of electricity to macroeconomic variables such as personal income, jobs, population, and visitor arrivals as well as other variables such as temperature, humidity or electricity price. Econometric models may also incorporate time series parameters such as lagged dependent variables or an autoregressive term. The quantification of the impact of changes in the economic and other variables on use is the strength of these models.
  The econometric model is specified in the following form:

$$Y = \beta 0 + \sum_{i=1}^{n} (\beta i \; x \; Xi)$$

where the dependent variable, Y, is kWh sales or use per customer and is related to the independent (explanatory) variables, X*i*, which represent economic or other variables.

Variables β*i* represent the regression model coefficients. The constant variable β*0* represents the Y-intercept.

1.2 DER Forecasts

The DER layer includes impacts of behind the meter PV and battery energy storage systems as well as known projects for other technologies (e.g., wind). This forecast adjustment estimated new additions of DER capacity in each month by island, rate class and program, and projected the resulting monthly sales impact from these additions. The DER adoption forecasts included stakeholder suggestions to develop several sensitivities including a high and low forecast for the bookend scenarios.

Future DER capacity modeling considered two time horizons:

- Near term (approximately next three years) reflects the current pace of incoming applications and executed agreements, existing program (NEM, NEM+, SIA, CGS, GSP, CSS and ISE)[3] subscription level and caps, feedback from the Companies' program administrators, PV system installers, customer input and any studies or upgrades being done to address short-term hurdles (e.g. circuit study, equipment upgrades) that affect the installation pace; and
- Longer term forecast, which is model-based as the detailed application information is not available.

To extend the DER forecast from the short-term through the full planning period, an economic choice model using payback considers a set of assumptions such as the installed cost of PV and battery, incentives, electricity price, program structure that affect the economic benefit to the customer which is the primary driver of their decision to adopt the system.

Storage size assumptions for each island and rate class were optimized based on return on investment for an average customer. By modeling average customer's optimal pairing size, the amount of forecasted storage was appropriately captured for the overall rate class as customers with larger storage requirements offset those with smaller or no storage requirements. DER customers store excess generation during the midday that is then used to reduce their load (and additionally export to the grid in the case of future export programs such as Scheduled Dispatch) during the peak period daily. As a result, DER customers are shifting their load in a manner consistent with proposed TOU rates and no additional load shift would be expected in response to TOU rates.

Monthly DER capacity factors for each island were used to convert installed capacity to customer energy reductions. The monthly capacity factors recognize the variations in solar irradiance throughout the year rather than using a single average annual capacity factor to reflect monthly variations more accurately in the energy production of DER systems. A degradation factor of 0.5% per year[4] was applied to the sales impacts to recognize that the DER system's performance degrades over time.

To develop a high and low DER forecast, a number of factors were considered based on stakeholder feedback. As a result, Table B-2 summarizes the assumptions used to develop the DER forecasts.

Table B-2. Summary of assumptions used to develop DER forecast sensitivities

Input	No State ITC	Low	Base	High
Synopsis	Revised lower DER uptake below market forecast	Market Forecast based on self-consumption	Revised uptake based on DER docket proposals (The Company), include EDRP (Oahu, Maui),	Revised uptake based on DER docket proposals (DER Parties), include EDRP, updated resource costs, expanded addressable market

[3] Existing programs include Net Energy Metering, Net Energy Metering Plus, Standard Interconnection Agreement, Customer Grid Supply, Customer Grid Supply Plus, Customer Self Supply, and Interim Smart Export.

[4] Median degradation rate from NREL "Photovoltaic Degradation Rates – An Analytical Review", D.C. Jordan and S.R. Kurz, 2012, http://www.nrel.gov/docs/fy12osti/51664.pdf

			expanded addressable market	
Cost Projections	NREL ATB - Moderate	NREL ATB - Moderate	NREL ATB - Moderate	NREL ATB Advanced
Federal Tax Credits	Dec 2020 COVID-19 Relief	Dec 2020 COVID-19 Relief	Dec 2020 COVID-19 Relief	10-year extension
State Tax Credits	0%	Increased 2021 to 35%	Increased 2021 to 35%	Increased 2021 to 35%
Includes EDR Program	No	No	Yes (Oahu, Maui)	Yes
Long Term Upfront Incentives	None	None	$250/kW (Oahu, Maui)	$500/kW
Long Term Export Program	NA	NA	Standard DER Tariff (All Islands) with Scheduled Dispatch (Oahu, Maui)	Smart Export+ with Scheduled Dispatch
Addressable Residential Market	Single Family/2-4 Unit Multi- Family/Owner Occupied/Consumption Threshold	Single Family/2-4 Unit Multi- Family/Owner Occupied/Consumption Threshold	Single Family/2-4 Unit Multi- Family/Owner Occupied/Consumption Threshold	Single Family/2-49 Unit Multi- Family/Consumption Threshold
Addressable Commercial Market	Public or Private Owned/<6 stories/Consumption Thresholds	Public or Private Owned/<6 stories/Consumption Thresholds	Public or Private Owned/<6 stories/Consumption Thresholds	Public or Private Owned/<6 stories/Consumption Thresholds/Expand Sch-P Customer Pool to 100%
Add-Ons	NEM+	NEM+	Sch-R NEM above minimum bill customers from 2021-2023 (Oahu, Maui), NEM+[5]	Sch-R NEM customers from 2021-forward

For incentives, the Base forecast assumed the following for Federal and State investment tax credits shown in Table B-3 and Table B-4.

Table B-3. Federal Tax Incentive Rate Schedule

Class	2019	2020	2021	2022	2023	2024+
Residential	30%	26%	26%	26%	22%	0%
Commercial	30%	26%	26%	26%	22%	10%

Table B-4. State Tax Incentive Rate Schedule

2019	2020	2021	2022	2023	2024	2025	2026	2027+
35%	35%	35%	25%	25%	20%	20%	20%	15%

- State cap on residential PV-only systems: $5,000 in all years
- State cap on residential PV+storage systems: $5,000 in 2019-2021, $10,000 in 2022-forward

[5] Customers participating in NEM+ is included in the Base case scenario for all islands, but only from 2024-forward for Oahu and Maui because Schedule-R NEM customers were re-introduced in the customer pool for 2021-2023.

One of the key drivers in the long-term DER forecast is the addressable market, including customers that can add-on to existing systems. The addressable market for residential customers included single family and multi-family homes with a maximum of four units that were owner occupied and with a high enough energy consumption to utilize at least a 3 kW PV system, as shown in Table B-5. Historically, only 15-20% of residential PV installations have been below 3 kW. From a practical perspective, customers with low consumption are less likely to make an investment in rooftop PV. Smaller systems are also less cost-effective due to fixed portions of the installation and material costs being spread out over smaller total capacity and savings potential.

Existing NEM customers who were not reaching a minimum bill were added to the addressable market from 2021 through 2023 for O'ahu and Maui, as shown in Table B-6. In addition, comments from stakeholders indicated that there might be DER customers who only install a battery. However, others may increase their PV capacity to capture the total value of tax credits. Considering these comments, future retrofits for NEM customers assumed both an addition of a battery system, 5 kW/13.5 kWh, and an increase in PV capacity, 5kW[6].

Table B-5. Addressable Market for Residential Customers

Island	Percent of Schedule R Customers	Average PV System Size (KW)	Average Storage Size (KWH)
O'ahu	37%	7.0	15.5
Hawai'i Island	41%	6.0	11.0
Maui	43%	7.0	15.0
Lāna'i	24%	4.0	9.0
Moloka'i	30%	4.0	12.0

Table B-6. NEM Customers Added to Residential Addressable Market

Island	Percent of Schedule-R NEM Customers	Average PV System Size (KW)	Average Storage Size (KWH)
O'ahu	85%	5	13.5
Maui	71%	5	13.5

For commercial customers, public and private building ownership was considered in defining the addressable marketand structures greater than six stories were excluded. Similar to residential customers, small and medium commercial consumption needed to be above a set energy usage threshold. Commercial thresholds were established using rate class customers' previous 12-months usage, historical PV installation data, and business types. PV and non-PV customer segmentation by business type. Distributions for total energy usage[7] were created for PV customers. Usage at the lower 1/8th quantile was used as the threshold for business types that had five or more customers who already installed PV. The default thresholds of 500kWh for Schedule G and 5,000 kWh for Schedule J are

[6] Order No. 37816 permits existing PV customers to add up to 5 kW of additional PV generation capacity.

[7] Total usage is the sum of the previous 12-months sales plus the sum of the previous 12-months estimated PV generation.

used for business types with less than five existing customers with PV already installed. The resulting addressable market for the commercial sector can be seen in Table B-7 through Table B-10.

Table B-7. Addressable Market for Commercial Customers

Island	Percent of Schedule G Customers	Percent of Schedule J Customers	Percent of Schedule P Customers
O'ahu	37%	53%	78%
Hawai'i	35%	68%	44%
Maui	41%	63%	68%

Table B-8. Addressable Market, Average PV System Size, and Average Storage Size for Schedule G Customers

Island	Percent of Schedule G Customers	Average PV System Size (KW)	Average Storage Size (KWH)
O'ahu	37%	7.0	12.5
Hawai'i	35%	5.5	9.5
Maui	41%	7.0	14.5

Table B-9. Addressable Market, Average PV System Size, and Average Storage Size for Schedule J Customers

Island	Percent of Schedule J Customers	Average PV System Size (KW)	Average Storage Size (KWH)
O'ahu	53%	76.0	40.0
Hawai'i	68%	64.0	15.0
Maui	63%	59.0	45.0

Table B-10. Addressable Market, Average PV System Size, and Average Storage Size for Schedule P Customers

Island	Percent of Schedule P Customers	Average PV System Size (KW)	Average Storage Size (KWH)
O'ahu	78%	330.0	0.0
Hawai'i	44%	64.0	0.0
Maui	68%	330.0	0.0

1.3 Time-of-Use Rates

We evaluated and included Time-of-Use (TOU) load shifting impact for non-DER customers and non-EV load into the load forecast. Generally, TOU rates are thought to be a mechanism to encourage customers to modify their consumption patterns (ex. shift evening peak usage to other hours of the day) by reacting to different energy price signals. Stakeholders stated that residential TOU load shift scenarios should be included in the IGP base forecast and bookend forecasts even if impacts are relatively small because it is likely that TOU rates will be implemented. Based on the proposal presented and stakeholder input, assumptions in Table B-11 were used to develop TOU load shift scenarios for residential customers.

Table B-11. 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

One of the key components of the Advanced Rate Design ("ARD") discussed in the DER docket includes the implementation of TOU rates, including mandatory TOU for DER customers. Consistent with Advanced Rate Design ("ARD") discussions, each customer that adopts DER (solar paired with storage) and/or electric vehicles under managed charging scenarios is effectively shaping their consumption to operate consistent with a TOU rate. For example, DER customers would charge their energy storage system with rooftop solar during the day and discharge the system in the evening. This load shifting is captured in the DER forecasts battery storage profiles. Since these DER customers are shifting their load in a manner consistent with proposed TOU rates, no additional load shift would be expected in response to TOU rates. The managed charging forecast profiles reflect customers charging electric vehicles during the day in response to TOU rates. On October 31, 2022, the Commission issued PUC Order No. 38680 established future TOU rates will include three daily time periods with a 1:2:3 price ratio. While specific rates, charges, and timing may deviate from the Base assumptions, the forecast sensitivities adequately capture the potential load shift due to TOU rates.

We assumed new DER customers would be defaulted into a Three-Part TOU rate that includes a $3/kW monthly demand charge. Referencing the Company's Bill Comparison of 2017 TY and Proposed Three-Part TOU Rates under the ARD Track Initial Proposal[8], a 300 kWh monthly usage and 3.336 kW peak residential customer's monthly bill, including the demand charge, would be an estimated $5.86 higher under the proposed TOU rate compared to the 2017 TY rates. For a 600 kWh monthly usage and 3.336 kW peak residential customer, their estimated monthly bill would be $3.69 lower under the ARD rates compared to 2017 TY rates. This small difference would not affect the economic choice model DER uptake forecast in either direction for the average customer with the assumed average PV and battery system size. Stakeholders commented that prospective DER customers looking toward purchasing a future EV may be dissuaded from adopting DER because of the potential impact of a large demand charge from vehicle charging. While a demand increase would lead to a higher demand charge under the Company's proposed ARD rates, DER uptake would not necessarily be decreased under this scenario. The DER uptake model assumes a system size for PV and storage based on average customer usage. Introduction of an EV load would require adjusting the assumed PV and storage system size to account for the planned load increase, which ultimately adjusts the payback period.

1.3.1 Literature Review

Key takeaways from the Companies' literature review, including California studies[9], and estimated load shift for residential customers were presented to the STWG on September 23, 2021.

On October 1, 2021, the Consumer Advocate ("CA") submitted comments on the TOU analysis presented in the September 23, 2021 STWG. The CA made suggestions as potential input to development of commercial TOU forecasts.

- Review three commercial TOU studies sited by the CA for consideration that may provide relevant information to estimate commercial TOU impacts.
- Review historical data for the Companies' commercial customers enrolled in TOU.
- If no "reasonable Hawaii-based or comparable studies" provide sufficient data to support a forecast, consider a pilot to provide understanding of the potential impacts.
- The CA notes that they do not suggest delay or suspension of the IGP process to pursue this path.

In response to the CA's comments, we investigated additional studies on TOU and customer response summarized below.

[8] *See* Hawaiian Electric's Advanced Rate Design Initial Proposal filed on December 17, 2020 in Docket No. 2019-0323, Instituting a Proceeding to Investigate Distributed Energy Resource Policies pertaining to the Hawaiian Electric Companies.

[9] Sacramento Municipal Utility District (2014), SmartPricing Options for Final Evaluation, research-SmartPricing-options-final-evaluation.ashx (smud.org)

In Aigner and Hirschberg (1985),[10] the summer period time-of-use energy (kWh) pricing subsection of the study may be comparable to the ARD proposals, although considered with caution due to changes in customer loads and efficiency that have occurred since the time of the study. The authors' conclusion from their analysis of covariance is, "For the time-of-use energy rates, no perceptible shifting behavior is predicted in either season."[11] The elasticity for the TOU energy rates in both seasons resulting from their econometric analysis also suggests there is no price responsive load shifting because the result "indicates that an increase in peak-to-off peak price ratio will cause an increase in the proportion of peak kWh consumption."[12] The authors note several limitations of the study that may have impacted the results and speculate that customers will shift load if the price signal is large enough. However, the actual statistical results of the study support the conclusion that the IGP load forecasts are reasonable as proposed without a commercial TOU load shift layer.

The Qui et al. (2018)[13] study was conducted in the summer in Phoenix, Arizona. It is characterized by the authors as a study that "reveals how business customers respond to TOU pricing under relatively extreme weather conditions – summer in the Phoenix metropolitan area, where the average high temperature is above 100 degrees and air conditioner (AC) usage in the summer peak hours is a major portion of the system load."[14] The conditions of the study are not comparable to conditions in Hawaii.

The California Statewide Pricing Pilot (SPP)[15] studied small commercial and industrial (C&I) customers' demand response to time variant rates in the Southern California Edison service territory. The C&I peak period was from noon to 6pm on weekdays. The observed peak period reductions were highly dependent upon smart thermostats as an enabling technology for customers with central air conditioning.[16] The results for the two-part TOU treatment group varied significantly across the two years of the study and the authors state that results of that treatment group, "should be viewed cautiously, however, in light of the small sample size and significant variation in the underlying model coefficients across summers."[17] The peak period in the Companies' final ARD proposal is 5pm-10pm and the lowest rates would be during the proposed midday period of 9am-5pm. Because of the differences in the time periods of when the highest (and lowest) rates occur and the significant dependence of the California SPP results on enabling technology, the California SPP results are not directly applicable to commercial customers under ARD rate proposals in the Companies' service territory.

[10] Aigner, D. and Hirschberg, J. (1985). Commercial/Industrial Customer Response to Time-of-Use Electricity Prices: Some Experimental Results. RAND Journal of Economics, 16(3), 341-355.

[11] At 349

[12] At 352

[13] Qiu, Y., Kirkeide, L., and Wang, Yi. (2018). Effects of Voluntary Time-of-Use Pricing on Summer Electricity Usage of Business Customers. Environ Resource Econ 69, 417-440.

[14] At 418

[15] Charles River Associates (2005). Impact Evaluation of the California Statewide Pricing Pilot. *See* https://www.smartgrid.gov/document/impact_evaluation_california_statewide_pricing_pilot

[16] At 119-120

[17] At 13

Current participation rates in commercial TOU rates is extremely low: 16 customers on O'ahu, 2 customers on Maui island, 2 customers on Hawai'i island, all on either Schedule TOU-G or Schedule TOU-J. There is insufficient customer data to guide or project the response from commercial TOU customers. In addition, the existing commercial TOU rates, as with all existing TOU rate options, are voluntary, while the proposed TOU rates in Advanced Rate Design are opt-out default rates. Based on commercial customers' historically low participation in TOU rates in the Companies' service territory and the results of referenced studies, it is unlikely that implementing an opt-out commercial TOU rate in and of itself will result in load shifting.

The Company will evaluate the response of residential and commercial customers that are assigned in the ARD TOU Roll Up Period study[18]. This information will be used to inform forecasts in future IGP cycles.

1.4 Energy Efficiency

The energy efficiency 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 Hawai'i Public Utilities Commission.[19] The market potential study considered customer segmentation, technologies and measures, building codes and appliance standards as well as the progress towards achieving the Energy Efficiency Portfolio Standards. The study included technical, economic, and achievable energy efficiency potentials which allowed the development of different EE forecast sensitivities.

An achievable Business As Usual (BAU) energy efficiency potential forecast by island and sector represented savings from realistic customer adoption of energy efficiency measures through future interventions that were similar in nature to existing interventions. In addition to the BAU forecast, AEG provided a Codes and Standards (C&S) forecast and an Achievable – High forecast. The C&S forecast included the impacts of new codes and standards set to take effect in future years that were known and codified by June 2020. The Achievable - High potential forecast assumed higher levels of savings and participation through expanded programs, new codes and standards, and market transformation.

For the High Load Bookend scenario, the EE Low sensitivity forecasts were updated to include C&S savings for all islands. To represent the potential for lower EE savings, the EE Low sensitivity reduced the programmatic Business-As-Usual component by 25%. Additionally, the EE Freeze sensitivity was updated to include future C&S savings, aligning with the EE Base, Low, and High sensitivities. No modifications were made to Business-As-Usual component of the EE Freeze sensitivity. Shown in Table B-12 is a revised summary of the EE forecast sensitivities.

[18] PUC Order No. 38680 issued October 31, 2022 under Docket 2019-0323, Instituting a Proceeding to Investigate Distributed Energy Resource Policies Pertaining to The Hawaiian Electric Companies

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

The impacts from AEG were derived at an annualized level and included free riders which reflected savings for all measures as if they were all installed in January and provided savings for the whole year. The annualized impacts were adjusted to reflect ramping in of measures throughout the year to arrive at energy efficiency impacts by month for each forecasted year. For simplicity, the installations were assumed to be evenly distributed throughout the year.

Table B-12. Summary of Energy Efficiency Forecast Sensitivities

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

1.4.1 Energy Efficiency Supply Curve Bundles

Energy efficiency supply curve bundles were developed to determine the optimal amount of energy efficiency measures compared to the assumed forecasted energy efficiency using the results of the Hawaii Statewide market potential study ("MPS") that AEG performed on behalf of the Public Utilities Commission. In the modeling, energy efficiency was treated either as a reduction to load within the energy efficiency sales layer, or included in the supply curve bundles as a supply side resource.

1.4.1.1 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 energy efficiency potential, referred to as "achievable technical," before applying any screens for cost-effectiveness.

Developing Achievable Technical Potential

Achievable technical potential is a subset of technical potential, accounting for likely customer adoption of energy efficiency measures without consideration of cost-effectiveness. To develop the achievable technical potential, the customer participation rates from the "Future Achievable – High" case from the MPS, which account for market barriers, customer awareness and attitudes, program maturity, and other factors that may affect market penetration of energy efficiency measures.

Differences from the Hawaii statewide potential study

Figure B-2 illustrates the levels of potential assessed in the MPS. Striped layers show impacts that are contained in the baseline forecast and therefore not part of the energy efficiency supply curves. These categories include naturally occurring efficiency, codes & standards impacts, and the lingering effects of past program achievement.

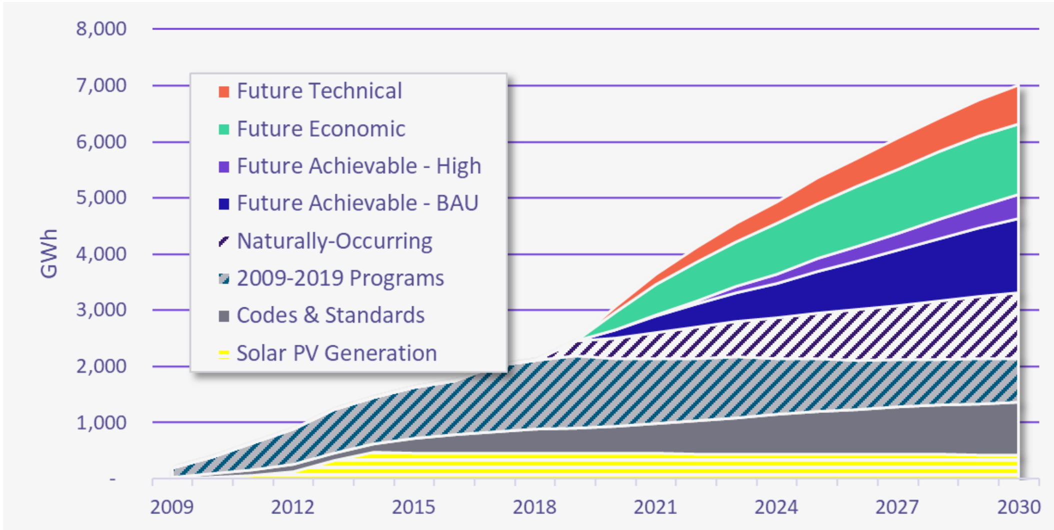

Figure B-2. Cumulative Persistent Energy Savings through 2030, EEPS Perspective[20]

Because the achievable technical potential used to develop the supply curves does not consider cost-effectiveness, it is not the same as any of the levels of potential shown in Figure B-2. Rather, the amount of available achievable technical potential would fall between the "Future Technical" and "Future Achievable – High" potentials.

Peak Impacts

Each energy efficiency measure has an island-specific load shape, which was created during the potential study process. By taking the annual savings calculated from the MPS 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 6:00 PM and 8:00 PM) and are calculated as the average impacts during such hours.

Figure B-3 shows the average impacts of all measures within each classification using Oahu 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.

[20] See State of Hawaii Market Potential Study, Executive Summary page iv, Figure ES-3 (https://puc.hawaii.gov/wp-content/uploads/2021/02/Hawaii-2020-Market-Potential-Study-Final-Report.pdf)

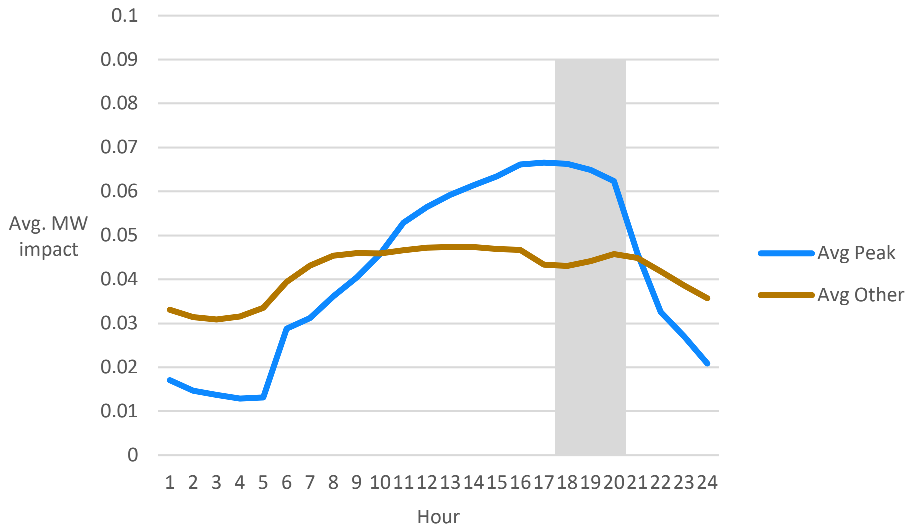

Figure B-3. Averaged Weekday Impacts by Measure Classification, Cumulative in 2030 (Peak vs Other, Oahu)

Cost-Effectiveness

The next consideration for bundling measures was the cost of savings. Although the levelized cost of conserved energy ($/MWh), which annualizes costs across each measure's lifetime, is one means of understanding resource costs, grouping solely based on energy saved may not allow the model to efficiently target measures with higher benefits due to contributions to peak reduction. Because the benefit-cost ratios (using the Total Resource Cost test perspective) from the MPS captured both energy and capacity benefits, these ratios represent a convenient metric for bundling measures considering both cost and value. Table B-13 shows the ranges used for bundle classification, which serve to separate measures that are highly cost effective (A) from borderline cost effective and not cost effective measures (B and C) to very non-cost-effective measures (D) to avoid them skewing the overall cost of the more attractive groups.

Table B-13. Benefit-Cost Ratio Ranges Assigned to Bundle Groups

Bundle	Benefit-Cost Ratio Range
A	>1.2
B	1.0 - <1.2
C	0.8 - <1.0
D	< 0.8

It is important to note that many of the measures in group A could have absolute costs ($/MWh) that are *higher* than measures in group B or C. In those cases, the greater benefit of peak-focused resources offsets the costs in the MPS methodology. Depending on how the shape of bundles meets the RESOLVE model's needs, it might choose lower absolute costs first, which could produce differences between the

RESOLVE model selections and the MPS. This flexibility is an expected feature of the chosen methodology.

Bundle Costs

To allow energy efficiency resources to compete against other supply side resources, the model is provided a levelized cost of conserved energy (LCOE) for each model based on the measure-level costs from the Statewide MPS, in $ per MWh. This is a Total Resource Cost **net** value which includes not only the installed cost of the measure, but net effects from non-energy impacts, O&M costs or savings, and possible avoided replacement costs, annualized over the life of the measure. Because non-energy impacts are netted out of the cost, it is possible for a measure to have a negative LCOE if the benefits are greater than the cost of the measure. Each bundle's LCOE is calculated as the savings-weighted average of the LCOEs of the measures within the bundle. To further inform the planning process, the peak MW impact of each bundle was also noted (as calculated from the annual energy and load shape) and a value of $/MW was derived by multiplying the levelized cost of energy ($/MWh) by the annual savings (MWh) and dividing by the associated peak savings (MW).

1.4.1.2 Analysis Results

Figure B-4 below 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, due to equipment turnover in the potential study modeling. Note that these annual savings values do not include re-installation 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 re-acquisition, 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 MPS. The modeled potential without re-acquisitions is a conservative estimate to avoid overstating potential.

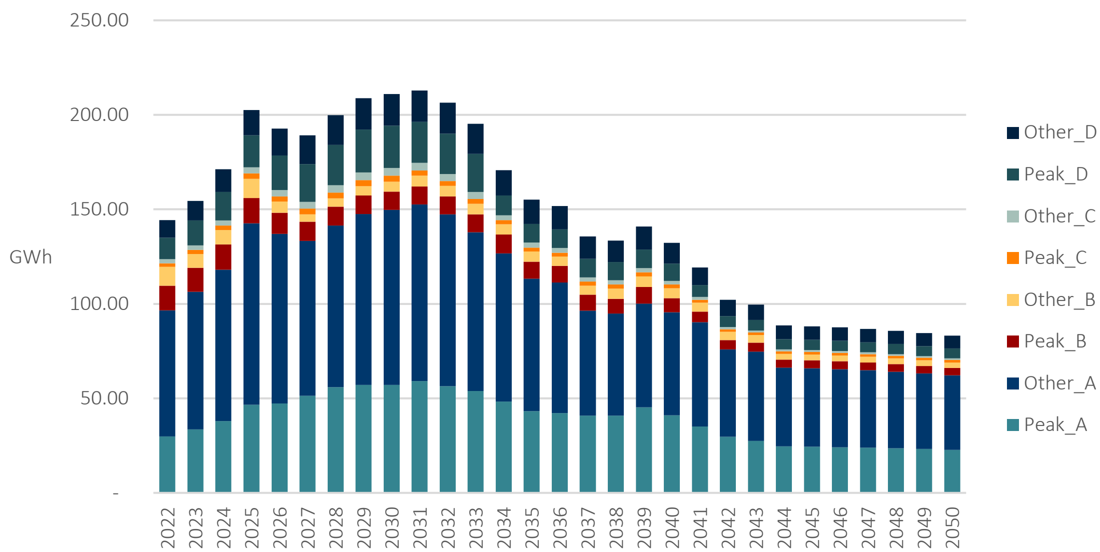

Figure B-4. Incremental Annual Energy Savings Potential (Achievable Technical) by Measure Bundle (All Islands Combined)

Table B-14 and Figure B-5 below show the cumulative energy savings by end use for each bundle. The savings here represent the total Achievable Technical Potential in 2045 from the MPS.[21]

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.

Table B-14. Technical Potential Energy Savings (GWh) by Measure Grouping and End Use (All Islands Combined)

	Peak					Other			
End Use	A	B	C	D		A	B	C	D
Cooling	17.5	2.3	0.5	2.9		5.3	0.1	0.2	1.2
Ventilation	2.0	0.2	0.3	0.4		2.8	0.1	0.3	0.8
Water Heating	2.1	0.2	0.1	0.2		11.5	2.2	0.0	0.4
Interior Lighting	0.2	1.1	0.1	0.4		11.2	0.0	0.0	0.2
Exterior Lighting	0.1	0.1	0.0	0.0		1.0	0.0	0.0	0.3
Res Appliances	0.1	0.0	0.2	1.0		0.5	0.5	0.1	2.6
Com Refrigeration	0.2	0.0	0.0	0.2		1.9	0.0	0.2	1.0
Electronics	0.2	0.0	0.0	0.0		0.1	0.0	0.0	0.0
Food Preparation	0.0	0.0	-	-		0.2	0.0	-	0.0
Miscellaneous	0.2	0.0	0.1	0.0		5.0	0.1	0.2	0.3
Total	22.7	3.9	1.3	5.2		39.4	3.0	0.9	6.7

[21] The Statewide MPS study period only ran to 2045. Annual potential from 2046-2050 was calculated based on the year-over-year trend from 2040-2045.

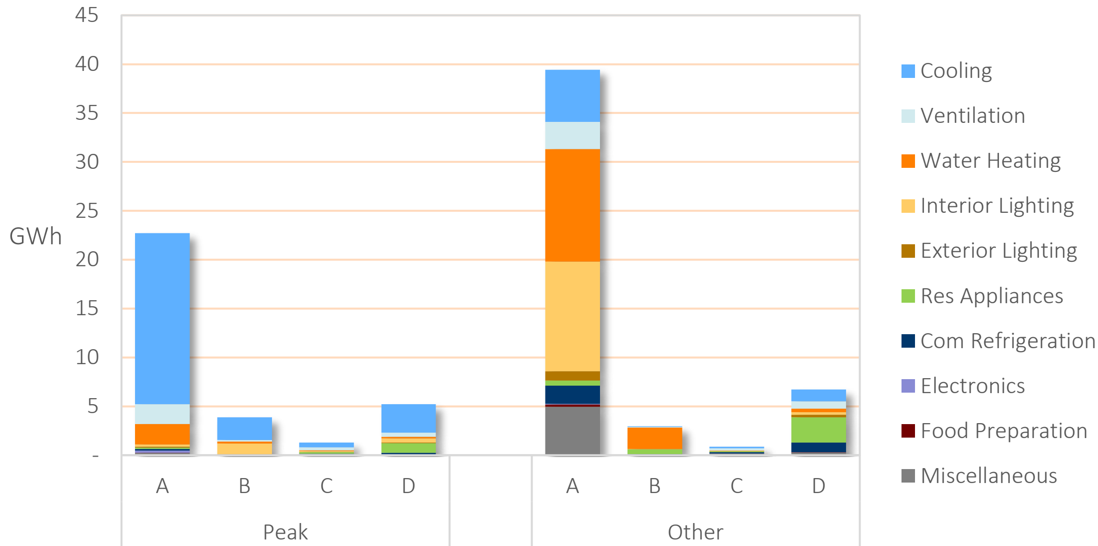

Figure B-5. Achievable Technical Energy Savings (GWh) by Measure Grouping and End Use (All Islands Combined)

As noted in Order No. 38482, the energy efficiency supply curves must be revisited to adjust the peak window used in the bundling process to 5-10 p.m. Also, clear explanation of the bundling process and rationale must be provided to clarify for peak bundles, whether the majority of savings are coincident with system peak or the measure's maximum savings occur during peak hours.

In the O'ahu charts below, there is some shifting of the supply curve shapes for the adjusted peak window but generally, the shapes are the same.

- Peak bundles retain the same profiles where their savings steadily increase and concentrate impacts at or near the peak window
- Other bundles do not have a concentrated impact at the peak window and instead have oscillating savings above and below the flat shape (black reference line).
- During the peak period, the Other bundles also have a smaller peak savings contribution compared to the Peak bundles.
- The clear difference in shape observed between the measures bundled as Peak and Other was a factor in assessing the appropriateness of the bundles because it is more informative to the resource plan development to know if certain energy efficiency shapes are preferred by the models.

Based on these results, it does not appear that the adjusted peak window makes a material impact on the bundle shape and the energy efficiency supply curves do not need to be revised.

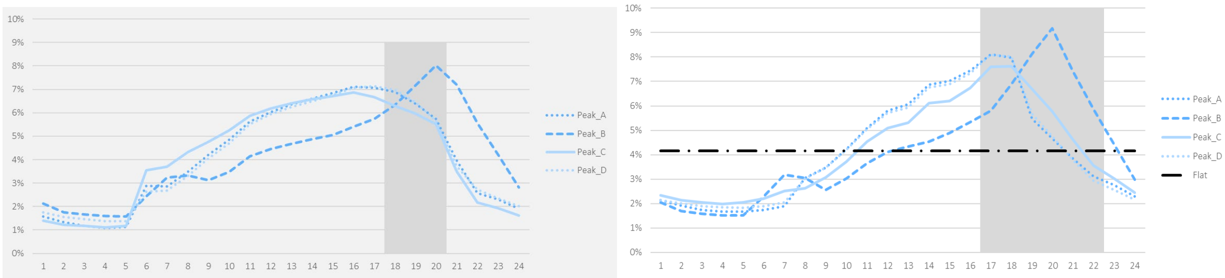

Figure B-6. Before (Left) and After (Right) Peak Window Adjustment for Peak Bundles

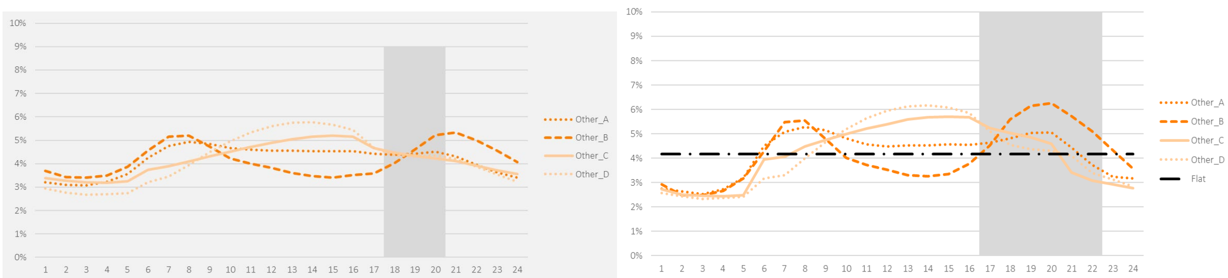

Figure B-7. Before (Left) and After (Right) Peak Window Adjustment for Other Bundles

1.5 Electric Vehicles

The electrification of transportation layer consists of impacts from the charging of light duty electric vehicles (LDEV) and electric buses.

1.5.1 Light Duty Electric Vehicles

The light duty electric vehicle forecast was based on an adoption model developed by Integral Analytics, Inc. as described in Appendix E of the EoT Roadmap[22] to arrive at EV saturations of total light duty vehicles (LDV) by year for each island. Historical data for light duty vehicle registrations were provided by the Department of Business, Economic Development, and Tourism (DBEDT) and reported at the county level. The total light duty vehicle forecast for each county was estimated using a regression model driven by population and jobs based on UHERO's October 2019 economic forecast. The development of the LDEV forecast utilized the EV saturation by island as shown on tab "EV Saturation" in Attachment 8 of PUC-HECO-IR-1 and applied the saturation to the light duty vehicle forecast for each island to arrive at the number of LDEVs.[23] Although EV saturations were not specifically consistent with carbon neutrality in Hawaii by 2045 in the Base LDEV forecast, they are consistent with County goals for 2035.

To estimate the sales impact from EV charging for each island, the annual kWh used per vehicle was calculated based on the following equation:

$$Annual\ kWh\ per\ vehicle\ = \frac{\big(Annual\ VMT * (kWh\ per\ mile)\big) * 10^6}{Total\ LDV\ Forecast}$$

where

- *Annual VMT* is the annual vehicle miles travelled
- *kWh per mile* is a weighted average of fuel economies of electric vehicles registered

Annual VMT is forecasted by applying the baseline economic growth rate developed by the Federal Highway Administration for light duty vehicles to DBEDT's reported vehicle miles travelled for each county.[24] For Lāna'i and Moloka'i, vehicle miles travelled were developed based on information from DBEDT and on-island sources.

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

[23] *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

[24] *See* https://www.fhwa.dot.gov/policyinformation/tables/vmt/vmt_forecast_sum.pdf

Historical *kWh per mile* was obtained using the weighted average fuel economy of registered electric vehicles by island. For Lānaʻi and Molokaʻi, the fuel economy from the Nissan Leaf represented each island's average. Fuel economy and vehicle registration by type data were obtained from the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy and Electric Power Research Institute (EPRI), respectively[25]. *Annual kWh per vehicle* was forecasted by applying a reference growth rate developed using the U.S. Energy Information Administration's (EIA) Annual Energy Outlook to the historical weighted average fuel economies.[26] The reference fuel economy growth rate expected battery technology will improve and more larger vehicles will be produced.

Car registration data at the ownership level was not available to determine whether a car was a personally or commercially owned vehicle. Therefore, a ratio between residential and commercial PV installations in historical years was used to allocate the number of EVs between residential and commercial customers for each island. Within the commercial EVs, a percentage based on PV capacity installed by commercial rate Schedules G, J, and P was applied to the total commercial EV count to calculate the number of EVs at the commercial rate schedule level. The sales impact by rate schedule was calculated by multiplying the number of EVs by sales impact per vehicle for each island.

1.5.1.1 Light Duty Electric Vehicles Charging Profiles

Previous unmanaged charging profiles were developed using third party and public charging station telemetry, load research conducted by several utilities in California, as well as Hawaiian Electric specific advanced metering infrastructure (AMI) data. The unmanaged residential and commercial light duty electric vehicle charging profiles were updated by leveraging data from the Company's DC fast charging network and a case study[27] conducted through the deployment of EnelX's Level 2 chargers in Hawaiʻi. Figure B-8 below highlights the revised residential and commercial charging profiles compared to the previous IGP profiles, including a demand reduction during the evening peak hours in the residential charging profile.

[25] *See* http://www.fueleconomy.gov

[26] *See* https://www.eia.gov/outlooks/aeo/data/browser/#/?id=113-AEO2019&cases=ref2019&sourcekey=0

[27] *See* Smart Charge Hawaiʻi Case Study, In partnership with Hawaiian Electric & Elemental Excelerator, EnelX

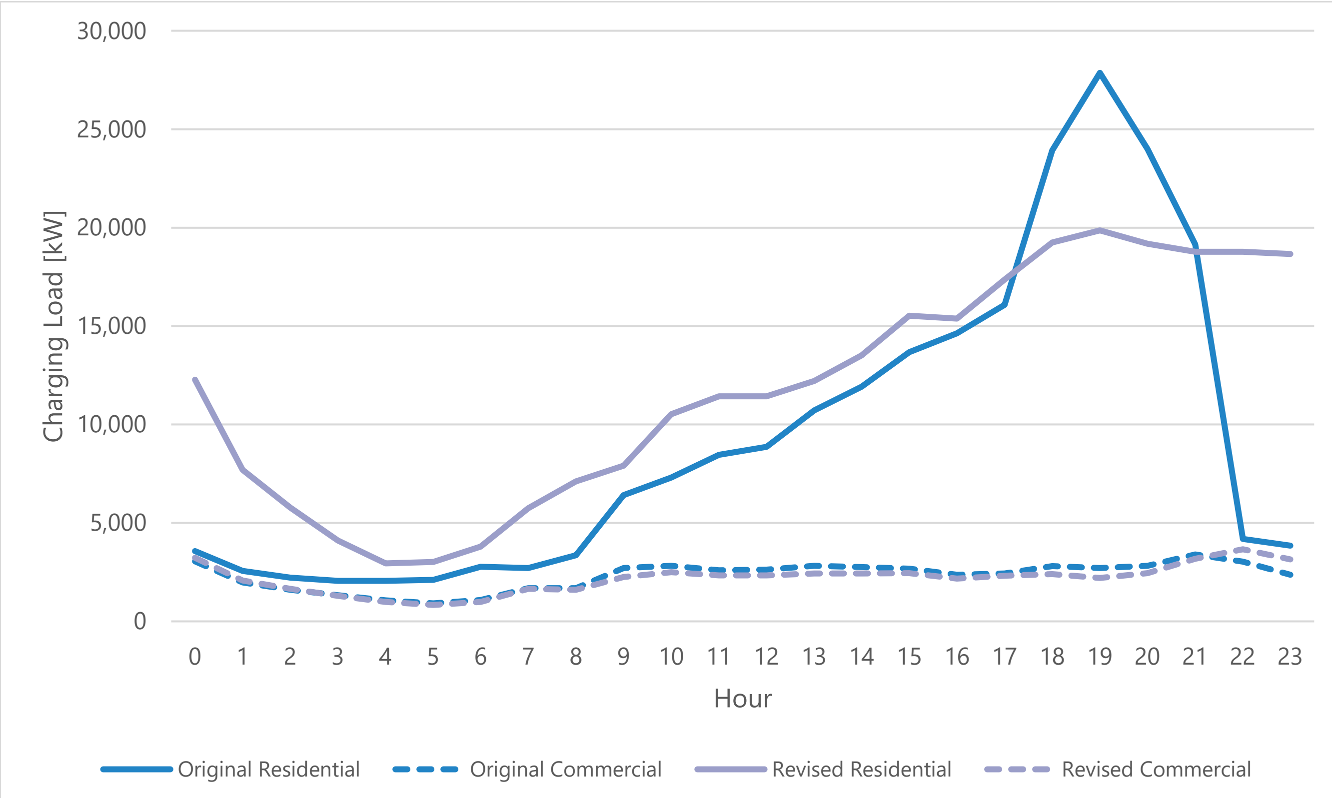

Figure B-8. Light Duty Electric Vehicle Charging Profiles

1.5.2 Electric Buses

The electric bus forecast was based on information provided by the Company's Electrification of Transportation team following 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. Since specific information on the buses were not available for most operators, we used the average bus efficiency (kWh per mile) for two different Proterra models. For each island, the total sales impact for each bus operator was applied to the rate schedule on which each bus operator was serviced.

1.5.3 Electric Vehicle Forecast Sensitivities

Three additional light duty electric vehicle forecast sensitivities (Low, High, and Freeze) were developed using varying adoption saturation curves. A Low Sensitivity forecast was developed using a slower and lower adoption rate forecast from Integral Analytics, Inc's adoption model. The High Sensitivity forecast used the Transcending Oil Report, prepared by the Rhodium Group in 2018, which considered vehicle scrappage rates and the transition rate of vehicle sales to fully electric. The report estimated all vehicle sales by 2030 would need to be electric to reach 100% electric vehicle stock by 2045.[28] A freeze sensitivity was also developed, assuming no new additional electric vehicles above the Base forecast after 2021. Table B-15 summarizes the light duty electric vehicle sensitivities.

Table B-15. 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

[28] 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

1.6 Sales Forecast

Shown below in Figure B-10 through Figure B-14 is the sales forecast for the base scenario and bookend sensitivities for the five islands.

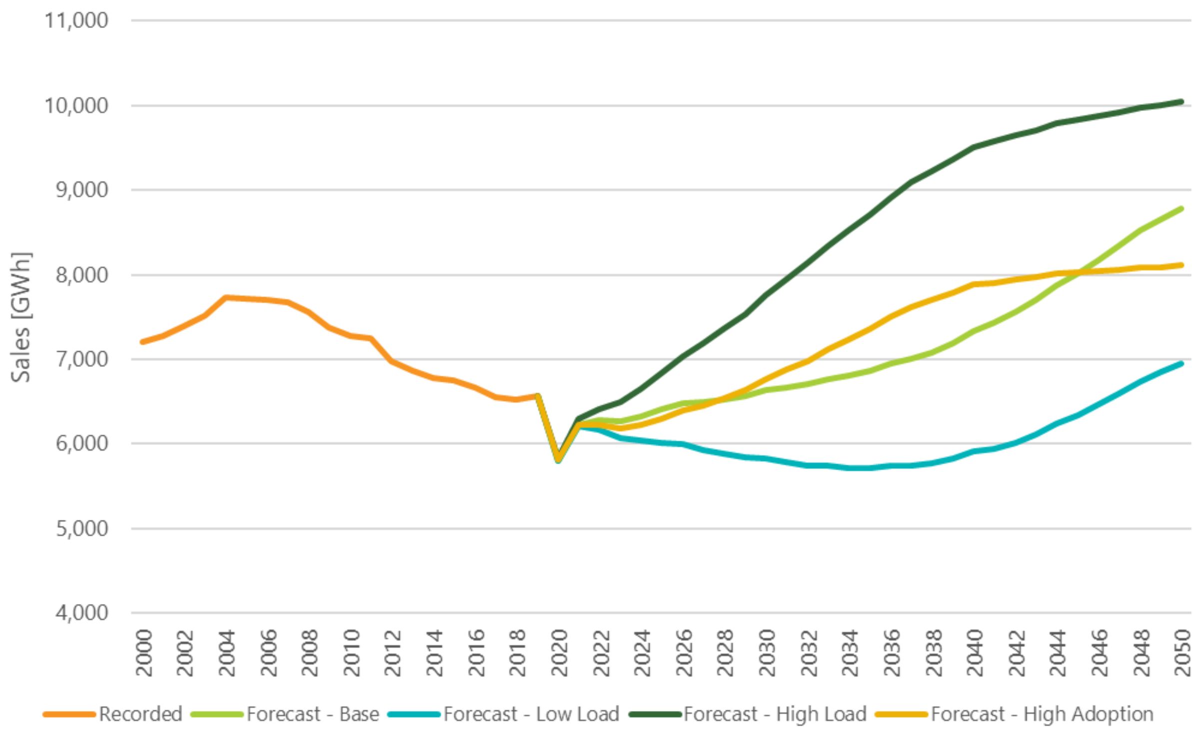

Figure B-9. Oʻahu Sales Forecast Bookend Sensitivities

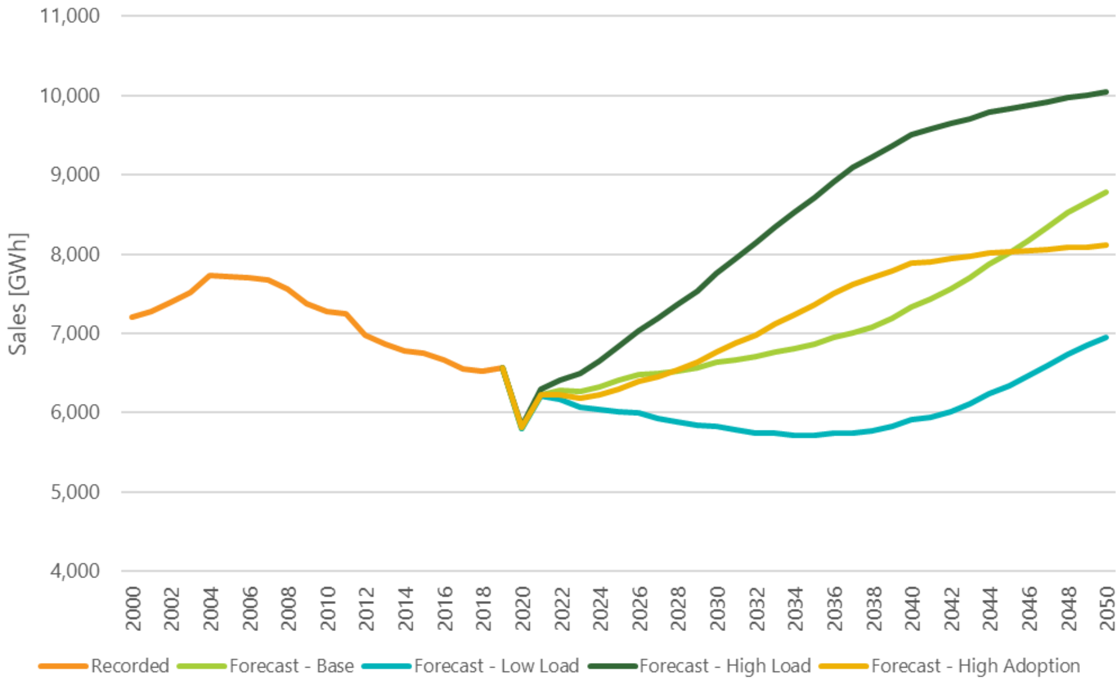

Figure B-10. Hawai'i Island Sales Forecast Bookend Sensitivities

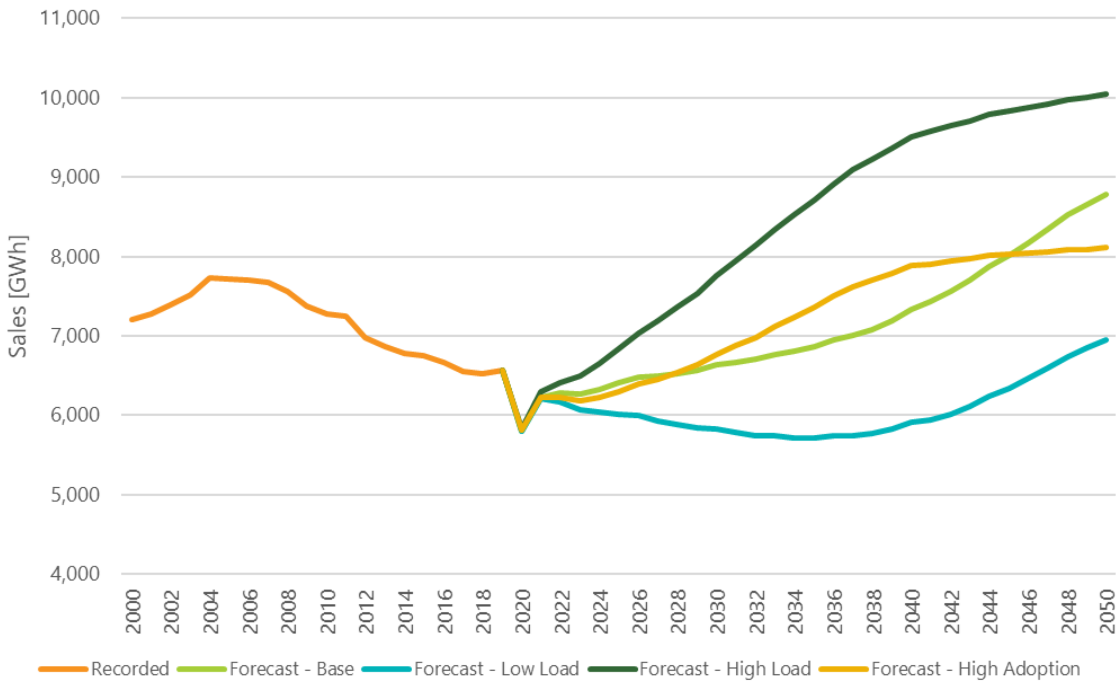

Figure B-11. Maui Sales Forecast Bookend Sensitivities

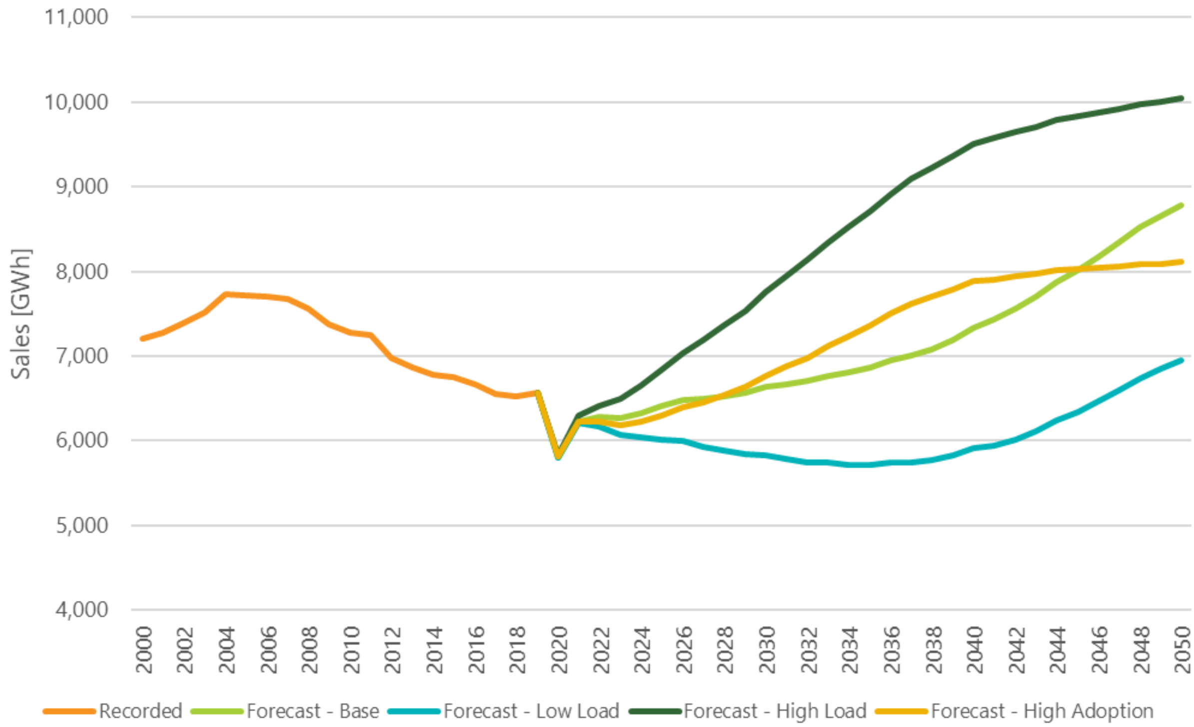

Figure B-12. Moloka'i Sales Forecast Bookend Sensitivities

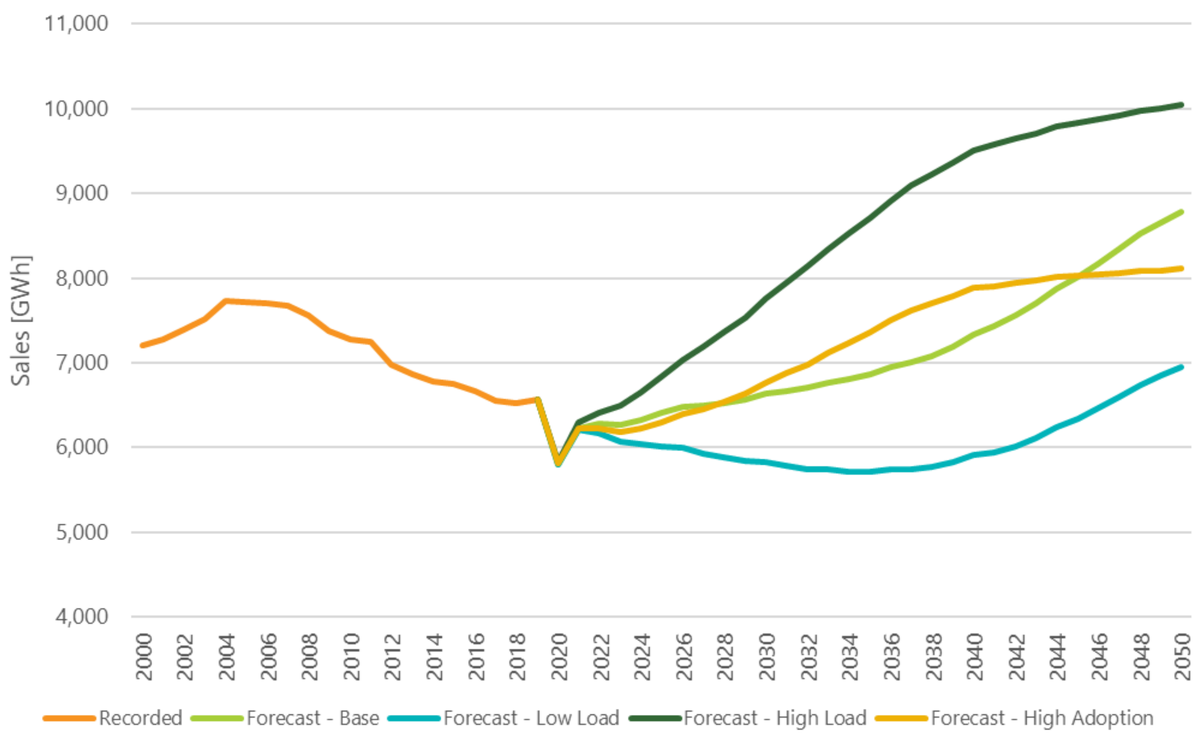

Figure B-13. Lāna'i Sales Forecast Bookend Sensitivities

1.7 Peak Forecast

Shown below in Figure B-15 through Figure B-19 is the peak forecast for the base scenario and bookend sensitivities for the five islands.

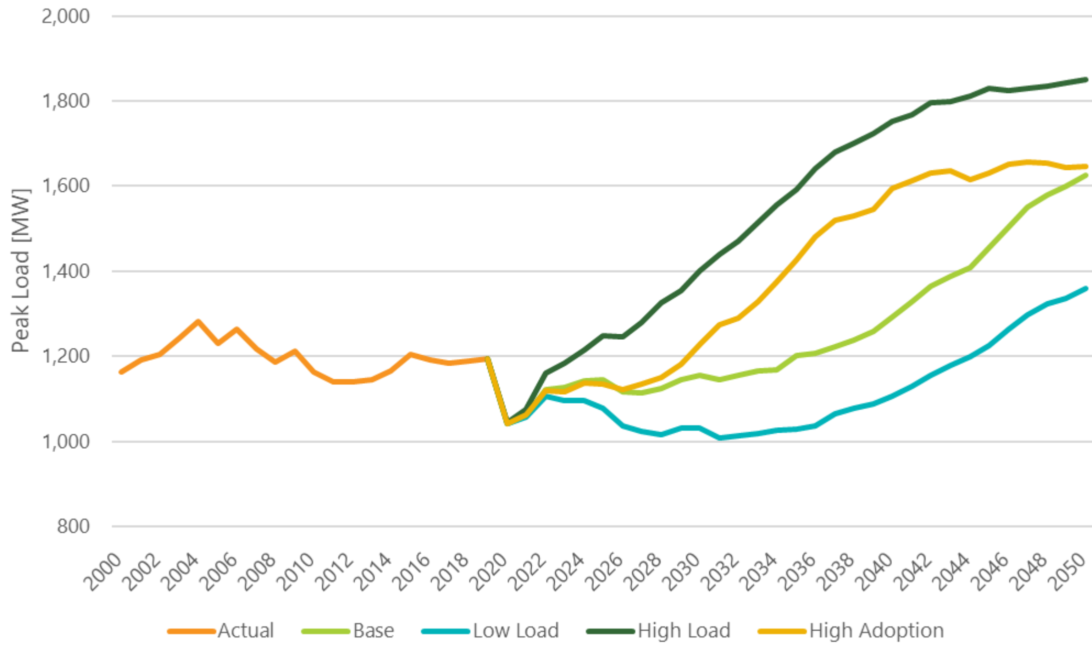

Figure B-14. O'ahu Peak Forecast Bookend Sensitivities

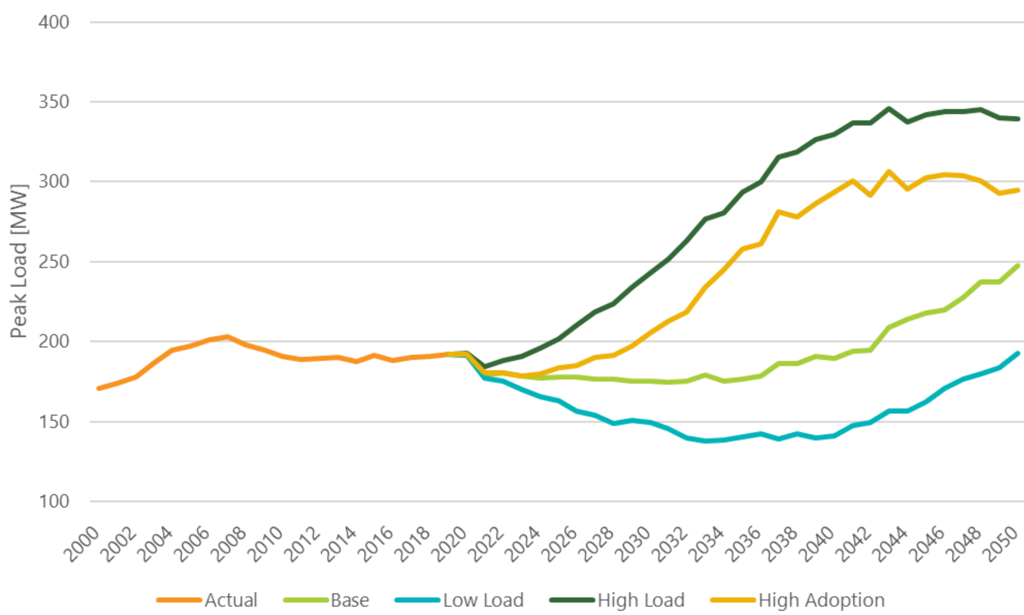

Figure B-15. Hawai'i Island Peak Forecast Bookend Sensitivities

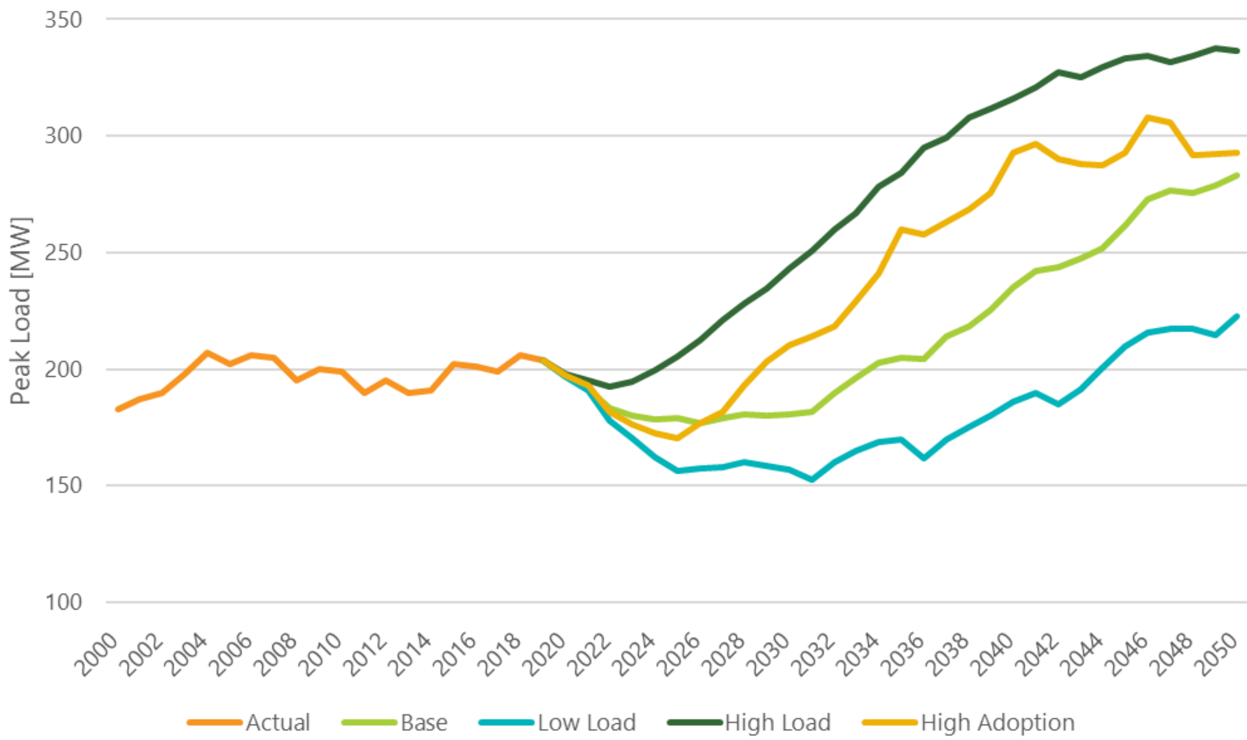

Figure B-16. Maui Peak Forecast Bookend Sensitivities

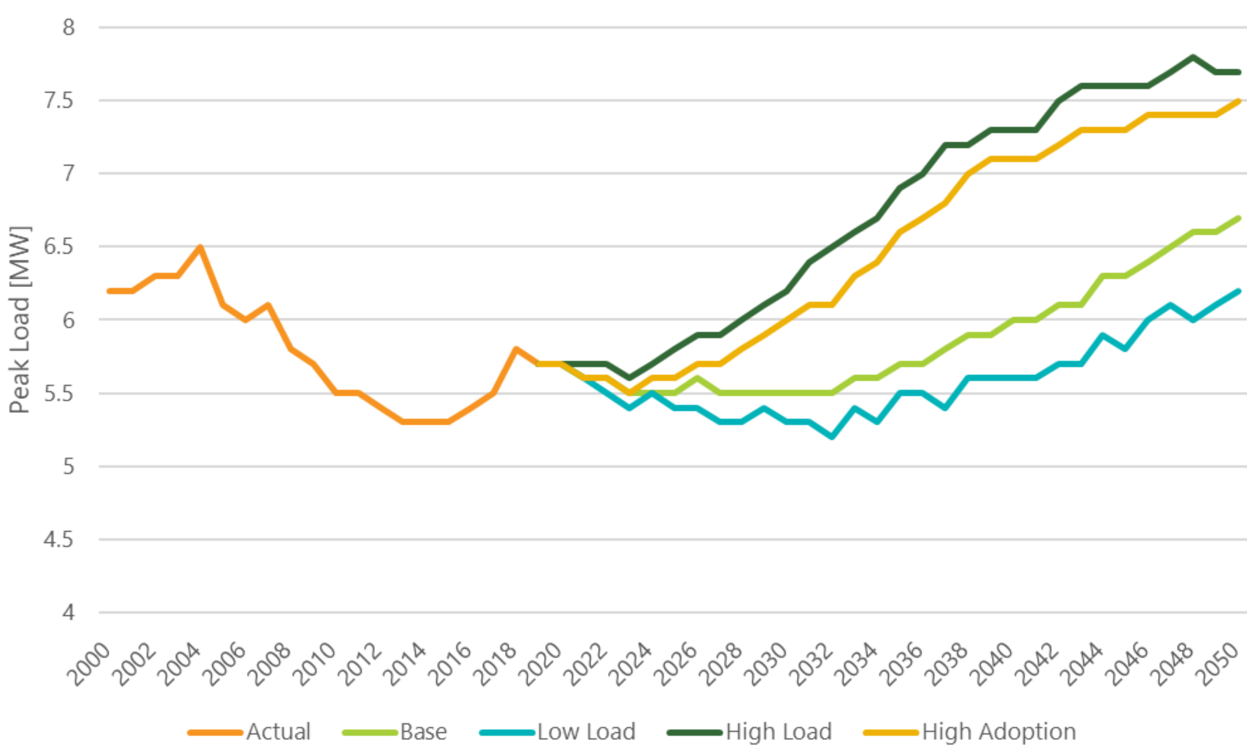

Figure B-17. Moloka'i Peak Forecast Bookend Sensitivities

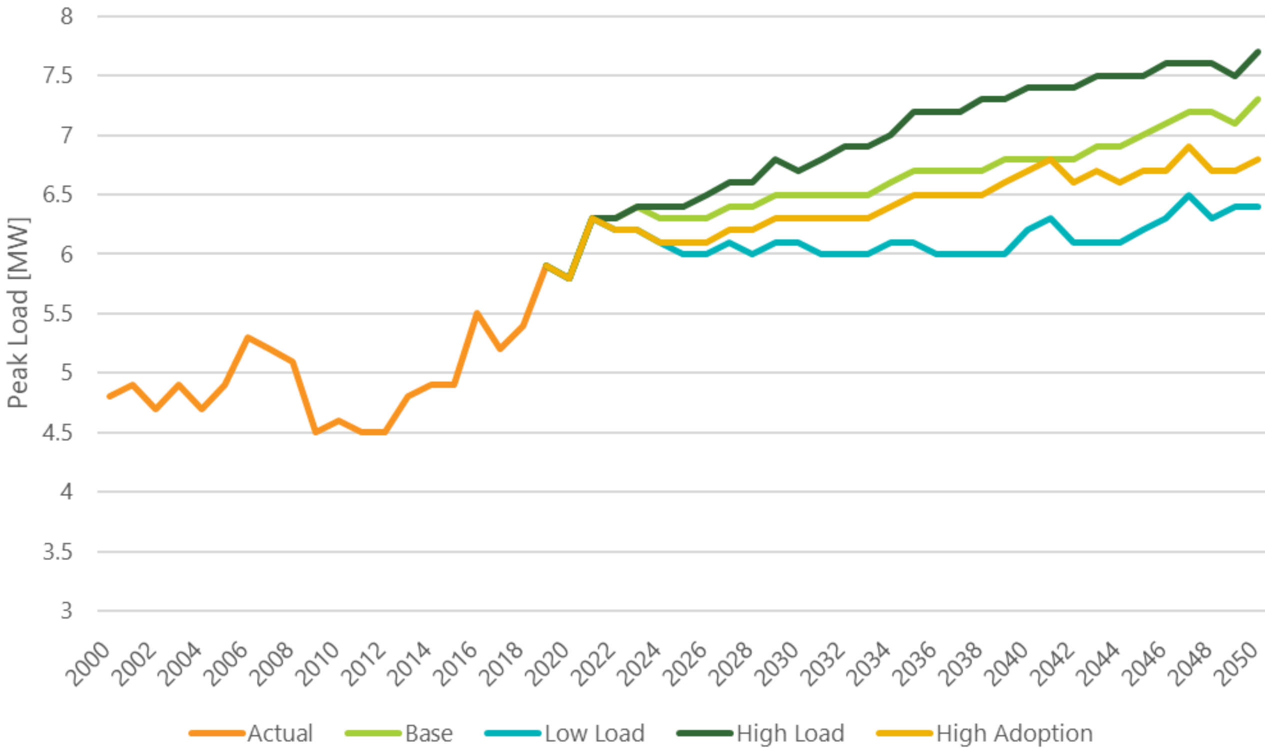

Figure B-18. Lāna'i Peak Forecast Bookend Sensitivities

2. IGP Modeling Methodology

This section describes the analytical methodology used to identify the needs of the future grid to meet various policy objectives. We used a suite of modeling tools to assess the grid needs, which set out to:

1. Identify the near-term quantity and timing of Grid Needs that will drive future program development and procurement in each IGP cycle over the next decade;
2. Develop resource plans to identify potential pathways to solve for near-term needs and long-term objectives such as achieving 100% renewable energy and net zero carbon emissions by 2045; and
3. Evaluate proposed solutions through the creation of an energy marketplace in Hawaii.

We worked extensively with the Solution Evaluation Optimization Working Group ("SEOWG"), the Stakeholder Technical Working Group ("STWG"), the Technical Advisory Panel ("TAP"), and the Stakeholder Council to develop the methodologies. The following sections describe the overall process flow and modeling framework to derive the Grid Needs to inform solution sourcing and to evaluate or select solutions.

2.1 Modeling Objectives

We considered six overarching objectives to deliver reliable, clean, and cost-effective service to customers.

- Renewable Portfolio Standards
- System Reliability
- Affordability
- Environmental Carbon Impact Reduction
- Grid Resilience
- Community Impacts and Land Use

2.1.1 Renewable Portfolio Standards (RPS)

The Grid Needs Assessment will seek to achieve and accelerate the State of Hawaiʻi's Renewable Portfolio Standards ("RPS") mandate of achieving 100% renewable energy by year 2045, with breakout targets shown in Figure B-20.

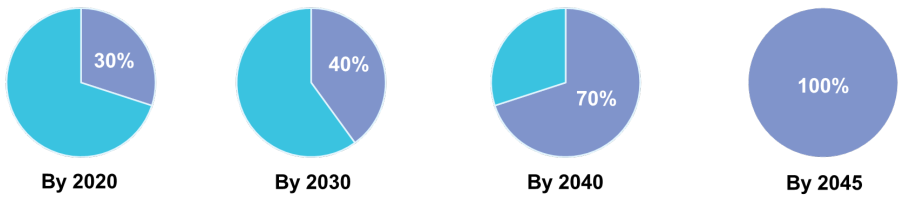

Figure B-19. State of Hawai'i Renewable Portfolio Standard (RPS) Targets by Year

Under performance based regulation, we are incentivized to accelerate renewable energy achievement through annual renewable energy targets. As recommended by the Stakeholder Council, the Grid Needs Assessment should seek a portfolio that recognizes the RPS-A performance incentive mechanism. RPS achievement simultaneously meets our carbon reduction goals.

2.1.2 System Reliability

The Grid Needs Assessment will account for multiple factors that assure system reliability; for example, system balancing, system security, and T&D reliability. Additionally, we are accountable for Adequacy of Supply, which is the ability of the electric system to supply the aggregate electrical demand and energy requirements of our customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements. Aspects of reliability will be evaluated through the Grid Needs Assessment for adherence to various reliability related planning criteria and guidelines.

2.1.3 Affordability

The capacity expansion modeling tool will develop a resource portfolio to solve for RPS and system reliability objectives in a least-cost manner. In the development of the resource plans, the model will also consider the costs of installing new resources as well as the costs of operating existing resources. The resource plan will provide insight into resource procurement and system investment decisions needed to achieve 100% renewable energy over the next 25 years.

2.1.4 Environmental Carbon Impact Reduction

With increasing renewable generation on the grid and the retirement of fossil fuel generating units, the expectation is that greenhouse gas ("GHG") emissions will significantly decline. Long-term plans can be qualitatively and quantitatively assessed for GHG reduction. Quantitative GHG reduction assessments of resource plans may also incorporate achievement of certain GHG reduction targets or estimated reductions from an energy ecosystem perspective to include estimated reductions gained through electrification of other sectors, including transportation, buildings, etc.

2.1.5 Grid Resilience

There are two primary ways of looking at grid resilience. The first involves hardening of existing grid infrastructure (*e.g.,* upgrades to utility poles, transmission and distribution line monitoring, transformers, etc.) and the second includes the ability of the system to return to service in a major outage event (*e.g.,* hurricane, tsunami, flooding, etc.). As outlined in the *Resilience Working Group Report for Integrated Grid Planning,*[29] comments from first responders, other infrastructure owners, and other RWG participants will be used to inform transmission and distribution planning needs, priorities for resilience improvements, and options to achieve those identified planning needs and priorities. Notably, this includes consideration of resilience enhancing microgrids to provide local, emergency power generation when parts of the system's transmission and/or distribution system are out of service due to emergency conditions.

2.1.6 Community Impacts and Land Use

The viability of a long-term plan will depend on an assessment of community impacts and land use in Hawaii. It is imperative that any long-term plans balance multiple state policy objectives, such as housing, energy, and food sustainability.

Stakeholder Council used feedback on community impacts and land use to inform a key model input. As an example, the resource potential for land-based resources that define the maximum capacity of each resource that can be developed on each island. As part of the modeling input development, we engaged NREL to perform a solar and wind resource potential study. The stakeholder council provided specific parameters such as land slope and exclusions of certain type of land that could be developed for grid-scale solar.

2.2 Overview & Purpose of Modeling Tools

We use several modeling tools to identify the grid needs across our generation, transmission, and distribution systems, and worked with the Hawaii Natural Energy Institute ("HNEI") and the Technical Advisory Panel to establish a modeling framework, as shown in Figure B-21, for the Grid Needs Assessment methodology that will be used throughout the various phases of the IGP process.

[29] *See* https://www.hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning/stakeholder-engagement/working-groups/resilience-documents

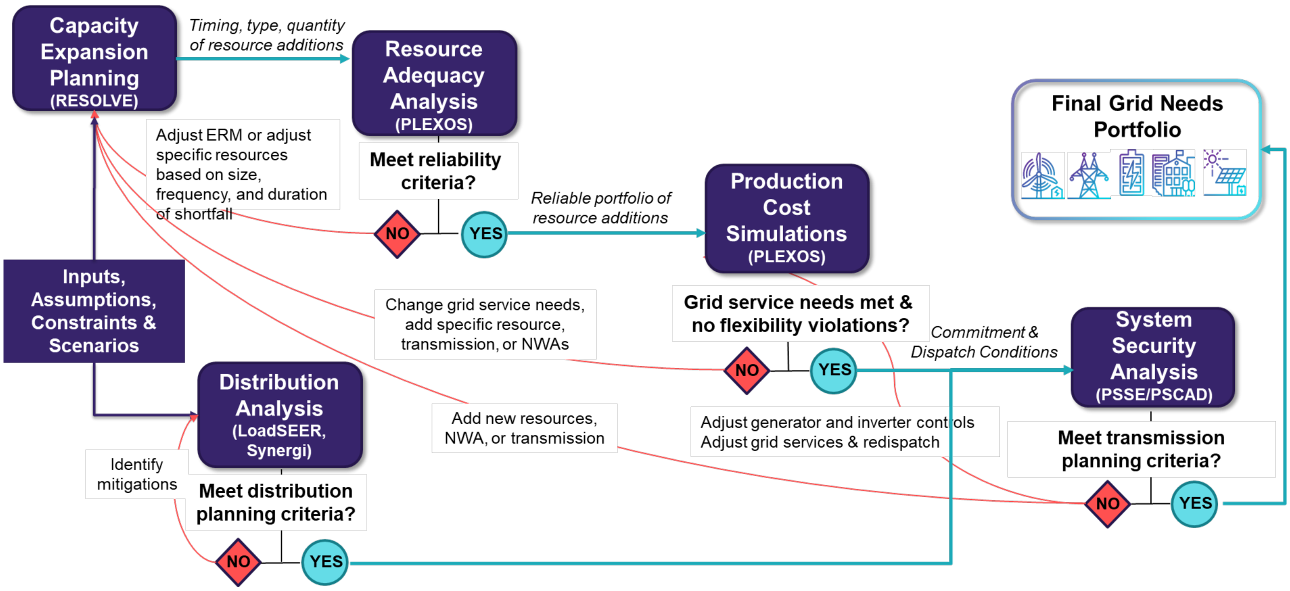

Figure B-20. Grid Needs Assessment Modeling Framework (Adapted from HNEI)

Two computer models that layout the pathways to identify the Grid Needs are the RESOLVE model and the PLEXOS model. RESOLVE produces an optimized resource plan of proxy resources that can fulfill the Grid Needs. The primary objective of this phase of the process is to identify Grid Needs using proxy resources; the actual technologies and solutions are determined during the solution sourcing which could consist of projects, procurements, or programs. In other words, the Grid Needs Assessment is not intended to select or express a preference for a technology; rather identify what is needed for the system and allow the market to propose solutions to meet those needs. In addition to the RESOLVE base case that is developed using a base set of planning assumptions, further sensitivities are run in RESOLVE to better understand how certain assumptions influence outcomes that informs a robust action plan.

The resource adequacy of a resource plan is then evaluated in PLEXOS.The operations and cost to operate the system are simulated through an hourly production simulation to ensure that the Grid Needs continue to be met on an 8760 hourly basis through year 2050. The results of the production simulation in PLEXOS are then used as inputs into the System Security analysis. The System Security analysis will be completed in PSS/E, PSCAD, and/or ASPEN Oneliner to evaluate needs for short circuit current, inertia, frequency response, voltage support, and assess inverter control interactions, weak grid/system strength issues. If the System Security step (or any of the other steps) identifies any shortfalls in the Grid Needs, the resource plan may be iterated upon to meet those residual needs. To address shortfalls in the Grid Needs, the proxy resources identified in the resource plan may be increased or accelerated from future years. It should be noted that the Capacity Expansion model and Resource Adequacy step is initially run unconstrained, which means there are no system security or operational rules assumed. With this approach, iteration of these steps are likely needed given the dynamic environment of a high-inverter based resource portfolio.

2.2.1 Modeling Framework

Each step in the modeling framework has a different objective. The TAP advised that the full suite of modeling tools should be utilized in assessing the Grid Needs. For example, in its independent review, the TAP stated:[30]

> RESOLVE provides limited fidelity and should be used only as a technology screening tool. Subsequent determination of reliability, analysis of multi-year weather data, retirements, and avoided costs, etc. requires the use of other modeling tools. It was emphasized more than once that the other models should be an integral part of the overall process, NOT just a check on the output from RESOLVE.

Figure B-22 describes an overview of the objectives, key inputs, and outputs of each modeling step and tool. Each modeling software tool is described in the following sections, including a discussion of when adjustments or iterations may be made in each step. These decisions cannot be quantified solely by a set of criteria. Engineering judgment is needed when making decisions to adjust or iterate a modeling step. Adjustments or iterations could include a decision on whether a shortfall in capacity to meet reliability criteria is needed. On this issue, we posed the following questions to the TAP: What is the level of tolerance to decide when to go back and iterate and is it necessary to always rerun the full process or can estimations serve to backfill shortfalls? The TAP's response is summarized below.

> TAP did not provide a hard and fast answer to these questions, noting the need for 'engineering judgment' and 'experience' to determine what needs to be done. While TAP recognizes that engineering judgment can reduce the requirement for the full process to be used for all iterations, TAP recommends that solutions be vetted by the full process before proceeding to the procurement phase.[31]

[30] *See* Grid Services and Planning Criteria Feedback filed in Docket No. 2018-1065 on June 1, 2021 at 4.

[31] *Id.* at 4.

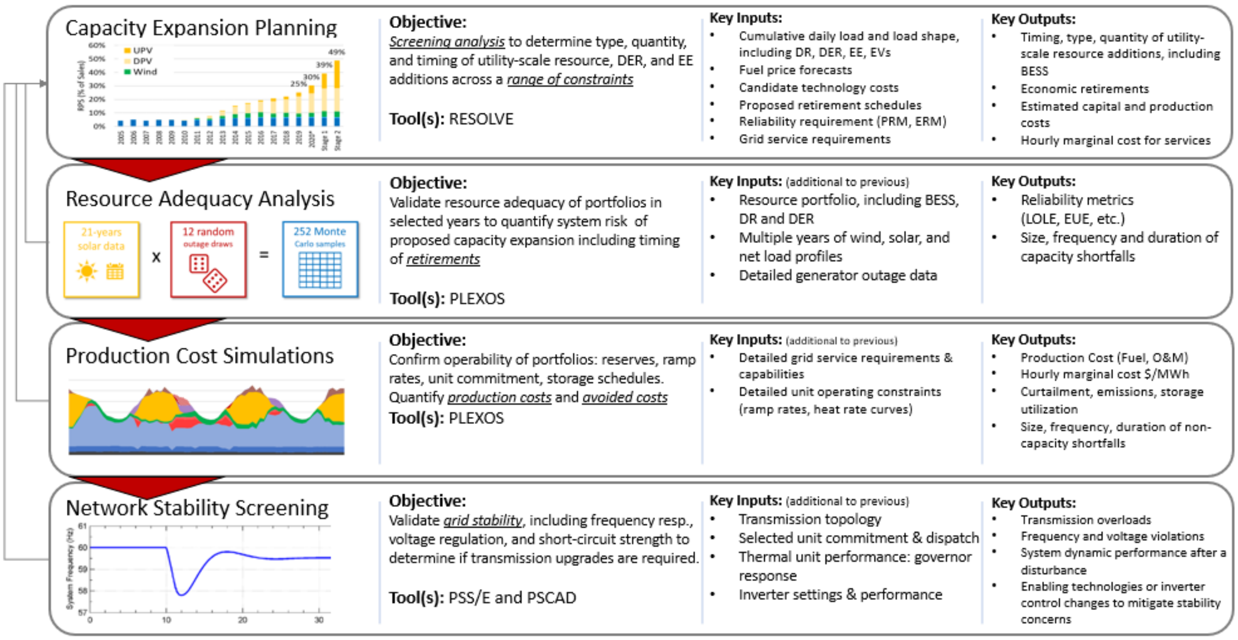

Figure B-21. Key Inputs and Outputs of Modeling Steps

2.2.2 Capacity Expansion (RESOLVE) overview

The grid needs assessment uses the planning assumptions from the approved March 2022 Inputs and Assumptions. The primary objective of this phase of the process was to identify the optimal mix of proxy resources that are built to represent the system's grid needs. RESOLVE is intended to provide directional guidance as to the optimal mix of resources; it is not intended to be a prescriptive pathway that must be strictly followed during solution sourcing activities.

2.2.3 Resource Adequacy (PLEXOS) overview

The Resource Adequacy step includes a probabilistic analysis consistent with industry best practices, including recommendations we adopted from the TAP. The resource adequacy analysis is probabilistic and evaluates the reliability of the system using 5 weather years based on meteorological data and 50 randomized generator outages for a total of 250 iterations. Specifically, PV reliability was based on five years of NREL data, from 2015 through 2019, which was provided as part of the NREL Resource Potential study. Wind reliability was based on historical measured data from existing wind plants for the same five years. DER used historical monthly capacity factor measurements also from the same five years. Thermal generators had 50 random outage samples with each sample modeled as an independent production simulation. A total of 250 (50 outage samples per year for five weather years) samples were modeled.

The results are then used to calculate various reliability metrics including loss of load expectation (LOLE), loss of load events (LOLEv), loss of load hours (LOLH) and expected unserved energy (EUE) to assess reliability. If a portfolio is found to be short of capacity, specifically in the near-term, adjustments to the resource portfolio may be made during this step.

Loss of Load Expectation (LOLE) is the number of days per year where there is unserved energy. The unserved energy within the day is quantified as Loss of Load Events (LOLEv) defined as the number of unserved energy events per year. The difference between LOLE and LOLEv is that multiple unserved energy events can occur in a single day. Loss of Load Hours (LOLH) is the number of hours of unserved energy. One unserved energy event can last for one or more hours, and therefore, an LOLE of 0.1 days/year is not necessarily the same result as an LOLH of 2.4 hours/year. Expected Unserved Energy (EUE) is the amount of unserved energy. Examples of the various metrics and their interrelationship were shared in the Stakeholder Technical Working Group meeting on June 9, 2022 and recapped below in Figure B-23. As shown, while the day has unserved energy, the magnitude, duration, and frequency of that unserved energy affects the various metrics.

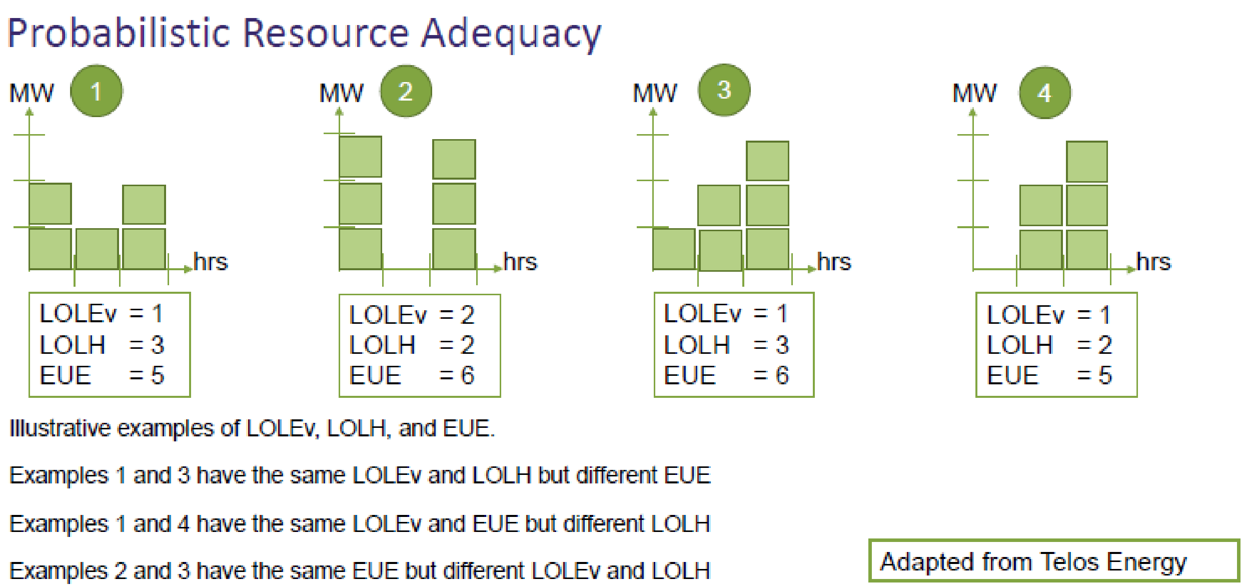

Figure B-22. Probabilistic resource adequacy metrics examples

2.2.4 Production Cost and Operational Flexibility (PLEXOS) overview

The PLEXOS modeling software is used to perform production cost simulations. The objective of the production cost simulation is to confirm operability of the portfolios by modeling the operation of the electric system, accounting for regulating reserves, ramp rates, unit commitment, and storage charging and discharging through economic dispatch. This provides insight into how the new resources will be operated and dispatched in future years. More accurate costs of long-term plans will be developed as part of the solution sourcing process when actual market solutions are proposed with current market pricing. Total production costs and avoided costs are quantitative outputs of the production cost simulations.

2.2.5 System Security (PSSS/E and PSCAD) overview

Transmission Needs will be analyzed by the applicable system models. Identified needs, as described in this section, include the following transmission grid services:

- Inertia
- Voltage support
- Fast frequency response (FFR)
- Primary frequency response (PFR)
- Short-circuit current
- Transmission Capacity

There are two major components to inform transmission needs – system security analysis and steady-state analysis which builds upon the Renewable Energy Zone (REZ) study. These analyses are guided by the transmission planning criteria for each island. The TAP conducted a review of the transmission planning criteria and the system security process. The incorporation of their recommendations and feedback is included in the *September 2022 GNA Methodology Report*.

Steady-state analysis is performed in PSS/E, which analyzes system steady state voltages and transmission line loading. For each island, transmission networks, including trasmission lines, generation, substation transformers and loads, are modeled in PSS/E. Selected system generation dispatches with system load scenarios are represented in PSS/E, by modifying generation parameters (i.e., MW and MVar). The distribution system (distribution circuits, customer loads, and DER) is not modeled in detail in this steady state analysis, but represented as aggregated load and generation in each distribution bus of distribution substation transformers (for Hawaiʻi island system and Maui system) and each substransmission bus of transmission substation transformers (for Oʻahu system). Modeling of the full transmission network allows us to identify any equipment overloads or voltage violations per the transmission planning criteria.

The other component of system security study evaluates system dynamic stability conditions and determines related grid needs. Traditionally, the dynamic stabilty can be studied in the PSS/E as well. However, PSS/E dynamic stability simulation capability is more suitable for traditional synchronous machine dominated power systems in which electric-mechanical dynamics are the core component of system dynamic stability. Because our power system today and in the future is increasingly dominated by inverter-based systems (for solar, wind and battery energy storage), instead of synchronous machine based generation, a different type of software, PSCAD/EMTDC, is used to perform system dynamic stabilty. The PSCAD/EMTDC is one of few commercial avaiable utility grade software specifically designed for performing electromagnectic transient (“EMT”) simulation. This is the most popular EMT software currently among utilities, equipment manufactureres and research institutes in North America. A PSCAD simulation normally represents one system planning event (e.g., a generator trip) in one pre-defined system dispatch (e.g., daytime peak load high DER generation dispatch). We normally simulate 30 seconds of real time of an event like a storm causing a transmission line to unexpectedly trip offline. 10-14 hours are some times needed to complete these highly complex simulations.

The analysis will produce the following key deliverables:

- Strategies and mitigations required for safe and reliable operation of the grid based on resource portfolio(s)
- Typical and/or boundary dispatch and operational requirements for grid operation based on resource portfolio(s)
- Frequency stability, voltage stability, control stability and rotor angle stability (if applicable) performance of the future grid
- Evaluation of the need for grid forming technology and demonstration of system performance with this technology when and if needed for the future grid
- Evaluation of weak grid issues and development of a "weak grid" definition for each of the island grids, which includes investments or mitigation strategies to operate a grid with limited to no synchronous generation. Weak grid conditions could include low short circuit current availability, low inertia, and limited reactive power support.
- Identification of additional transmission grid services needed over the near-term 5-year planning horizon

2.2.5.1 Renewable energy zones

The second component in assessing transmission needs is the development of renewable energy zones (REZ), which includes development of transmission capacity needs to integrate higher levels of renewable energy. The transmission needs assessment leverages the *July 2021 Assessment of Wind and Photovoltaic Technical Potential Report* to identify long term transmission capacity needs to harness renewable energy potential on each island.

The REZ concept[32] will require an extensive planning process centered around community and stakeholder engagement; however, the intent of the renewable energy zone analysis is to identify the cost of potential transmission upgrades that will allow RESOLVE to determine whether generation in various areas on each island and transmission buildout decisions are least-cost compared to other alternatives or alternate sites and resources. If determined to be directionally cost-effective then developing renewable energy zones may be pursued further.

[32] *See* NREL's renewable energy zone guidebook, https://www.nrel.gov/docs/fy17osti/69043.pdf and the process undertaken at AEMO, https://aemo.com.au/-/media/files/major-publications/isp/2020/appendix--5.pdf?la=en

2.2.6 Synergi and LoadSEER overview

The distribution system analysis step will primarily use two different modeling tools: (1) LoadSEER, an agent-based forecasting engine, and (2) Synergi software, a steady-state distribution power flow modeling tool.

LoadSEER creates local, distribution level forecast by distribution substation and circuit. This electric load forecasting software incorporates our corporate load forecasts and a multitude of other inputs to create forecasts at the circuit and substation transformer level.

The objective of LoadSEER is to statistically represent the geographic, economic, and weather diversity across our service territory, and to use that information to forecast how circuit- and transformer-level hourly load profiles will change over the next 30 years. Because of the complexity of the forecasting challenge, LoadSEER employs multiple statistical methods, including hourly load modeling, macro-economic modeling, customer-level economic modeling, and geospatial agent-based modeling, which taken together increase the validity and reduce uncertainty associated with the forecasts.

The bottom-up parcel level methodology used by LoadSEER aligns with corporate-level forecasts, such that stakeholders are assured that these scenarios are grounded in a shared vision of the service territory, in aggregate.

Hourly customer class and feeder load shapes, distribution energy resource ("DER") shapes, and DER forecasts are jointly overlaid within the base load, agent model growth, and known new load service requests to derive the overall forecast load profile for each circuit, such that all resource and load factors contributing to the circuit's load at risk can be accurately assessed.

These bottom-up simulations provide circuit-by-circuit forecast. The circuit level data is then readily aggregated up to the transformer and substation levels, and input from local knowledge to fine tune the model. This helps improve the scenario forecast's quality and usability.

The Synergi modeling tool is a steady-state power flow software that is able to model each distribution substation and circuit. The tool is used to assess circuit-level loading and hosting capacity utilizing the circuit-level forecasts generated by LoadSEER. Synergi then determines if a distribution planning capacity or voltage criterion is violated. Then mitigations can be identified to allow integration of the forecasted amount of load and DER. Although the secondary wires are not included in the model, behind the meter customer assets such as rooftop solar and battery energy storage are modeled and aggregated at the distribution service transformer.

2.2.6.1 Distribution Planning Process and Methodology

As the power supply and electrical distribution systems transition to an integrated system, the planning processes must also transition. Hence today's distribution planning methodology must ensure the orderly expansion of the distribution system and fulfill the following core functions:

- Plan the distribution system's capability to serve new and future electrical load growth, including electric vehicle (EV) growth
- Safely interconnect DER, such as photovoltaic (PV) systems and energy storage systems that transmit power across the system in a two-way flow, while maintaining power quality and reliability for all customers
- Incorporate the locational benefits of DER in the evaluation of grid needs and system upgrades

We engaged with customers and stakeholders to seek input and feedback on the distribution planning methodology as part of the Distribution Planning Working Group. This has afforded opportunities for stakeholders to collaborate and co-develop the distribution planning methodology for identifying grid needs, as described in the *September 2022 GNA Methodology Report.*

The distribution grid needs will be the foundation that drives solution options, including non-wires alternative (NWA) opportunities.

Overview

The distribution planning process occurs annually and includes four stages: Forecast, Analysis, Solution Options, and Evaluation (see Figure B-24).

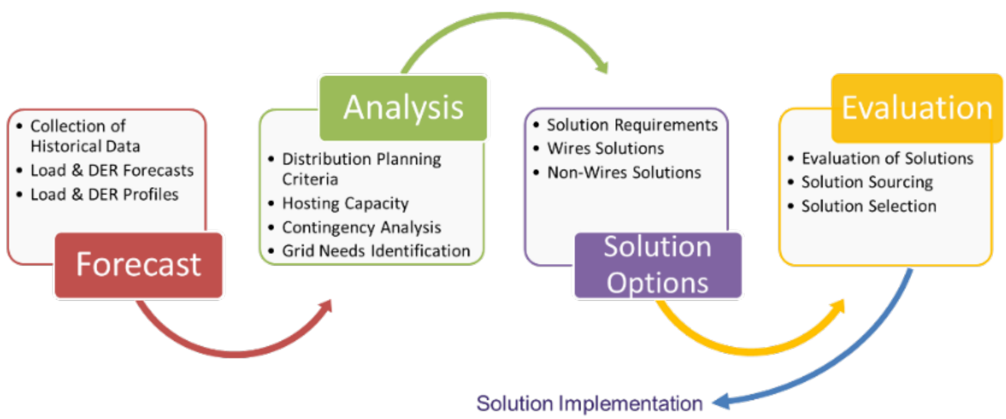

Figure B-23. Stages of the Distribution Planning Process

Stages

The forecast stage begins at the start of the calendar year when the prior year's circuit and transformer load data and the corporate demand and DER forecasts are available for input in the LoadSEER tool to create circuit- and transformer-level load forecasts.

The analysis stage involves the analysis of the electrical distribution system to ensure that there is adequate capacity and reliability (back-tie capabilities) to accommodate the load and DER forecasts. Planning criteria have been established that provide the basis for determining the adequacy of the electric distribution system. In situations where the criteria are not met, grid needs are identified.

In the solution options stage, requirements to meet the grid needs are determined, and wires and non-wires options are developed. The *Non-Wires Opportunity Evaluation Methodology* report attached in Appendix F describes the process to identify favorable NWA opportunities.

These options are evaluated in the fourth stage of the distribution planning process, with the most cost-effective, feasible solution selected that meets the grid need requirements and needby date.

It is worth noting that during the calendar year, it is expected that new service requests, DER, or projects will arise that will require modifications to the circuit- and or transformer-level forecasts. We continually evaluate grid needs throughout the year and make decisions on when to address any grid deficiencies identified outside of the forecast and analysis stages.

3. Reliability Criteria

3.1 Resource Adequacy Criteria

Within the IGP process the energy reserve margin or ERM along with the hourly dependable capacity or HDC is used as an input to the RESOLVE capacity expansion modeling to ensure that the optimization ensures a reliable system. The ERM and HDC methodology is described in the September 2022 GNA Methodology Report.

The ERM is the percentage of system load by which the system capacity must exceed the system load in each hour. The energy reserve margin for each island is listed in Table B-16 below.

Table B-16. Energy Reserve Margin Percentages by Island

Island	Energy Reserve Margin
Oʻahu	30%
Hawaiʻi	30%
Maui	30%
Molokaʻi	60%
Lānaʻi	60%

Energy reserve margins are derived from an assessment of historical data. Identified 'at risk' hours were evaluated to determine minimum energy reserve targets for planning purposes. The loss of largest unit, multiple forced outages, and unplanned maintenance were some of the largest contributing factors for hours considered to be at-risk. Energy reserve margin targets plan for the loss of largest unit and an additional hourly reserve for emergencies. However, it does not directly assign specific reserves to cover different events discretely. The ERM is intended to mitigate a variety of risks including the loss of the largest unit. As an example of the dynamics, the loss of a 180 MW (largest) unit for a peak load of 1,200 MW represents 15%; the loss of the same unit during a shoulder peak load of 600 MW represents 30%. Therefore, the ERM does not explicitly allocate a percentage to the loss of the largest unit and the other portion to other specific type of events that may occur.

The size of generating units on each island are contributing factors to energy reserve margin targets. For instance, on Molokaʻi and Lānaʻi, the largest generating units on the island have the capability to produce roughly 60% of each island's average daily energy usage. For comparison to the current planning criteria described above, which is to meet the peak load with the loss of the largest available unit, the 60% energy reserve margin target for Molokaʻi and Lānaʻi is to plan for resources that can generate enough energy throughout the day to meet the island's energy load without the largest available unit.

The Hourly Dependable Capacity ("HDC") for variable renewable resources is calculated as the typical day in the month and is the minimum expected capacity from variable generation resources based on empirical data. Based on feedback from the TAP, the HDC (MW) is calculated as an 80 percent probability of exceedance by hour, i.e. for each hour of the month, 80 percent of the analyzed distribution of variable renewable resource generation was at or above its stated HDC.

To assess the adequacy of a resource plan, probabilistic reliability metrics are used in the resource adequacy step. Four metrics are reported and used to compare the various cases -- loss of load expectation (LOLE), loss of load events (LOLEv), loss of load hours (LOLH) and expected unserved energy (EUE). Consistent with the typical North America guideline for LOLE, we use 0.1 days per year LOLE in our assessment of various resource portfolios. The lower the LOLE (i.e., (≤0.1) the more reliable a resource plan will be in its ability to serve the electric demand. This provides a useful frame of reference when evaluating resource plans that consider different additions of variable renewables and thermal resources. Stricter reliability thresholds may be warranted to address generation resilience on isolated island grids as high impact, low frequency events increase in frequency.

3.2 Operating Reserves (Reg Reserve)

The regulating reserve requirements were based on the methodology described in the S*eptember 2022 GNA Methodology Report* . This analysis included both the 1-minute and 30-minute regulating reserve requirements. The purpose of the regulation criteria is to establish guidelines to minimize the risk of supply and demand imbalances by ensuring sufficient regulating reserves are available to the system in long-range planning studies. This criterion applies to private rooftop solar systems, standalone grid-scale solar resources, standalone grid-scale wind resources, and gross system load.

3.3 Transmission Criteria

The transmission planning criteria for the O'ahu, Maui and Hawai'i island transmission system establish guidelines to ensure safe and reliable service to its customers for current and future system needs. These criteria also apply to facilities that interconnect to the transmission system. The primary objectives of these criteria to maintain reliable Transmission System operation (i.e., continuity of service) include the following:

- Ensure public safety.
- Maintain system stability under a wide range of operating onditions.
- Maintain equipment operating limits under a wide range of operating conditions.
- Minimize losses where cost effective.
- Pereserve the reliability of the existing transmission infrastructure.
- Maintain an acceptable level of impact to customers for contingencies and events as defined within planning criteria.

- Prevent cascading outages or system failure following credible contingencies and events.

These criteria are intended to be used as a general guide in planning the three islands' transmission systems, for which transmission needs for reinforcement, enhancements and mitigations will be determined.

The Moloka'i and Lana'i system do not have a transmission system, and therefore, do not have a transmission planning criteria. However, in this study, maintaining system dynamic stability for a three-phase bolted fault with 2 seconds duration and for a single-phase to ground fault with 40 ohm fault impedance and 20 seconds duration is used as criteria to evaluate system dynamic stability.

3.3.1 Thermal limits

For the O'ahu transmission system, with any generating unit offline for maintenance, all transmission system elements will operate within their normal ratings while mainaining voltage leves within planning criteria limits for any single transmission element outage. If any transmission line out of service for maintenance happens together with any generating unit offline for maintenance, all trasmission system elements will operate within their emergency ratings while maintainning voltage levels within their limits. Any generating station must be able to operate at maximum normal rating with no transmission system element loading exceeding its emergency rating while maintaining voltage levels within limits for any of the transmission system element outages.

For Maui and Hawai'i island, with any generating unit offline for maintenance, outage of any transmission system element or another generating unit will trigger remaining transmission system elements oprate within their emergency ratings. Simliar for any generation station operating at maximum normal rating, all transmission system element will operate at emergeny limit when there is a transmission elment outage.

3.3.2 Voltage levels

Transmission voltage levels shall be kept within the prescribed limits for any condition for which the transmission system is planned. These limits apply after automatic corrective action has been taken by LTC and/or switched capacitors. For O'ahu, 138 kV system voltage should be maintained between 126.5 kV to 145 kV, and 46 kV system voltage should be maintained between 45 kV and 48 kV. For Maui and Hawai'i island, 69 kV system voltage should be maintained between 62.1 kV and 72.5 kV, 34.5 kV system voltage should be maintained between 31.05 kV and 36.2 kV, and 23 kV system voltage should be maintained between 20.7 kV and 24.15 kV.

3.3.3 System stability

For all three systems, system stability includes steady state voltage stability, control stability, rotor angle stability and frequency stability. Accoridng to previous studies, system critical clearing time ("CCT") is recommended to be no longer than 24 cycles. In recent system dynamic stability studies, frequency stability study is the focus. According to these planning criteria, for the O'ahu transmission system, under frequency load sheding ("UFLS") is not allowed for planning events P1 to P5; for the Maui and Hawai'i island transmission system, certain amount of UFLS is allowed for single contingency with generation trip and multiple contingency.

3.4 Distribution Criteria

During the analysis stage of the distribution planning process, distribution planning criteria have been established as technical guidelines to ensure that the distribution system has adequate capacity and reliability to accommodate forecasted load and DER growth.

3.4.1 Normal Conditions

The distribution system, or a subset of the distribution system, is operating under normal conditions when all circuits and transformers in the subject area are configured as designed. Under this normal condition, the circuits and transformers are planned to have adequate capacity to serve electrical peak load, and with DER, the circuits and transformers are also planned to be adequate for the backflow of generation caused by the DER.

3.4.2 Contingency Conditions

The distribution system, or a subset of the distribution system, is operating under contingency conditions when a single circuit or transformer is out of service. This is also referred to as an N-1 scenario. A circuit or transformer may be out of service or de-energized because of equipment failure or planned maintenance. As such, a level of capacity must be available on the circuits and transformers to be available to serve customers during these N-1 scenarios. For instance, because an adjacent circuit or transformer is often used as a backup source for another circuit or transformer, N-1 scenarios also need to be analyzed to ensure that back-tie capacity is available.

3.4.3 Normal and Contingency Overloads

Normal overload occurs when the load exceeds the normal equipment rating of distribution circuits or distribution substation transformers under normal operating conditions. Normal overload is identified by comparing the forecasted load with the equipment rating.

Contingency (N-1) overload occurs when the load exceeds the emergency equipment ratings of a piece of equipment under scenarios when other equipment fail or is out for maintenance. Contingency overload is identified by studying the forecasted load for possible contingency situations.

3.4.4 Overload and Voltage Issues

The overload of a circuit or transformer may lead to overheating issues that will damage equipment; hence, overloads are considered thermal issues. When circuit or transformer loading exceeds the equipment thermal ratings, damage may occur to the equipment. This damage may lead to extended service interruptions and high maintenance expenses.

In addition to thermal overloads, the electrical system is also analyzed to ensure that there are no voltage issues. In general, the voltage level must be maintained within 5% of the nominal voltage at any point on the distribution system (primary and secondary)[33].Low or high voltage may lead to power quality issues that could damage customer-owned equipment or cause nuisance electrical issues, such as flickering light or tripping of equipment.

3.5 Existing Customer energy resource programs

Our plans integrate our vast offerings of customer programs that have contributed towards the high penetration of customer resources that include private rooftop solar, battery energy storage, direct load control (i.e., demand response) and community based renewable energy offerings. The resources acquired through these programs are an important and significant portion of our renewable portfolio.

Our programs are predominantly made up of less than 100 kW solar systems:

Net Energy Metering ("NEM"): is closed to new applicants. However, customers with renewable energy systems (predominantly private rooftop solar) are credited on their electric bill the retail rate of electricity for every kWh exported to the grid.

Net Energy Metering Plus ("NEM Plus"): allows current NEM customers with a signed agreement to add additional non-export capacity to their system.

Standard Interconnection Agreement ("SIA"): is designed for larger customers who wish to offset their electricity bill with on-site generation. No compensation is allowed for exported energy.

Smart Export: customers with a renewable system and a battery energy storage system have the option to export energy to the grid from 4 p.m. – 9 a.m. Systems must include grid support technology to manage grid reliability and system performance.

Customer Self-Supply ("CSS"): intended only for private rooftop solar installations that are designed to not export any electricity to the grid. Customers are not compensated for any export of energy.

Customer Grid-Supply ("CGS"): participants receive a Commission-approved credit for electricity sent to the grid and are billed at the retail rate for electricity they use from the grid. The program remains open until the installed capacity has been reached.

Customer Grid-Supply Plus ("CGS Plus"): systems must include grid support technology to manage grid reliability and allow the utility to remotely monitor system performance, technical compliance, and

[33] Hawaiian Electric is required to manage the voltage to within limits prescribed in Rule No. 2 Character of Service. *See* https://www.hawaiianelectric.com/documents/billing_and_payment/rates/hawaiian_electric_rules/2.pdf

if necessary, control for grid stability. Participants receive a commission-approved credit for electricity sent to the grid.

Community Based Renewable Energy ("CBRE"): provides an additional option for customers who are not already enrolled in a DER program to benefit from electricity generated by a renewable energy facility in their utility service territory.

Interim Time-of-Use ("TOU-RI"): an opt-in program for residential customers that is designed for customers to save money if they use more power during the day -- when solar energy production is the highest -- and less at night.

The capacity of our customer programs is illustrated in Figure B-25.

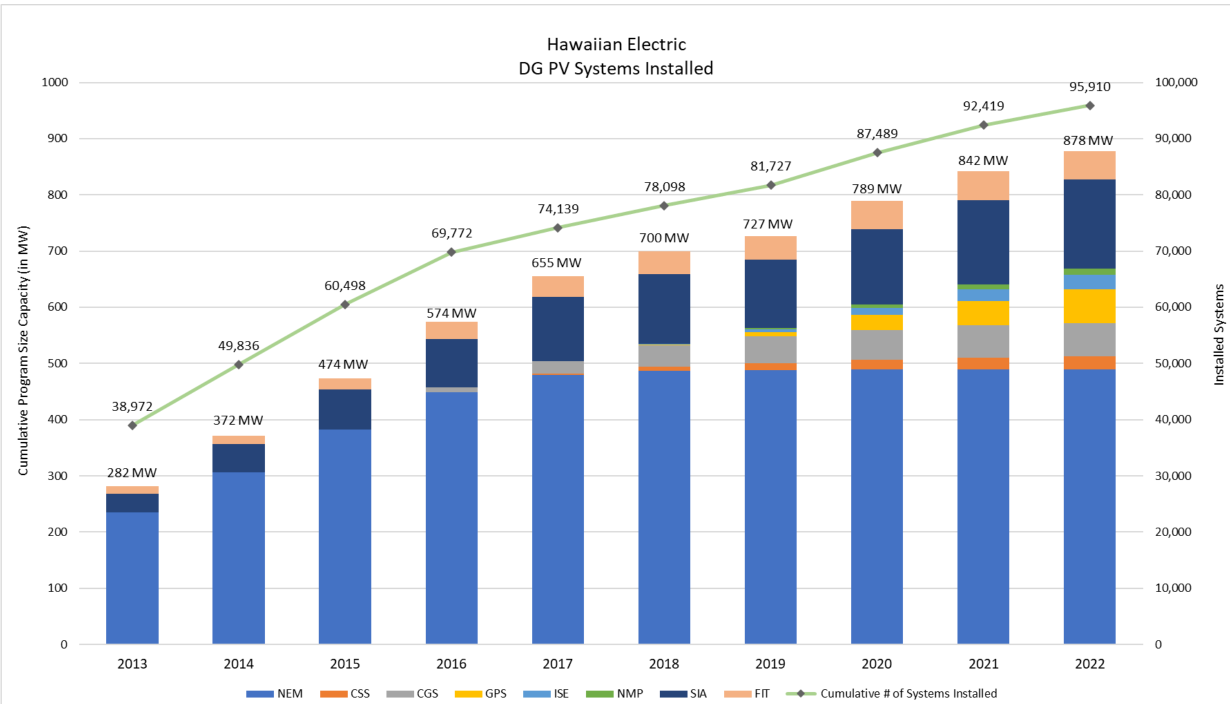

Figure B-24. Hawaiian Electric DGPV Systems Installed

Grid Service Programs

In addition to customer programs where customers may export excess energy that they do not consume, we also have program offerings where customers can provide certain grid services to the grid. Customers are compensated for the provision of services which may be administered through a third-party aggregator or Hawaiian Electric. We have several grid service purchase agreements with third party aggregators. Many of these programs are not fully subscribed as aggregators continue to recruit customers. We also have legacy demand response programs.

Grid Services Purchase Agreements – Actively Recruiting

GSPA contracts specify the delivery of Capacity Reduction, Capacity Build, and Fast Frequency Response Grid Services. These services are delivered by aggregators who we have contracted with. We currently have two GSPAs on O‘ahu that have been actively enrolling participants since 2020. We have two active GSPAs on Maui that have been actively enrolling participants since 2020, and have one GSPA on Hawai‘i Island that has been actively enrolling participants since 2022. We continue to focus on supporting and aiding the aggregators to achieve their contracted target amount.

Grid Services Purchase Agreements – Recent and on-going procurements

We conducted a third round of GSPA procurements for the island of O‘ahu. This resulted in a negotiated contract with an aggregator to deliver 97.4 MWs of grid services.

We recently issued a Maui GSPA RFP to acquire Grid Services to address the recently advanced end-of-life forecast for the four 12.5 MW Mitsubishi-MAN generating units on Maui.

Battery Bonus – Actively Recruiting

The Battery Bonus Program on Oahu and Maui is designed to provide scheduled export of power for 2 hours during the evening peak intended to address times where generation reserves may be tight due to the retirement of the AES coal plant and the forthcoming retirement of generation on Maui. The program pays upfront and monthly incentives to customers in exchange for export during the peak demand period for electricity. The program is currently limited to 50 MW on Oahu and 15 MW on Maui island.

Fast Demand Response (Fast DR)

On Oahu, the Fast DR program currently has a capacity of 4.0 MW from 16 customers in the military, hospitality, condominium, education, and office sectors. On Maui, the targeted 2023 impact for the Fast DR Program is 4.3 MW (customer level), and currently has 27 participants from the hospitality, water, education, and retail sectors.

EnergyScout Residential (RDLC) - In Maintenance (O‘ahu)

The residential direct load control program currently has approximately 29,000 water heaters and 3,700 air conditioner direct load control devices enrolled with 26,000 participants for a capacity of 13.6 MW. We will continue existing operations to maintain customer participation and MW impacts for RDLC.

EnergyScout Commercial (CIDLC) - In Maintenance

The commercial industrial load control program currently has a capacity of 11.4 MW from 25 commercial and industrial customers in the military, hospitality, condominium, education, and office sectors. In addition, the small business direct load control program currently has a capacity of 1.0 MW from 175 small and medium business customers in the retail, restaurant, and office sectors. We will continue the existing operations to maintain customer participation and MW impacts for CIDLC.

EnergyScout Residential Technology Replacement

We are currently pursuing a programmatic solution to transition the existing EnergyScout Program participants to a new program(s) technology that offers grid service delivery. Specifically, existing EnergyScout Program participants would potentially be able to deliver a variety of grid services by relying on smarter, two-way communicating devices/equipment.

We issued an RFP in early 2022 and selected multiple vendors to update technology for its EnergyScout program. The RFP requested that vendors provide a replacement technology to the current direct load control device, a software system to manage and aggregate the fleet of water heaters, and an administrator to enable and monitor the replacement of the existing devices and provide ongoing program maintenance.

3.6 Existing generation portfolio

The current generation portfolio contains a mix of utility-owned generation as well as generation from independent power producers (IPPs) that includes, solar, wind, geothermal, hydro, biofuel and diesel powered generators, along with oil fired steam generation. This section describes our current generation portfolio on each island that we serve.

3.6.1 O'ahu

Utility-Owned Generation

Kahe Generating Station. The Kahe generation station has six steam units, all baseload generation, with a combined nameplate capacity of 650 MW, with 606 MW net generation. These are our most efficient units. The station has black start capability.

Waiau Generating Station. The Waiau generating station has eight units: six are steam units and two are diesel. Two are baseload units; four are cycling units; and two are quick-start combustion turbines. Their combined nameplate capacity is 500 MW, with 474 MW net generation. The station has black start capability.

Campbell Industrial Park (CIP). The CIP generating station has one combustion turbine, CT-1, which runs on diesel but capable of running on biodiesel. It provides 129 MW net firm generation. The unit is both quick-start capable and black start capable. This peaking unit runs approximately 10% of the time to address peak load times.

Schofield Generating Station. The Schofield generating station has six combustion engines for a total of 48.6 MW which run on biodiesel. The individual units are quick-start capable and black start capable. The Schofield generation station also has the ability to power the U.S. Army facilities in an emergency for critical missions. In normal operations this unit serves the broader grid and is a used as a peaking unit.

Honolulu Generating Station. The Honolulu generating station, located in the downtown load center, has two steam units with a combined nameplate capacity of 113 MW, with 107 MW net generation. Both are cycling units. These units were deactivated in January 2014, and are expected to be retired by the end of 2023.

Our baseload units average 54 years of age, while the cycling units average 70 years. The combined average age of all steam units is 59 years. While our existing generation fleet does well in serving stable, predictable, consistent loads, they are not as capable as modernized generation in effectively managing system stability with higher levels of variable generation.

As the role of firm generation assets evolve, the technical and operational capabilities of these units must match their new use pattern. To meet the future requirements, many existing generators must be modified or replaced in order to cost-effectively supply supplemental energy, fast balancing services, and other requirements identified for reliable and secure power delivery in the future. Among other attributes, new assets need to have operational flexibility: the ability to start quickly, ramp up and down at high rates, and must be designed to regularly start and stop multiple times daily even after long periods of being offline. The baseload steam units in our fleet do not fully possess these characteristics and will need replacement with modern units that do.

Independent Power Producer (IPP) Generation

H-POWER. The Honolulu Program of Waste Energy Recovery (H-POWER) is a municipal solid waste refuse to energy plant that generates 68.5 MW of baseload, firm generation.

Kalaeloa. The Kalaeloa cogeneration (combined-cycle) plant burns LSFO to generate 208 MW of baseload generation.

3.6.2 Hawai'i Island

On Hawaii Island we currently own and operate 23 firm generating units, totaling about 181.6 MW (net, maximum capacity), at five generating stations and four distributed generation sites. Three steam units (fueled with No. 6 fuel oil–MSFO) are located at the Hill, and Puna generating stations. Ten diesel engine generators (fueled with diesel) are located at the Waimea, Kanoelehua, and Keahole generating stations. Our five combustion turbines (CTs–fueled with diesel) are located at the Kanoelehua, Keahole, and Puna generating stations. Two of the Keahole CTs are configured to operate in combined cycle with a heat recovery steam turbine. Four distributed generation diesel engines fueled with diesel fuel are located individually at the Panaewa, Ouli, Punalu'u, and Kapua substations (the Panaewa and Kapua units are temporarily located at Kapoho as part of a lava mitigation plan to serve customers potentially isolated by the flow, and will be restored for grid operation).

Two independent power producers (IPPs) provide firm capacity power to our grid. One is a combined-cycle power plant, Hamakua Energy Partners (HEP), owned and operated by Pacific Current; the other is a geothermal power plant owned and operated by Puna Geothermal Venture (PGV).

Our generation fleet has the following capabilities:

- Quick/fast start generation including simple cycle combustion turbines (SCCT) and ICEs that provide emergency replacement power and peaking generation, but at a higher cost than the larger resources. The simple cycle combustion turbines can be used as black start resources.
- Combined-cycle units, comprised of two CTs, two HRSGs, and one ST with high efficiency and relatively low cost. These assets provide cycling capability with a 1–2 hour start time, and have fast ramping capability.
- Older conventional steam units have offline cycling capability, but longer start-up times and less ramping capability when compared to the combined-cycle units.
- Geothermal IPP provides firm energy.

3.6.3 Maui County

In Maui County we own and operate three island electric grids on the islands of Maui, Molokaʻi, and Lanaʻi. Each island as its own unique physical grid design based on system load, demand, and customer needs. Our generation portfolio is composed of a mix of renewable and firm resources.

We generate the majority of our power from combined-cycle and internal combustion engine units, as well as a growing portfolio of renewable energy. Maui's total firm capacity is 251.7 MW (gross). Lanaʻi's total firm capacity is 9.40 MW (gross). Molokaʻi's total firm capacity is 15.18 MW (gross).

The Maui grid includes a growing portfolio of variable renewable energy that includes wind, solar photovoltaic, and hydropower. Our firm generation resources include centralized generating stations comprised of combined cycle and internal combustion engine units, oil-fired steam units, and biomass.

Maui Island's existing dispatchable generation fleet comprises two main power plants at Kahului and Maʻalaea. These plants include:

- Quick-start internal combustion engines (ICEs) that provide emergency replacement power and peaking generation.
- Combined-cycle units, comprised of two combustion turbines (CTs), two heat recovery steam generators (HRSGs) or once-through steam generators (OTSGs), and one steam turbine (ST) that provide high efficiency and relatively low cost cycling capability with a one- to two-hour start time, and fast ramping response. These combined-cycle units support the integration of variable renewables resources needed to achieve the 100% RPS goal by 2045.

Molokaʻi and Lānaʻi have existing dispatchable generation fleet which comprises quick-start internal combustion engines (ICEs) at Pālāʻau and Miki Basin, respectively. Molokaʻi also has a combustion turbine, also located at Pālāʻau.