BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAIʻI

- - - - - - - - In The Matter of - - - - - - - -	)	
	)	
PUBLIC UTILITIES COMMISSION	)	DOCKET NO. 2018-0165
	)	
Instituting a Proceeding to Investigate	)	
Integrated Grid Planning	)	
	)	

THE HAWAIIAN ELECTRIC COMPANIES'

GRID NEEDS ASSESSMENT METHODOLOGY REVIEW POINT

Book 2 of 2

Filed November 5, 2021

EXHIBIT 2

Transmission Renewable Energy Zone Study

Hawaiian Electric
Transmission Renewable Energy Zone (REZ) Study

November 2021

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1. Executive Summary

As part of the Integrated Grid Planning process, the Company has been undertaking an industry-leading approach, incorporating stakeholder and community input to shape the grid of the future. Within this process, the Renewable Energy Zone study was commissioned to understand the technical requirements to further increase grid-scale renewable energy in Hawaii, as well as to develop initial cost estimates of additional transmission capacity to incorporate in long-term resource planning analyses. This study focuses on the transmission system, which is the backbone of the electric grid allowing transfer of energy through long distances and throughout each island.

Implementing grid-scale renewable energy is not a plug and play exercise. The transmission system is approaching capacity limitations in areas where renewable resources are richer placing the Company and the State at somewhat of an inflection point. In order to add significant amounts of new renewable resources will require new transmission capacity to connect the current transmission system to these resources or to increase the capacity of the transmission system to harness electrical power from areas in which renewable resources are available and transmit that power to the rest of the island. Planning and building major transmission to support a 100% renewable future requires decade(s) of effort, and must be started now.

Ultimately, the success of implementing the identified transmission solutions, or other to-be-determined solutions, will require alignment with the community, stakeholders, and the State. This study represents the beginning of a process, and is expected to be used as a catalyst of further discussions regarding the future of Hawaii's electric system. With community, stakeholder, and the States' input and support, the Company anticipates future iterations and refinements of this study to develop realistic, achievable plans to support the increase of renewable energy.

Although this represents an early stage in the overall process, the following findings can be used to inform future iterations of analysis as plans are developed.

1. On Oahu, interconnection of REZ groups 1 to 7 (West, Central, East, and Southeast regions) requires minimum Transmission Network Expansions[1]. REZ Group 8 (Wahiawa, North Shore area) has a vast amount of renewable energy potential (over 1 GW), but realizing its full potential will require significant Transmission Network Expansions.
2. Two separate analyses to interconnect up to 600 MW and 400 MW of off-shore wind at Ko`olau, Halawa, Iwilei and Kahe substations (Oahu) was performed. The study assumed off-shore wind was interconnected after REZ groups 1 to 8.
    a. Interconnecting up to 600 MW of off-shore wind was found to be feasible only at Ko`olau substation. Additional Transmission Network Expansion requirements were also needed beyond those required to interconnection REZ groups 1 to 8.

[1] Transmission Network Expansions are transmission system upgrades not associated with a particular REZ group, and are required to support the flow of energy within the transmission system and provide generation dispatch flexibility.

   b. Interconnecting up to 400 MW offshore wind still resulted in Ko`olau substation as the only feasible option for interconnection. No additional Transmission Network Expansions are required beyond those are required for interconnecting REZ groups 1 to 8.
3. On Maui, development of REZs should consider geographic diversity, and be planned in to diversify resources among west, south and central Maui. Interconnection of REZ Groups 1, 2, 3 and 4B1 (West and Central regions) requires limited Transmission Network Expansion. Interconnection of REZ 4A and REZ 4B2 (South and North regions) causes significant 69 kV conductor overloading, which requires a Transmission Network Expansion of South and Central Maui 69 kV system.
4. On Hawaii Island, similar to Maui, REZs should consider geographic diversity, and be planned to diversify resources among the east and west of Hawai`i island. The interconnection of REZ Groups 3, 4 and 5 (Central, North, and South regions) requires least Transmission Network Expansion.

2. Introduction

Hawaiian Electric has commenced a study to identify transmission infrastructure necessary to accommodate the large blocks of grid-scale renewable energy on the islands of Oʻahu, Maui, and Hawaiʻi Island. The objective of this study is to assess the technical feasibility and Transmission needs (for capacity) to interconnect additional amounts of renewable energy to achieve our State's RPS, and provide initial cost estimates. These costs will be incorporated in the Integrated Grid Planning (IGP) process to develop resource portfolio plans.

The existing transmission infrastructure is approaching its capacity limitations for which they were designed with the significant increases in Renewable Energy projects (e.g., RFP Stage 1 and 2). The Company is making efforts to maximize the utilization of existing transmission capacity, but in many cases, will not be enough to take advantage of the renewable energy potential in key areas of each island we serve. In certain areas, such as the West side of Hawaii Island, the capability to add grid-scale renewable energy is limited due to the power flow within the West of the Island, as well as power flow from West to East of Hawaii Island. Within the framework of the Company's Integrated Grid Planning process, the Company is taking a bold step to begin the conversation with stakeholders and the community to communicate, determine, and plan the requirements to attain higher levels of renewable energy.

This study represents an initial step in developing transmission infrastructure required to further increase utility-scale renewable energy. The process to develop Renewable Energy Zones (REZ) is outlined in Figure 1 in which this study covers steps 1-3. The Company anticipates multiple iterations of each step with stakeholder and community members as the process progresses. A draft of this study was presented to IGP stakeholders in October 2021, and the Company plans to pursue further stakeholder and community outreach upon filing this study.

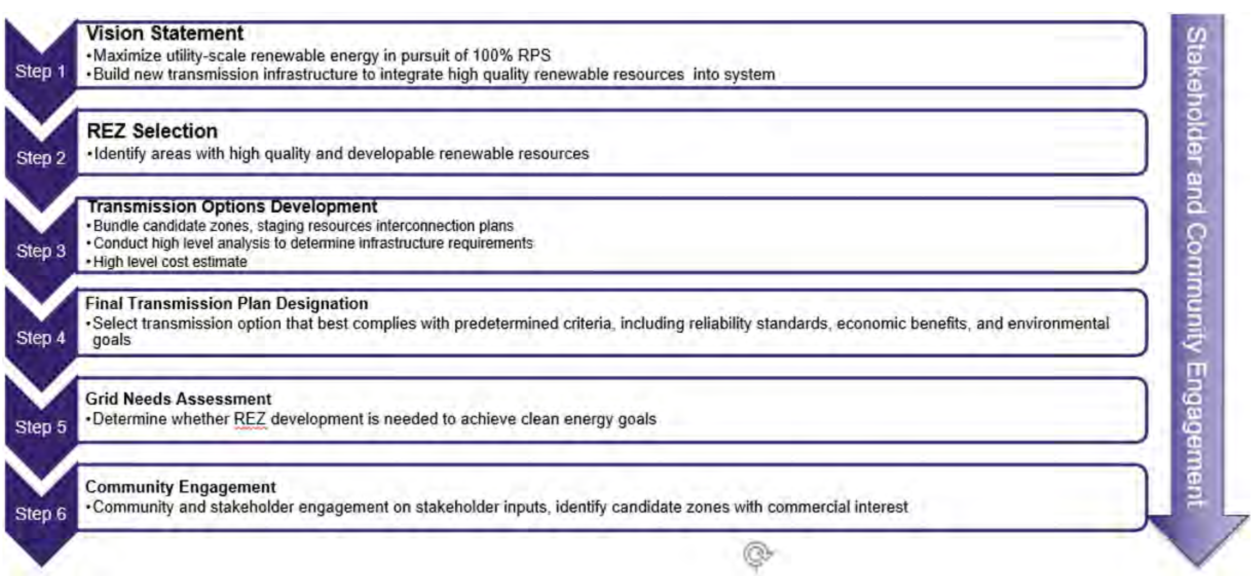

Figure 1 Transmission Renewable Energy Zone Planning Process

There are multiple uses for the information found in this study:

- The study will allow the Company and stakeholders to get an initial understanding of the capabilities of the existing transmission system, as well as transmission upgrade options to accommodate future amounts of grid-scale renewable energy.
- This information can be used to inform policy making discussions on land use and how best to use the limited land resources for competing purposes (e.g., agriculture, housing, energy, preservation, etc.).
- A future REZ plan developed through stakeholder and community outreach will serve as a long-term blueprint to align to. As resources are added to the system, transmission upgrades may be incrementally added in alignment with an overarching development plan.
- This information will also be used within the IGP process; including developing future resource costs and schedules, as well as educating and engaging with communities to gather feedback on these potential plans, while contemplating tradeoffs under various decarbonization and renewable goals.

As an example, there are high amounts of solar potential on the west and north ends of O`ahu; however, there are currently no transmission lines in those areas. Creating a REZ by extending transmission lines to these areas would facilitate further development of renewable energy. These transmission requirements and cost to interconnect various renewable energy zones will serve as an input into the RESOLVE model, which is the Company's tool to determine resource plans based on economic and operational requirements. The RESOLVE model will then be allowed to select a specific renewable energy zone based on the cost of the resource and transmission infrastructure required to interconnect that zone.

The study, based on steady-state power flow analyses, assesses the capacity of the existing transmission system and identifies the cost of different transmission upgrade options to interconnect the identified megawatt capacity of each renewable energy zones. The NREL potential study (Scenario Alt-1)[2] is used as a basis for identifying potential capacity within the identified zones. The Company acknowledges there are differing opinions from stakeholders regarding these assumptions; however, for purposes of this study, the scenario provides an appropriate capacity potential to determine the transmission requirements.

The study will identify transmission capacity requirements (i.e., major transmission lines and substations) necessary to facilitate the transfer of power (regardless of the generating resource technology) from the REZ to the rest of the system. For consistency and clarity, there are three terms used throughout the report:

- **Total REZ Upgrades**, which represents the collective of Transmission Network Expansions and REZ Enablements to interconnect all REZ groups.

[2] *See* Hawaiian Electric Revision to Updated and Revised Inputs and Assumptions, Section 5.1.1, August 19, 2021. Dkt. No. 2018-0165.

- **Transmission Network Expansions**, which are transmission system upgrades not associated with a particular REZ group, and are required to support the flow of energy within the transmission system and provide generation dispatch flexibility.
- **REZ Enablements**, which are new or upgraded transmission lines and new or expanded substations required to connect the transmission hub of each REZ group to the nearest transmission substation.

Costs for interconnection requirements that are developed by specific projects are not included in this analysis (e.g., generation-tie lines). REZ enablement is used to create a system architecture that establishes a central point for interconnection in different areas of the island (i.e., a hub and spoke model). This will create a more efficient interconnection process and proactively identifies points of interconnection for future projects. It also mitigates technical issues associated with past practices of allowing individual projects to build their own substation, effectively "cutting" or segmenting a transmission line in multiple locations. The IGP Technical Advisory Panel (TAP) agreed "with the premise that it is preferable to provide planned interconnection points for renewables rather than piecemeal tapping of transmission lines as is currently being done (see Appendix B)." General steps to complete the REZ study for the Grid Needs Review Point filing is shown in Figure 2.

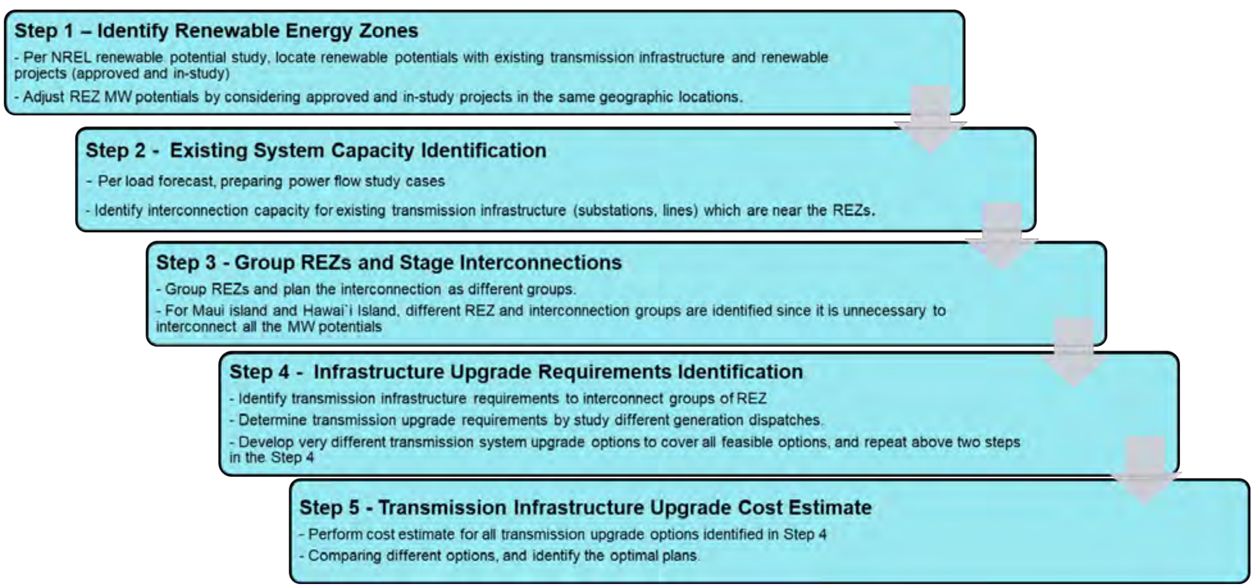

Figure 2 Transmission Renewable Energy Zone Study Procedures

3. Key Assumptions and Methodology

3.1. Assumptions for Power Flow Study

The year 2040 was used as a planning target, and the forecasted load in MW is provided in Table 3-1. The starting point for developing the potential interconnection in MWs was the NREL PV-Alt-1 scenario, which was adjusted as described in Section 3.2 to the Adjusted Potential Interconnection. The Adjusted Potential Interconnection MW represents the aggregated MW-ac size of all potential grid-scale renewable projects in the REZ. Although the study remains technology agnostic, should there be high amounts of non-firm type resources added, consideration was made to supply the forecasted peak load from various zones and at much higher levels of supply vs. load. Therefore, to maintain flexibility of dispatch for all REZ, different dispatch scenarios are created to determine system upgrade requirements in order to achieve the potential interconnection.

Table 3-1 2040 Load Forecast and Potential Renewable Interconnection for Studied Islands

Island	Total Renewable Potential (MW)[3]			2040 Forecasted Peak Load (MW)	Adjusted Potential Interconnection (MW)
	Utility Scale Solar	On-Shore Wind	Off-Shore Wind		
Oahu	3,344	256	600	1,400	3,344 + 600
Maui	13,507	767	N/A	287	847/872
Hawaii	76,056	5,037	N/A	216	720/830

Other key assumptions used in the study, include:

- IGP Inputs and Assumptions were used to inform the study. Specifically, the thermal generation retirement schedule[4], load forecast[5], and NREL Solar and Wind potential[6].
- 2040 evening peak load scenario is selected for the study as a 20-year horizon is aligned with a long-term planning scenario. The forecasted load does not include any centralized

[3] The capacity of each zone was adjusted from the NREL Alt-1 scenario to subtract the capacity of existing or approved solar projects.
[4] Ibid, Section 8.
[5] Ibid, Section 4.1.
[6] Ibid, Section 5.1.

standalone energy storage charging load. Distribution-level DER contribution is not considered in this study.

- The study assumed the new grid-scale renewable energy resources were paired with Battery Energy Storage Systems (BESS) which provide flexibility of dispatch; however, the study reviews capacity of the transmission elements (lines and transformers), so other types of resources such as non-inverter-based resources (e.g., synchronous machines) may also be interconnected within these Renewable Energy Zones.
- All grid scale renewable projects (including existing projects) can provide lagging 0.95 to leading 0.95 power factor reactive power capability anytime. When necessary, available fossil plants are also dispatched for reactive power support.
- To determine Transmission Network Expansions, for all studied dispatches, higher priority is assigned to dispatch generation in REZ and existing projects and fossil plant MW generation are dispatched only when it is necessary.

The study was performed through single snapshot power flow without performing a time series study. Therefore, the following issues are not addressed in this study, but can be evaluated in future iterations of plans and respective studies:

- Non-Transmission Alternative (NTA), such as centralized standalone energy storage system, is not considered in this study to defer any Transmission Network Expansion.
- Operational mitigation, such as generation curtailment, is not considered in this study, which can be used as an alternative for transmission infrastructure upgrade.
- The study only focuses on the system steady state capacity evaluation, but not including voltage optimization, dispatch optimization, loss minimization or stability study. All these aspects can be addressed in the further study after getting feedback from stakeholder about the current study.
- Cost estimates included in this study includes the REZ Enablement and Transmission Network Expansions identified in this study only. Other requirements that require further detailed studies and evaluation such as protection upgrades, SCADA system upgrades, control systems, etc. are not included in the cost estimates in this study.

3.2.Assumptions for Renewable Potential

The goal of the study is to determine the transmission requirements to support the integration of renewables based on certain potentials. The basis for the potentials were provided by the NREL solar and wind potential, as described in the Company's filing on August 19, 2021 under docket no. 2018-0165, *Hawaiian Electric Revision to Updated and Revised Inputs and Assumptions*, Section 5.1.1. The renewable potential identified in the NREL study garnered feedback and discussion among the IGP Stakeholder Technical Working Group, which based on the feedback provided, an alternative scenario (Alt-1) was created to address feedback provided. Section 5.1.1 states:

> *Taking into consideration the various viewpoints, the Company will use the Alt-1 scenario for wind and solar potential for various scenarios. The Company will also use*

> *this Alt-1 scenario in developing transmission infrastructure needed to develop renewable energy zones, as discussed in the following Section 5.2. The Alt-1 scenario excludes DoD lands but includes development on land with slopes up to 30%.*
>
> *It is worth noting that there is substantial overlap between areas with solar resource potential and wind resource potential. And the same system infrastructure can be used to interconnect both wind and solar resources and transfer the renewable energy to the other locations of the system.*

As provided in the Company's filing, the PV-Alt-1 scenario was used as a basis for developing the renewable energy zone potential interconnections. Using this scenario is appropriate for this REZ study as (1) the study is technology agnostic, as it studies the injection of MW capacity on transmission lines and substations to determine the infrastructure needed to add these potential amounts; and (2) PV-Alt-1[7] and Wind-Alt-1[8] scenarios largely overlapped with Solar potentials at higher levels than Wind potentials (see Figure 3).

[7] *See* https://nrel.carto.com/u/gds-member/builder/4d570d92-d17c-4bba-b592-8f4e55446d50/embed
[8] *See* https://nrel.carto.com/u/gds-member/builder/49af7cb6-fbd7-4278-8ec9-a1663a910f8c/embed

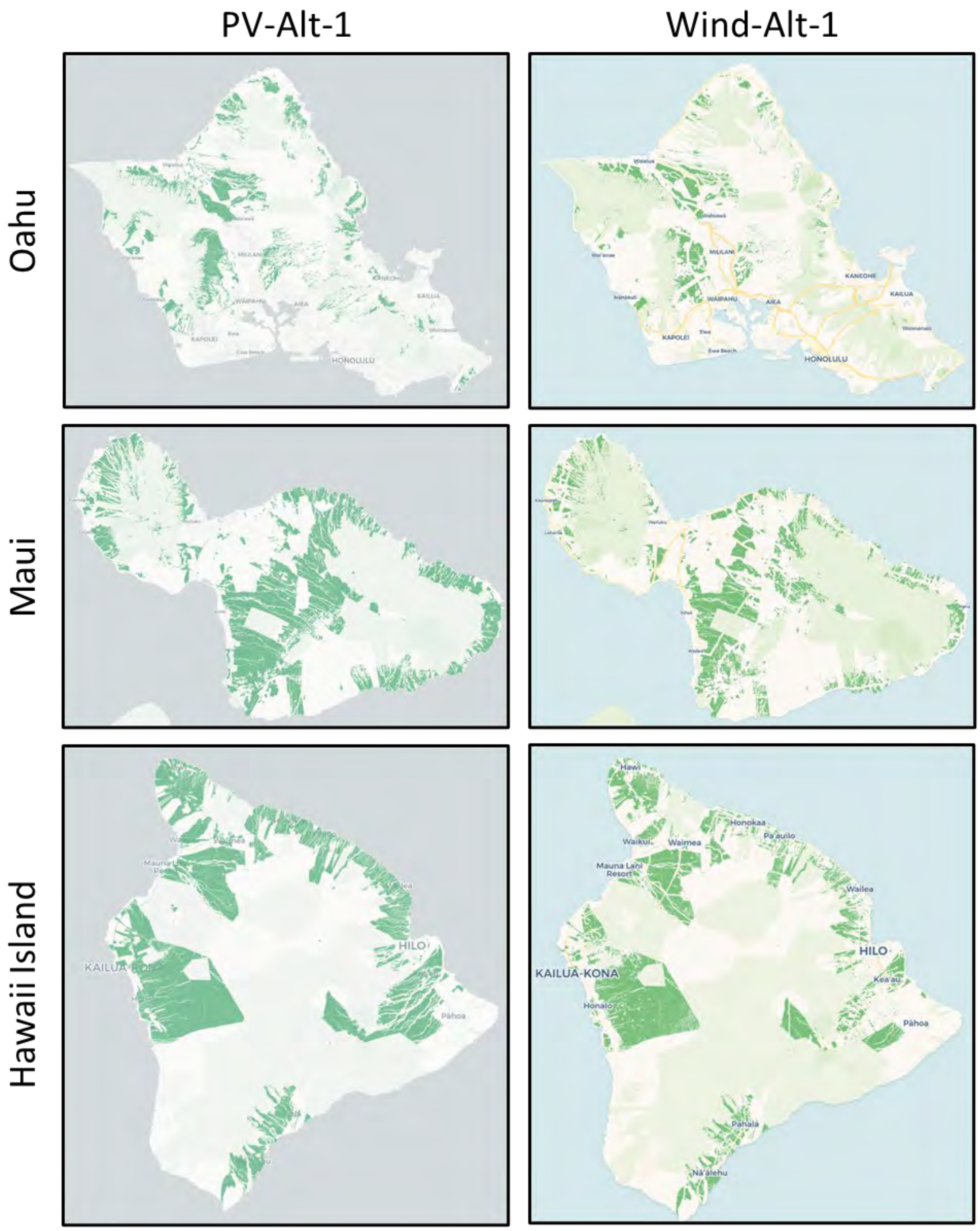

Figure 3 NREL PV and Wind Potential by Island (in dark green)

3.3. Assumptions for Cost Estimate

Transmission infrastructure upgrades are categorized as two parts in this study: 1) REZ Enablement which includes interconnecting the generation from the REZ to the system (e.g. switching station, transmission line extension, breaker-and-a-half (BAAH) and related substation expansion) and 2) Transmission Network Expansions which includes existing transmission system upgrades necessary to facilitate the transfer of energy throughout the system (e.g. re-conductor of existing transmission line, adding new transmission line between existing substations and related purchasing new right-of-way, adding new BAAH and substation expansion). The following assumptions are used for cost estimate in this study.

Regarding the design of interconnection facility to interconnecting the REZ groups to the transmission system, according to the Company's transmission planning criteria single-point failure capacity limit, trip of one gen-tie cannot cause a loss of centralized generation higher than 135 MW on O`ahu, 20 MW on Maui island, or 30 MW on Hawai`i island.

For REZ groups with high MW potentials, REZ Enablement cost for each interconnection with stepwise MW incremental are provided in this report, with assumption of fully realizing REZ MW potential. The cost estimates are provided on fixed MW increments based on the single-point failure capacity limit by island. The estimates are preliminary, will be impacted by many factors, such as interconnection MW size, relative location to interconnection substation or transmission line, new transmission infrastructure build-out status, substation available space, etc.

Table 2-2 Per Unit Costs and Assumptions

No.	Item	Cost
SUBSTATION ITEMS		
1		$8,800,000
2	138kV – Add 2 BAAH bays (including substation expansion)	$15,400,000
3	138kV – Add 2 BAAH bays (assumes space available within substation)	$14,400,000
4	138kV – New 4-bay BAAH substation	$35,200,000
5	138kV – Convert 4-breaker Ring bus to BAAH	$2,400,000
6	138kV – Line Relay Upgrade	$550,000
7	138kV – Add breaker	$660,000
8	345kV – New 4-bay BAAH substation	$70,500,000
9	345-138kV transformer, 450/600MVA	$9,800,000
10	345-138kV transformer, 600/700MVA	$10,900,000
11	138-69kV transformer, 100MVA	$4,900,000
12	138-12kV transformer, 10MVA	$1,600,000
13	69kV – One BAAH bay	$5,500,000
14	69kV – Add breaker	$550,000
15	69kV – Convert 4-breaker Ring bus to BAAH	$2,200,000

No.	Item	Cost
16		$2,200,000
17	23kV – New 2-bay BAAH substation	$10,900,000
18	Telecom infrastructure for new substation	$500,000
T&D ITEMS		
Overhead Accessible		
20		$7,310,000 / mile
21	138kV overbuild on existing lines (400ft spans)	$7,274,000 / mile
22	138kV OH reconductor (500ft spans)	$7,678,000 / mile
23	23kV-69kV OH accessible (250ft spans)	$1,179,000 / mile
24	23kV-69kV overbuild on existing lines (150ft spans)	$2,135,000 / mile
25	23kV-69kV OH reconductor (250ft spans)	$1,150,000 / mile
26	69kV OH upgrade to double bundle (250ft spans)	$1,785,000 / mile
27	345kV OH accessible (400ft spans)	$14,620,000 / mile
28	345kV overbuild on existing lines (400ft spans)	$14,548,000 / mile
Overhead Inaccessible		
30		$11,75,000 / mile
31	23kV-69kV OH inaccessible (250ft spans)	$1,984,000 / mile
32	345kV OH inaccessible (600ft spans)	$23,501,000 / mile
Underground		
40		$16,451,000 / mile
41	138kV riser pole	$887,000 each
42	46kV-69kV UG (400ft spans)	$8,736,000 / mile
43	46kV-69kV riser pole	$93,000 each
44	23kV UG (200ft spans)	$7,404,000 / mile
45	23kV riser pole	$91,000

Notes/Assumptions:
- Costs provided are 2025 dollars.
- Includes electrical and civil costs to engineer, procure, construct, and test all Company facilities.

No.	Item	Cost
- Costs listed in this table do not include project management (PM), permitting, land, or contingency costs. Costs for these items are added as percentages, if applicable, when calculating the total estimated cost of specific scenarios as laid out in subsequent sections of the report. These percentages are: o PM costs – 5% o Land/Permitting – 10% o Contingency – 25% - Accessible assumes accessible by vehicles. - Inaccessible assumes helicopters are needed for crews and materials. - Assumes land rights and permitting can be obtained for all new substations, expansion of existing substations, and routing of new transmission lines. - 138kV and 345kV assumes steel poles. - 69kV and below assumes wood poles. - Overbuild assumes all poles need to be replaced. - Reconductoring assumes an average cost between accessible and inaccessible - 138kV reconductoring assumes 50% of poles need to be replaced. - 23-69kV reconductoring assumes no poles need to be replaced. - Upgrade to double bundle (69kV) assumes all poles need to be replaced. - Substation expansion includes civil work to prepare site for installation of equipment. - Ring bus to BAAH bus conversion assumes substation is already built to BAAH dimensions.		

4. Study Methodology

The study methodology is described in Figure 4. As mentioned above, the study incorporates the renewable MW potential estimate based on the NREL potential study (Scenario Alt-1), and the forecasted load of year 2040 from the IGP forecast.

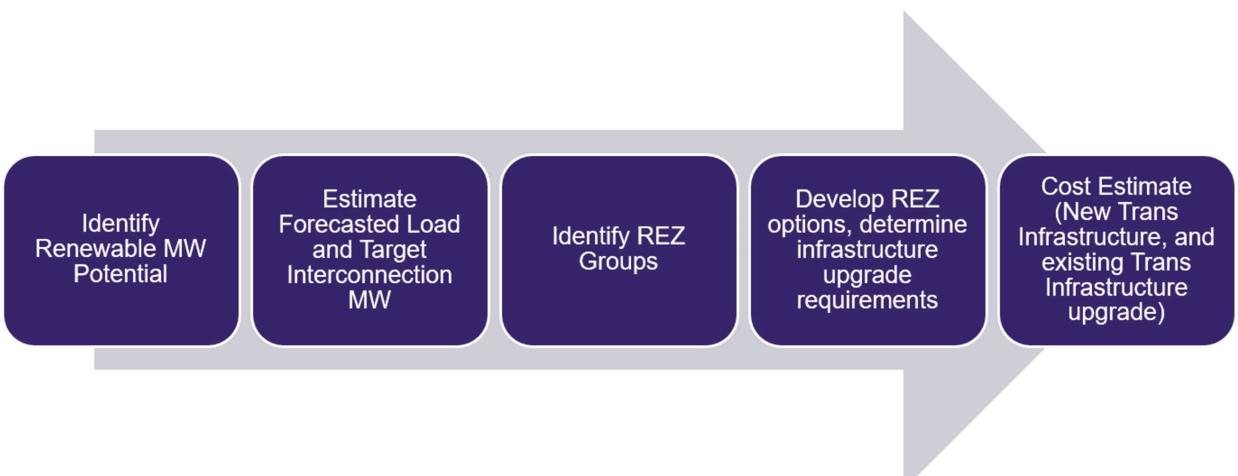

Figure 4 Transmission REZ Study Methodology

The REZ groups are identified by considering potential MW magnitude and geographic location related to existing transmission infrastructure. Based on the REZ groups, various system generation dispatches are studied to identify Transmission Network Expansion requirements for maintaining REZ dispatch flexibility. This is also the step in which different transmission upgrade options are considered. In the last step, cost estimates are produced for different transmission upgrade options for interconnection the same MW potential for stakeholders to review.

5. O‘ahu Transmission REZs

5.1. REZ Groups

The grid-scale MW potential located on O‘ahu is shown in green in Figure 5. The capacity of each zone is adjusted by subtracting the capacity of existing or approved grid-scale renewable projects (e.g., Stage 1, Stage 2 projects). According to the MW potential of renewable energy and the nearest existing transmission substations, 8 groups were created for the O`ahu study. The total potential MW capacity used for study is 3,344 MW on-shore renewable energy and 600 MW off-shore wind energy. Of the 8 REZ groups, only group 7 is considered to be interconnected through 46 kV sub-transmission lines. All remaining REZ groups are considered to be interconnected through the existing 138 kV transmission substations. The off-shore wind is considered to be interconnected to the system through Kahe 138 kV substation, Halawa 138 kV substation, Iwilei 138 kV substation or Ko`olau 138 kV substation.

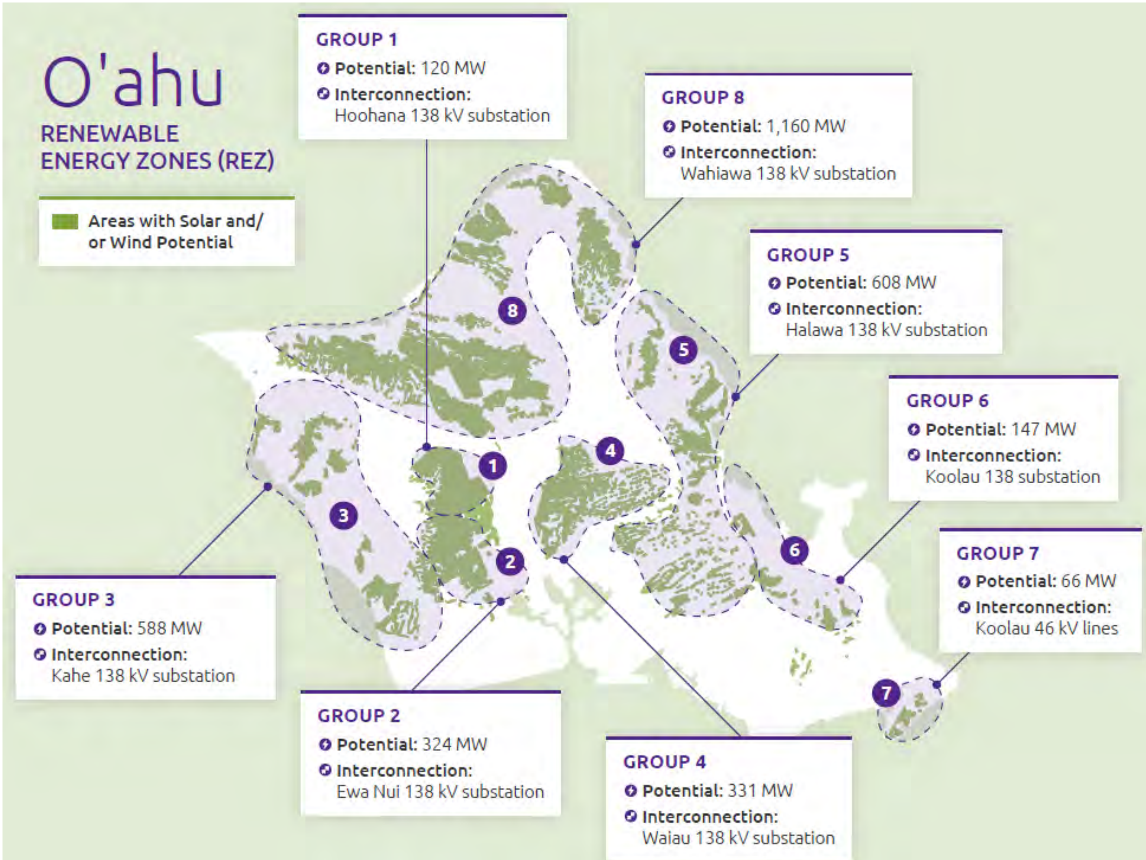

Figure 5 Transmission REZ groups with MW Potential on O'ahu Island (Off-shore wind not shown)

5.2. Studied Generation Dispatches

In order to identify Transmission Network Expansion requirements, various generation dispatches are designed by maximizing generation from potential and existing grid-scale generation in each REZ group. It is worth noting that the total required MW generation of each dispatch is always equal to 1,400 MW demand plus losses on the system. The studied dispatches are summarized in Table 5-1. The existing generation in the table refers to existing thermal generation and existing grid-scale BESS paired renewable projects. The existing generation is dispatched only if necessary. For example, in dispatch #1, generation in REZ Group 1 and 2 is not enough to supply the whole island load, and it is necessary to dispatch existing generation to supply load. In other scenarios, existing generation may be required to only supply reactive power.

To study the requirements of interconnecting 600 MW of off-shore wind, a sensitivity case was developed in addition to the dispatches listed in the Table 5-1. The study assumes the off-shore wind is added to the system after the interconnection of all eight REZ groups. The generation dispatches studied for the 600 MW off-shore wind are listed in Table 5-2. In the study results, the Total REZ Upgrade requirements for the 3,344 MW REZ interconnection and 600 MW off-shore wind interconnection are listed separately.

Table 5-1 Studied Generation Dispatches for O`ahu Transmission REZ

Dispatch #	Group 1 (120 MW)	Group 2 (324 MW)	Group 3 (588 MW)	Group 4 (331 MW)	Group 5 (608 MW)	Group 6 (147 MW)	Group 7 (66 MW)	Group 8 (1,160 MW)	Existing Generation
1	Full	Full	0	0	0	0	0	0	Supply remaining load
2	Full	Full	Full	0	0	0	0	0	Dispatch if necessary
3a	Full	Full	Full	Dispatch if necessary	0	0	0	0	0
3b	Dispatch if necessary	Dispatch if necessary	Full	Full	0	0	0	0	0
4	Dispatch if necessary	Dispatch if necessary	Dispatch if necessary	Full	Full	0	0	0	0
5	Dispatch if necessary	Dispatch if necessary	Dispatch if necessary	Full	Full	Full	0	0	0
6	Dispatch if necessary	Dispatch if necessary	Dispatch if necessary	Full	Full	Full	Full	0	0
7a	Dispatch if necessary	Dispatch if necessary	Dispatch if necessary	Dispatch if necessary	Full	Full	Full	300 MW	0
7b	Dispatch if necessary	Dispatch if necessary	Dispatch if necessary	Dispatch if necessary	Dispatch if necessary	Full	Full	800 MW	0
7c	Dispatch if necessary	Dispatch if necessary	Dispatch if necessary	Dispatch if necessary	Dispatch if necessary	Full	Full	Full	0
7d	Dispatch if necessary	Dispatch if necessary	Dispatch if necessary	240 MW	Dispatch if necessary	Dispatch if necessary	0	Full	0
7e	Dispatch if necessary	Dispatch if necessary	240 MW	Dispatch if necessary	Dispatch if necessary	Dispatch if necessary	0	Full	0
7f	Dispatch if necessary	240 MW	Dispatch if necessary	Dispatch if necessary	Dispatch if necessary	Dispatch if necessary	0	Full	0

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Table 5-2 Studied Generation Dispatches for 600 MW Off-Shore Wind Sensitivity Case

Dispatch #	Off Shore Wind (600 MW)	Group 1 (120 MW)	Group 3 (588 MW)	Group 5 (608 MW)	Group 6 (147 MW)	Group 8 (1,160 MW)	Existing Generation
8	Full, through Kahe 138 kV	0	Full	0	0	Dispatch if necessary	Dispatch if necessary
9	Full, through Ko`olau 138 kV	0	0	0	Full	Dispatch if necessary	Dispatch if necessary
10	Full, through Ko`olau 138 kV	Full	0	0	Full	Dispatch if necessary	Dispatch if necessary
11	Full, through Ko`olau 138 kV	0	Full	0	Full	Dispatch if necessary	Dispatch if necessary
12	Full, through Halawa 138 kV	0	0	Full	0	Dispatch if necessary	Dispatch if necessary
13	Full, through Halawa 138 kV	0	0	400	0	Dispatch if necessary	Dispatch if necessary
13	Full, through Halawa 138 kV	0	0	200	0	Dispatch if necessary	Dispatch if necessary

5.3.Studied Transmission Network Expansion Options

The largest REZ Group is Group 8 located north of the Wahiawa 138 kV substation with 1,160 MW potential. According to existing transmission infrastructure, the Wahiawa substation is the only transmission substation located in the area of REZ Group 8. The Wahiawa Substation is; however, designed differently than a generation switching station (e.g. Kahe 138 kV substation, Waiau 138 kV substation), as it was designed as a non-major load center substation which only has one BAAH bay (shown in Figure 6).

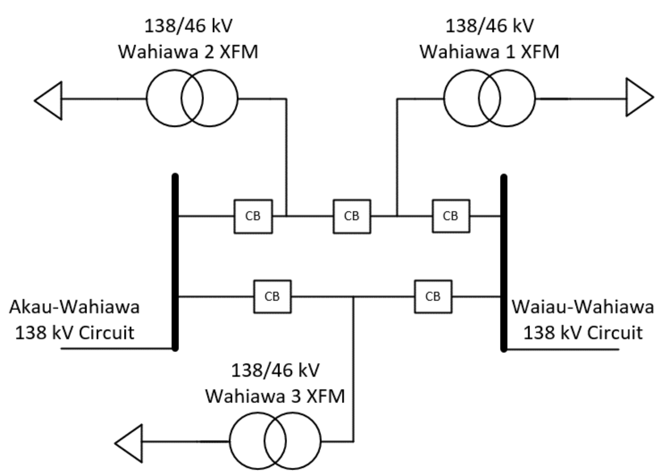


Figure 6 Current Wahiawa 138 kV substation single line diagram

The interconnection of Group 8 requires substantial transmission upgrades, as they are required to not only mitigate equipment overloading caused by the interconnection of other REZ or load growth, but also facilitate the export of 1,160 MW generation of REZ Group 8 from the Wahiawa 138 kV substation.

A steady-state power flow simulation provides transmission planners with certain values; such as voltage, current, etc. and used in conjunction with the transmission planning criteria, a determination is made on whether there were violations of criteria or not. In order to simulate future transmission system topologies, Transmission Network Expansion scenarios must be included in the transmission system model. The following three Transmission Network Expansion options were considered in this study, which were analyzed by using power flow simulations. Note that these do not include REZ Enablement which is necessary to interconnect renewable projects to the nearest transmission circuit or substation (see *Identifying Total REZ Upgrade Requirements* below):

- **Transmission Network Expansion Option 1** – new 138 kV transmission line between Kahe 138 kV and Wahiawa 138 kV substations (shown as Figure 7)

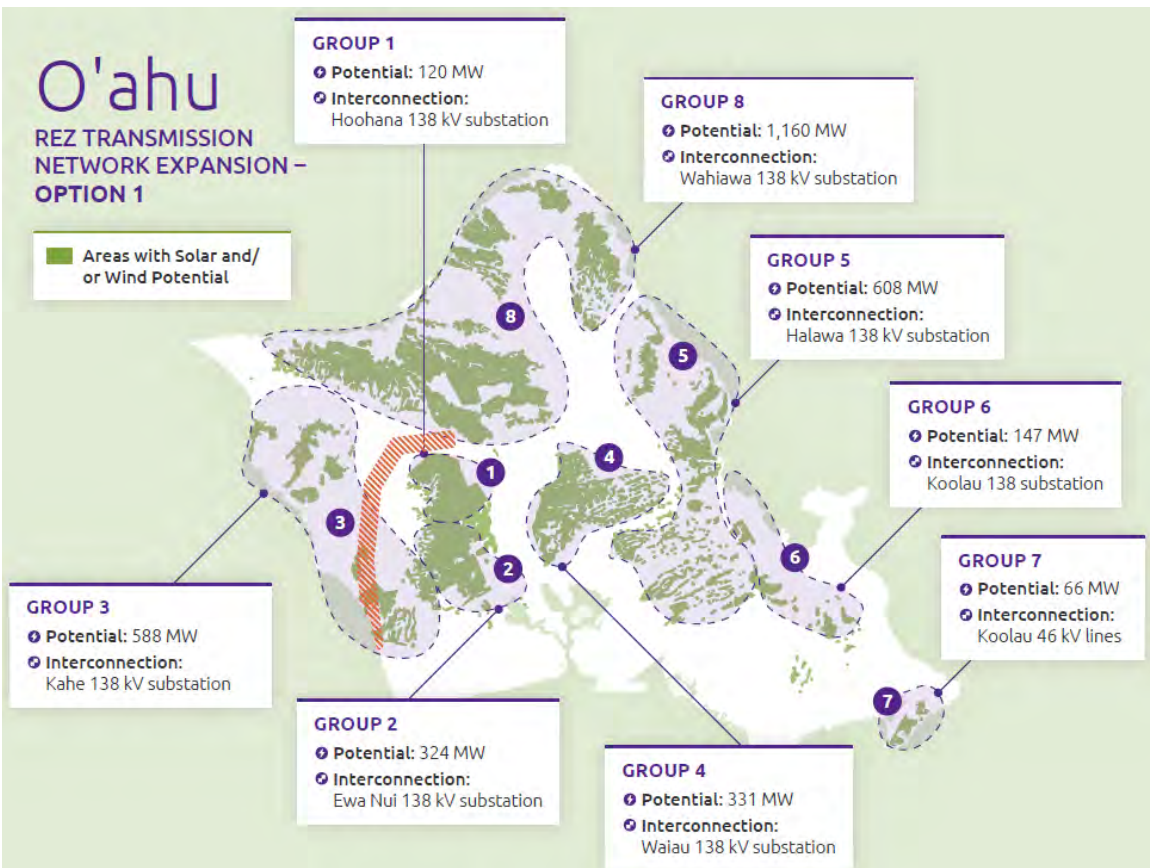


Figure 7 Option 1 - New 138 kV line between Kahe and Wahiawa substation (red shaded area)

- **Transmission Network Expansion Option 2** – re-conductor existing transmission circuits and adding new circuits if necessary (No figure provided)
- **Transmission Network Expansion Option 3** – new 345 kV loop between Wahiawa-Kahe-Waiau substations

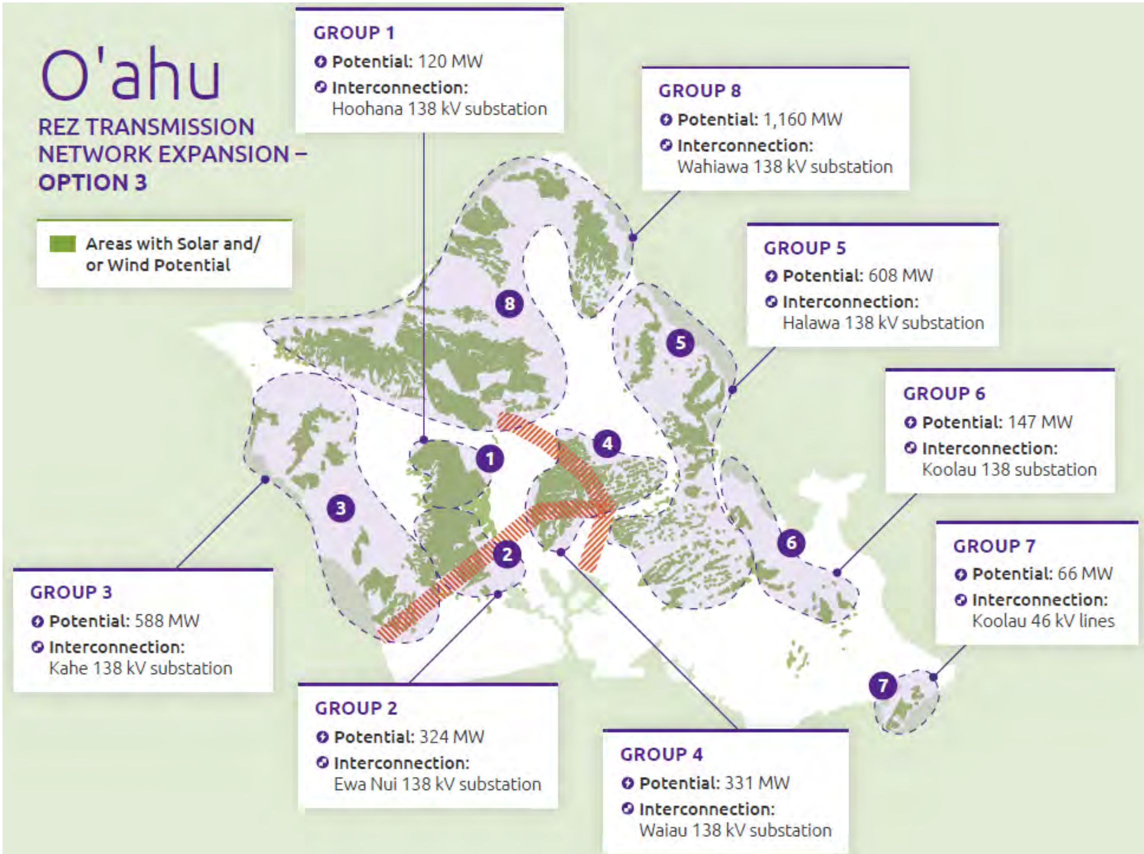


Figure 8 Option 3 - 345 kV loop among Kahe, Waiau and Wahiawa substations (red shaded area)

5.4. Identifying Total REZ Upgrade Requirements

The Transmission Network Expansion scenarios provided above provide a baseline system for studies. This section describes the Total REZ Upgrades required, which represent 1) Transmission Network Expansions, which include the scenarios provided above as well as additional upgrades required to mitigate criteria violations identified in accordance with the Hawaiian Electric transmission planning criteria and power flow study results, and 2) REZ Enablements, which are upgrades required to connect the center of each REZ to the nearest transmission substation. Examples of different types of transmission upgrades are listed in this section.

5.4.1. Transmission Network Expansions

Transmission Network Expansion requirements are identified through power flow study for dispatches listed in Table 5-1 and

Table 5-2. Per Hawaiian Electric's transmission planning criteria, both normal configurations and contingency configurations (N-1, and N-2) are considered in the study. According to the transmission planning criteria, equipment normal rating is used for both normal configuration and N-1 configurations study, and emergency rating is used for N-2 contingency configurations study.

Through the power flow study for the dispatches from dispatch 1 through dispatch 7a, it is concluded from the study results that there is no existing system equipment overloading issue. Therefore, the interconnection of REZ group 1 to the first 300 MW of Group 8 only requires the respective REZ Enablements, but not the Transmission Network Expansion to increase transmission capacity. Therefore, the three Transmission Network Expansion options listed in section 5.3 are considered only for interconnecting the entire 1,160 MW renewable energy of REZ Group 8 and 600 MW off-shore wind generation.

Detailed existing Transmission System Expansion descriptions (including single line diagrams and summary tables) for each group with each transmission upgrade option are listed in the Appendix.

5.4.2. Transmission Network Expansion - 138 kV transmission line upgrade

Using Transmission Network Expansion Option 1 as an example to demonstrate two types of transmission line upgrades considered: 1) building a new 138 kV transmission line and 2) re-conductoring an existing 138 kV transmission line. In this Transmission Network Expansion option, a new 138 kV transmission line between Kahe and Wahiawa substations is built in order to facilitate the export of renewable energy from the Wahiawa substation.

To facilitate interconnecting all 1,160 MW of Group 8 to the Wahiawa substation, according to the power flow study for dispatch 7b through dispatch 7f listed in Table 5-1, additional line re-conductor and new lines are required among Kahe, Wahiawa, and Waiau substations to expand transmission corridor among the three substations. The detailed upgrade requirements for these transmission lines are listed in Table 5-3.

Table 5-3 Summary of 138 kV Transmission Line Upgrade Requirements for transmission upgrade option 1

No.	Transmission Line	Upgrade Type	Conductor Requirements
1	Kahe-Wahiawa	New Line, 138 kV	Three new circuits, with 1950 AAC conductor
2	Wahiawa-Waiau	Re-conductor	One circuit, re-conductor to double-bundled 795 AAC
3	Wahiawa-Waiau	New Line, 138 kV	Two circuits, with double-bundled 795 AAC
4	Makalapa-Waiau #1	Re-conductor	One circuit, re-conductor to double-bundled 795 AAC

5.4.3. Transmission Network Expansion - 138 kV substation expansion

Besides transmission line upgrade, existing substation expansion is also necessary in order to host the interconnection of the REZ and the new transmission lines. Using the Wahiawa substation as an example, the necessary substation expansion is described in Figure 9 in red. The substation is required to be expanded from 1 BAAH bay with 2 138 kV line connections to 6 BAAH bays with 11 138 kV line connections.

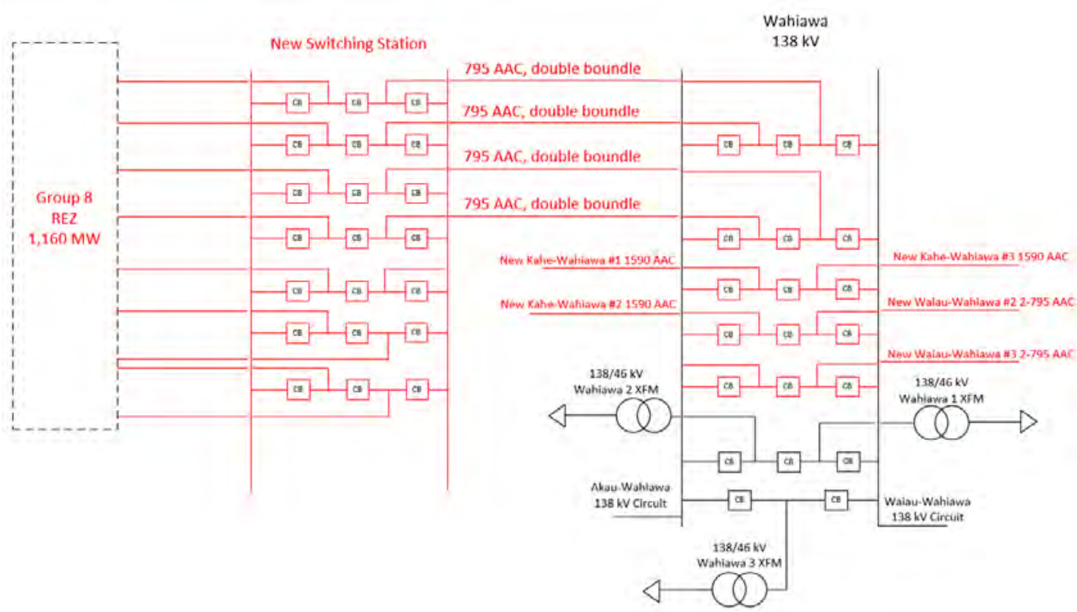


Figure 9 Wahiawa substation expansion requirements under the transmission upgrade option 1

5.4.4. Transmission Network Expansion - 345 kV Kahe-Wahiawa-Waiau loop

Considering the export of 1,160 MW renewable energy from the Wahiawa substation, and potential 600 MW off-shore wind, a very different Transmission Network Expansion – a 345 kV Kahe-Wahiawa-Waiau loop is considered in this study. Simplified single line diagram of the new 345 kV loop is shown as Figure 10.

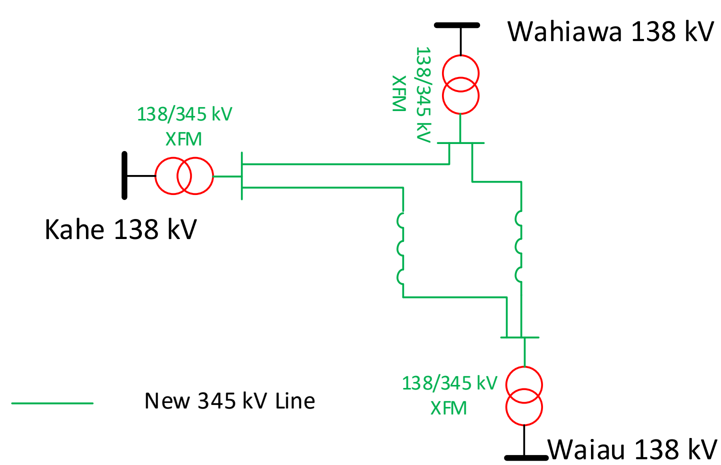


Figure 10 Simplified single line diagram for the new 345 kV Kahe-Wahiawa-Waiau loop

According to the power flow study, the new 345 kV loop can eliminate all 138 kV transmission line upgrade identified in the Transmission Network Expansion Option 1 and 2 for interconnecting the REZ groups 1-8, and only REZ Enablements are required. The minimum loading requirements for the 345 kV loop capacity related components are summarized in Table 5-4. It is worth noting that contingency of N-2 or loss one of 138/345 kV transformer contingency on the 345 kV loop is not considered in the study for the Transmission Network Expansion Option 3. Also, only capacity related equipment is identified in this study.

Although this study evaluates the performance of this option based on power flow simulations, in reality, a 345 kV system is an unchartered territory for Company; not only in terms of 345 kV equipment/device/apparatus, but also 345 kV related engineering/planning/system operation standards, and associated training should be considered as part of cost to have the 345 kV system. Note that 345 kV infrastructure generally requires larger (wider and/or taller) infrastructure as compared to 138 kV, which community, land, permitting, etc. would also need to be evaluated should this option be pursued further. The aforementioned considerations are not a comprehensive list, and were not evaluated in the scope of this study.

Table 5-4 Summary of 345 kV Loop Upgrade Requirements for Transmission Upgrade Option 3

Transmission Equipment	Requirements Description
138/345 kV Transformer	At Kahe substation, 1 unit, minimum continuous rating - 450 MVA, minimum emergency rating – 600 MVA
138/345 kV Transformer	At Wahiawa substation, 1 unit, minimum continuous rating - 450 MVA, minimum emergency rating – 600 MVA
138/345 kV Transformer	At Waiau substation, 1 unit, minimum continuous rating - 600 MVA, minimum emergency rating – 700 MVA
345 kV Transmission Line	Kahe-Wahiawa, double-bundled, 795 AAC
345 kV Transmission Line	Kahe-Waiau, double-bundled, 795 AAC
345 kV Transmission Line	Converting existing 138 kV circuit Wahiawa-Waiau to 345 kV and reconductor the circuit with double-bundled, 795 AAC
345 kV BAAH	2 bays for each substation (Kahe, Waiau and Wahiawa)

5.4.5. Transmission Network Expansion - Off-Shore Wind

600 MW off-shore wind

600 MW off-shore wind was evaluated as sensitivities for interconnection to either Kahe, Halawa, Iwilei, or Ko`olau 138 kV substations. In this sensitivity study scope, Transmission Network Expansions are identified in order to accommodate the 600 MW off-shore wind. The interconnection facilities between the off-shore wind resource to the interconnecting substation is not included in the study. Similar to what is identified for interconnecting REZ groups, to accommodate the offshore wind, new BAAH bays will be required at the hosting substation, and a Transmission Network Expansion will be required to mitigate overloading

identified through power flow study on the dispatch 8 to 13 listed in Table 5-2. Using Ko`olau substation as an example, Figure 11 demonstrates substation expansion requirements caused by both REZ Group 6 (in red) and the 600 MW off-shore wind interconnection (in blue) – two new BAAH bays are required for interconnecting 147 MW REZ Group 6 and four new BAAH bays with one new 138 kV line (Halawa-Ko`olau line with 1950 AAC conductor) are required for the interconnection of 600 MW off-shore wind. It is worth noting that Transmission Network Expansions identified in this study for interconnecting the off-shore wind depends on the sequence of interconnecting the offshore wind and the eight groups of REZ. The study assumes the off-shore wind will be interconnected to system after interconnecting eight groups of REZ.

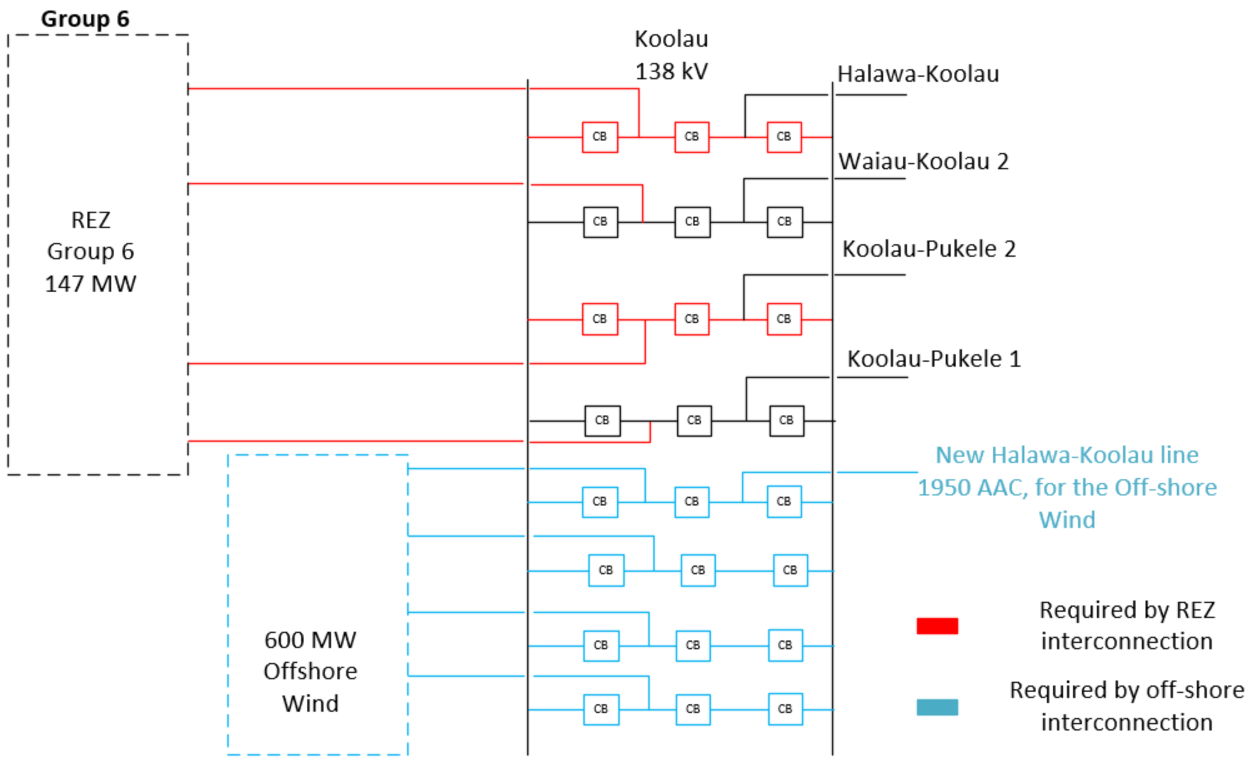


Figure 11 Ko`olau substation expansion requirements for interconnecting REZ Group 6 and 600 MW off-shore wind, Transmission Network Expansion option 1

During the study, it was concluded that Ho`ohana substation (hosting substation for REZ Group 1) expansion is required when interconnecting 600 MW off-shore wind resource to Kahe 138 kV substation, and Makalapa substation expansion is required when interconnecting off-shore wind at Halawa 138 kV substation. A feasibility analysis found that it is not feasible to expand either the Ho`ohana, Makalapa, or Iwilei substations. Therefore, the option of interconnecting the 600 MW offshore wind through the Kahe, Halawa, or Iwilei 138 kV substations (but not through 345 kV Kahe substation considered in the Transmission Network Expansion Option 3) were found to be infeasible.

400 MW off-shore wind

Based on stakeholder input provided in an October 6, 2021 meeting, additional analysis was performed to determine requirements for the interconnection of a 400 MW off-shore wind resource through Kahe (138 kV only), Halawa, Iwilei or Ko`olau substations. The same dispatch scenarios as what were analyzed for the 600 MW off-shore interconnection were analyzed. Transmission Network Expansion Options 1 and 2 were considered in this study. The analysis found the following:

- Kahe 138 kV substation interconnection is still not feasible due to the expansion requirement of the Ho`ohana substation.
- Halawa substation interconnection is still not feasible due to the expansion requirement of the Makalapa substation.
- Iwilei substation interconnection is not feasible due to space limitations.
- Ko`olau substation interconnection is feasible, and no additional Transmission Network Expansion is required in addition to the Transmission Network Expansion Option 1 or 2 (i.e., New Halawa-Koolau line is not required).

5.4.6. REZ Enablements

For REZ groups with lesser MW potentials, the REZ Enablements considered in the study scope is adding new BAAH bay(s) in the nearest, existing 138 kV substation. An example for this type of interconnection facility is shown in Figure 12 for Group 2. To interconnect 324 MW potential renewable of REZ Group 2, two new BAAH bays need to be added into Ewa Nui 138 kV substation, which is represented in color red in Figure 12.

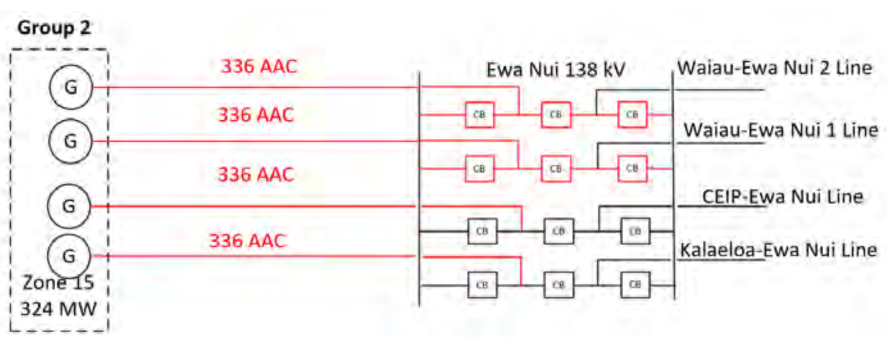


Figure 12 Single line diagram for interconnection REZ Group 2 (324 MW)

For REZ groups with higher MW potentials that exceed the capacity of existing substation, a new 138 kV switching station is required. Using REZ group 5 as an example, the single line diagram for the new switching station, as well as existing substation expansion is shown in Figure 13. With the support of the new switching station, limitations to sizes based on single point failure can be avoided.

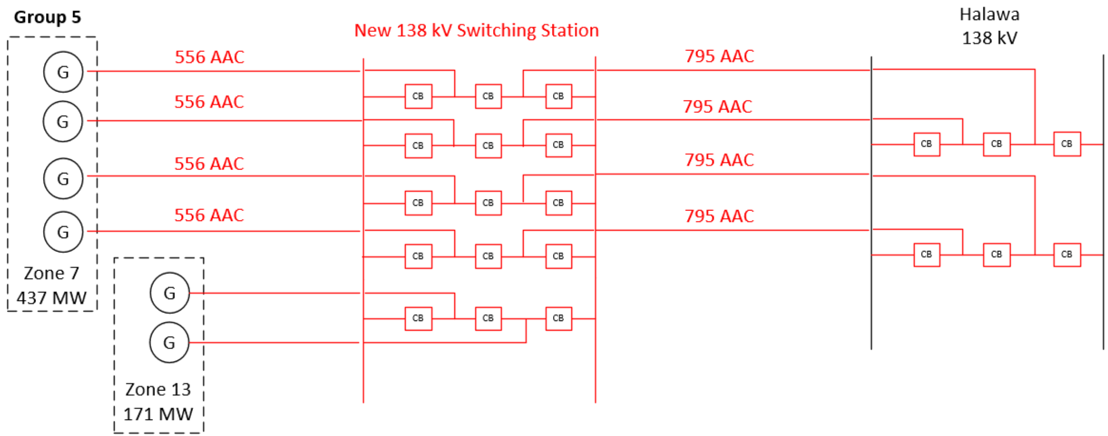


Figure 13 New 138 kV switching station and Halawa substation expansion (shown in red) for the interconnection of REZ Group 5

High-level single line diagrams for each REZ Group interconnection are shown in the Appendix. A high-level map of REZ Enablements required by REZ group are shown below in Figure 14.

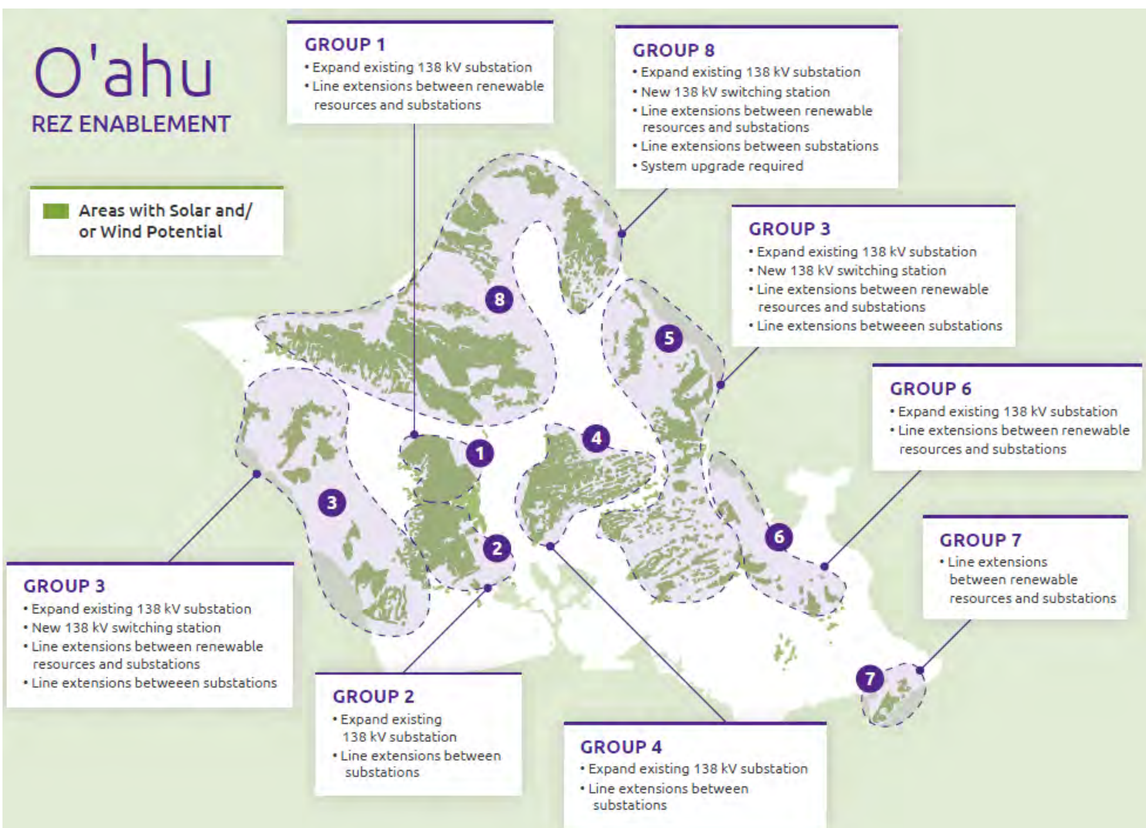


Figure 14: O`ahu REZ Enablement by Group

5.4.7. Summary of Total REZ Upgrades

A summary of the Total REZ Upgrades required to interconnect 3,344 MW REZ (total 8 groups) and 600 MW off-shore wind at three different substations are listed in this section. For each REZ group, the REZ Enablement requirements only depends on MW size and geographic location of the REZ group, and the interconnection substation current condition, and are independent among REZ groups.

The REZ Enablements required, which includes new switching stations, BAAH bays required in the new switching stations and existing substations, and new transmission line between new switching station and existing substations are summarized for the interconnection of each REZ group and the off-shore wind in Table 5-5 and Table 5-6. It is worth noting that REZ Group 7 is considered as a sub-transmission interconnection REZ, so no new transmission level interconnection facility for the interconnection of the REZ Group 7.

Table 5-5 Summary of Interconnection Facility Requirements for O`ahu REZ Interconnection

New Interconnection Infrastructure	Group 1 120 MW	Group 2 324 MW	Group 3 588 MW	Group 4 331 MW	Group 5 608 MW	Group 6 147 MW	Group 7 66 MW	Group 8 1,166 MW
New 138 kV Switching Station	0	0	1	0	1	0	0	1
No. of BAAH required in the new Switching Station	0	0	6	0	5	0	0	7
No. of new BAAH required in the existing Station	2	2	2	2	2	2	0	2
New 138 kV Transmission Lines	0	0	4	0	4	0	0	4
New 345 kV switching Station*	n/a	n/a	n/a	n/a	n/a	n/a	n/a	1
No. of BAAH required in the new 345 kV Switching Station*	n/a	n/a	n/a	n/a	n/a	n/a	n/a	6
New 345 kV Transmission Lines*	n/a	n/a	n/a	n/a	n/a	n/a	n/a	4

*Rows only for Transmission Upgrade Option 3 – new 345 kV loop.

Table 5-6 Summary of Interconnection Facility Requirements for O`ahu 600 MW Off-Shore Wind

Transmission Upgrade Option	Option 1	Option 2	Option 3	
New Interconnection Infrastructure	Off Shore Wind @ Ko`olau	Off Shore Wind @ Ko`olau	Off Shore Wind @ Kahe	Off Shore Wind @ Ko`olau
No. of new 138 kV BAAH required in the existing Station	4	4	0	4

New 138 kV Transmission Lines	0	0		0	0
No. of 345 kV BAAH	n/a	n/a	n/a	3	0

The Transmission Network Expansion includes new transmission lines (138 kV and 345 kV for Transmission Network Expansion option 3) and associated new BAAH in existing substations, 138 kV transmission line re-conductor, and new 345/138 kV transformer (only for Transmission Network Expansion option 3).

The summary of identified Transmission Network Expansion requirements are listed in Table 5-7. In this table, Transmission Network Expansion required for the off-shore wind is in addition to the Transmission Network Expansion identified for the REZ Group 8 interconnection. It is worth noting that the interconnection of REZ Group 1 to Group 7 do not require any existing transmission line upgrade according to the power flow study results. Hence, the Group 1 to the Group 7 are not listed in this table.

Table 5-7 Summary of Transmission Network Expansion for O`ahu REZ Interconnection

Transmission Upgrade Option	Transmission Upgrade	Group 8 (1,166 MW)	Off Shore Wind @ Kahe	Off Shore Wind @ Ko`olau
1	138 kV line re-conductor	2	n/a	2
	New 138 kV line	5		1
	New 138 kV BAAH	3		0
2	138 kV line re-conductor	3	n/a	2
	New 138 kV line	4		1
	New 138 kV BAAH	3		0
3	138 kV line re-conductor	0	n/a	2
	New 138 kV line	0		1
	New 138 kV BAAH	2		0
	New 345 kV Lines	3	0	n/a
	New 345 kV BAAH	6	0	
	New 345/138 kV XFM	3	0	

From studied dispatches with associated Total REZ Upgrade results, following conclusions can be made for initial O`ahu REZ study:

- Interconnection of REZ Group 1 to 7 requires less system upgrades, which means REZ Groups 1 to 7 are the "low hanging fruit" of REZ development. These groups do; however, require expansion of the transmission system to locations within the groups (REZ Enablements).
- To interconnect REZ Group 8 which is with the largest MW potential among all REZ groups, Wahiawa substation will be re-built, new transmission lines are required between Wahiawa, Kahe and Waiau substations, and large amount of REZ Enablement is required in order to interconnect REZ Group 8.
- The addition of 345 kV loop does not reduce the Transmission Network Expansion requirement for offshore wind interconnected at Koolau substation.

5.4.8. Total REZ Upgrade Cost Estimate

Cost estimate of aforementioned Total REZ Upgrade are summarized in following tables, which includes the estimate of the cost for REZ Enablements, and Transmission Network Expansion. The cost of hosting the 600 MW offshore wind is separated, which is additional cost on the Total REZ Upgrade for hosting eight REZ groups.

Table 5-8 Summary of Cost Estimate for REZ Enablement of O`ahu REZ

New Interconnection Infrastructure	Group 1 120 MW	Group 2 324 MW	Group 3 588 MW	Group 4 331 MW	Group 5 608 MW	Group 6 147 MW	Group 7 66 MW	Group 8 1,166 MW (138 kV)	Group 8 1,166 MW (345 kV)
REZ Enablement ($MM)	24.6	87.6	773.9	272.2	916.7	91.2	N/A	1460.7	1139.0
Cost ($MM) per MW	0.21	0.27	1.32	0.82	1.51	0.62	N/A	1.25	0.98

Based on IGP Stakeholder and TAP feedback, incremental REZ Enablement costs are provided for interconnecting grid-scale project with different levels of MW potential, with the assumption of fully realizing REZ MW potential. The increments within each group are based on 135 MW steps (Single Point of Failure for O`ahu) and are shown in Table 5-9 to Table 5-13. Estimates are prepared for REZ Group 2, 3, 4, 5, and 8 as these groups exceed the 135 MW increment. It is worth noting that these REZ Enablement cost estimate are indicative estimates and factors such as project size, relative location to existing transmission infrastructure, new transmission infrastructure build-out status, substation available space will impact actual REZ Enablement costs.

Table 5-9 Cost Estimate for REZ Enablement for O`ahu REZ Group 2 with incremental MW Potential

New Interconnection Infrastructure	Group 2 135 MW	Group 2 270 MW	Group 2 324 MW
REZ Enablement ($MM)	22.6	47.1	87.6
Cost ($MM) per MW	0.17	0.17	0.27

Table 5-10 Cost Estimate for REZ Enablement for O`ahu REZ Group 3 with incremental MW Potential

New Interconnection Infrastructure	Group 3 135 MW	Group 3 270 MW	Group 3 405 MW	Group 3 588 MW
REZ Enablement ($MM)	113.8	185.3	522.3	773.9
Cost ($MM) per MW	0.84	0.69	1.29	1.32

Table 5-11 Cost Estimate for REZ Enablement for O`ahu REZ Group 4 with incremental MW Potential

New Interconnection Infrastructure	Group 4 135 MW	Group 4 270 MW	Group 4 331 MW
REZ Enablement ($MM)	58.2	127.6	272.2
Cost ($MM) per MW	0.43	0.47	0.82

Table 5-12 Cost Estimate for REZ Enablement for O`ahu REZ Group 5 with incremental MW Potential

New Interconnection Infrastructure	Group 5 135 MW	Group 5 171 MW	Group 5 306 MW	Group 5 441 MW	Group 5 608 MW
REZ Enablement ($MM)	109.4	158.8	329.2	500.5	916.7
Cost ($MM) per MW	0.81	0.93	1.08	1.13	1.51

Table 5-13 Cost Estimate for REZ Enablement for O`ahu REZ Group 8 with incremental MW Potential

New Interconnection Infrastructure	Group 8 135 MW	Group 8 270 MW	Group 8 405 MW	Group 8 540 MW	Group 8 680 MW	Group 8 815 MW	Group 8 950 MW	Group 8 1,160 MW
REZ Enablement ($MM)	138.8	250.6	380.7	526.0	526.9	729.7	965.1	1460.7
Cost ($MM) per MW	1.03	0.93	0.94	0.97	0.77	0.90	1.02	1.26

Table 5-14 Summary of Cost Estimate for Transmission Network Expansion for O`ahu REZ Group 8 (greater than 300 MW)

	Transmission Network Expansion Option 1	Transmission Network Expansion Option 2	Transmission Network Expansion Option 3
Cost Estimate ($MM)	1,281.5	1,258.8	1,215.0

Table 5-15 Summary of Cost Estimate for 600 MW Offshore Wind Interconnection

Description	Off Shore Wind @ Ko`olau			Off Shore Wind @ Kahe 345 kV
Transmission Network Expansion Options	1	2	3	3

REZ Enablements Cost ($MM)	50.6	76.0
Transmission Network Expansion ($MM)	532.8	0
Total ($MM)	**583.5**	**76.0**

Table 5-16: Summary of Cost Estimate for 400 MW Offshore Wind Interconnection

Description	Off Shore Wind @ Ko`olau			Off Shore Wind @ Kahe 345 kV
Transmission Network Expansion Options	1	2	3	3
REZ Enablements Cost ($MM)	50.6			76.0
Transmission Network Expansion ($MM)	0			0
Total ($MM)	**50.6**			**76.0**

6. Maui Island Transmission REZs

6.1. REZ Groups

According to the NREL study results, Maui has 13,507 MW of grid-scale solar potential (PV-Alt-1, after removing the approved projects and in-study projects) and 767 MW wind potential (WIND-Alt-1). The total potential is 14,274 MW. Compared to O'ahu, Maui's total PV and wind potential is much higher than the forecasted 2040 peak load (287 MW). However, many areas with high levels of grid-scale solar MW potential or wind MW potential are far away from existing transmission infrastructure (e.g., south and east side of Maui island) and are not considered in this REZ study. During the later steps of the study, it is observed that the original 1.5 GW potential could cause significant 69 kV substation upgrades and expansions for many 69 kV substations, and many dispatch scenarios associated with the 1.5 GW potential causes significant high amount of MW loss on the system, as well as requiring more than usual amount of var resource across the island to maintain system voltage stability. An example of these extreme dispatches is that the whole island is power supplied by west Maui REZ. Therefore, the total MW potential of the transmission REZ is reduced for more realistic cost estimate at current stage of the study. Therefore, two REZ options with reduced potential MW are considered in the study for Maui island, which are shown in Figure 15 and Figure 16. REZ option 1 has 847 MW potential and REZ option 2 has 872 MW potential. The study assumes that all the REZ groups (except Group 4B1) will be interconnected to 69 kV transmission substations. List of substations considered in the study as REZ hosting substations are shown in Table 6-1.

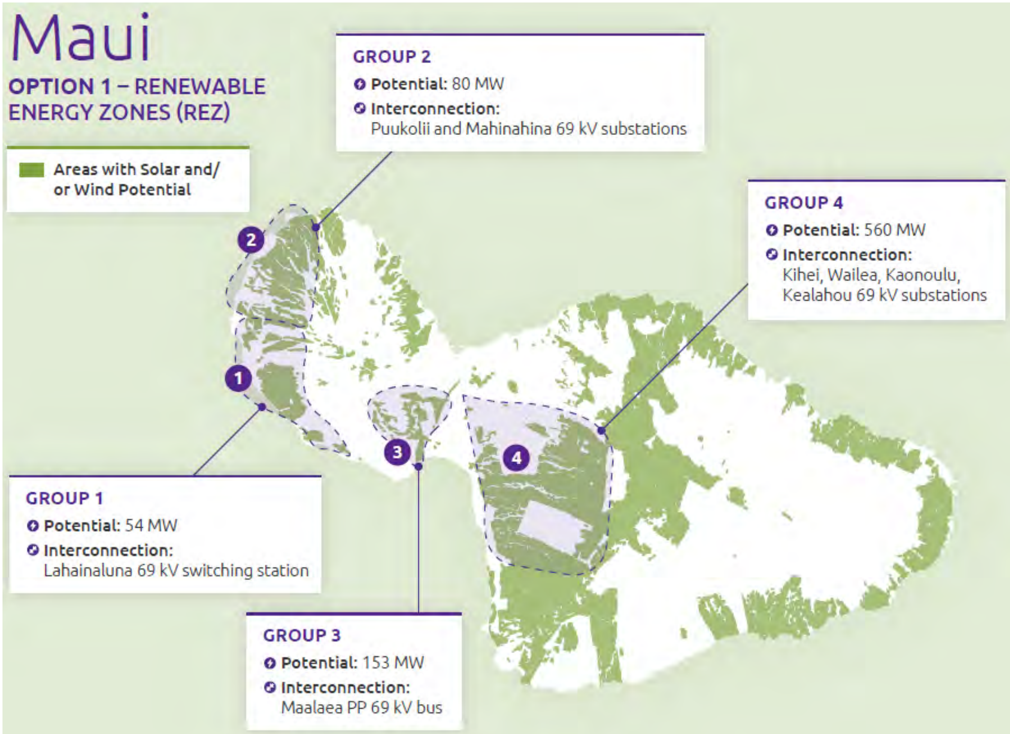


Figure 15 Maui island transmission REZ Option 1

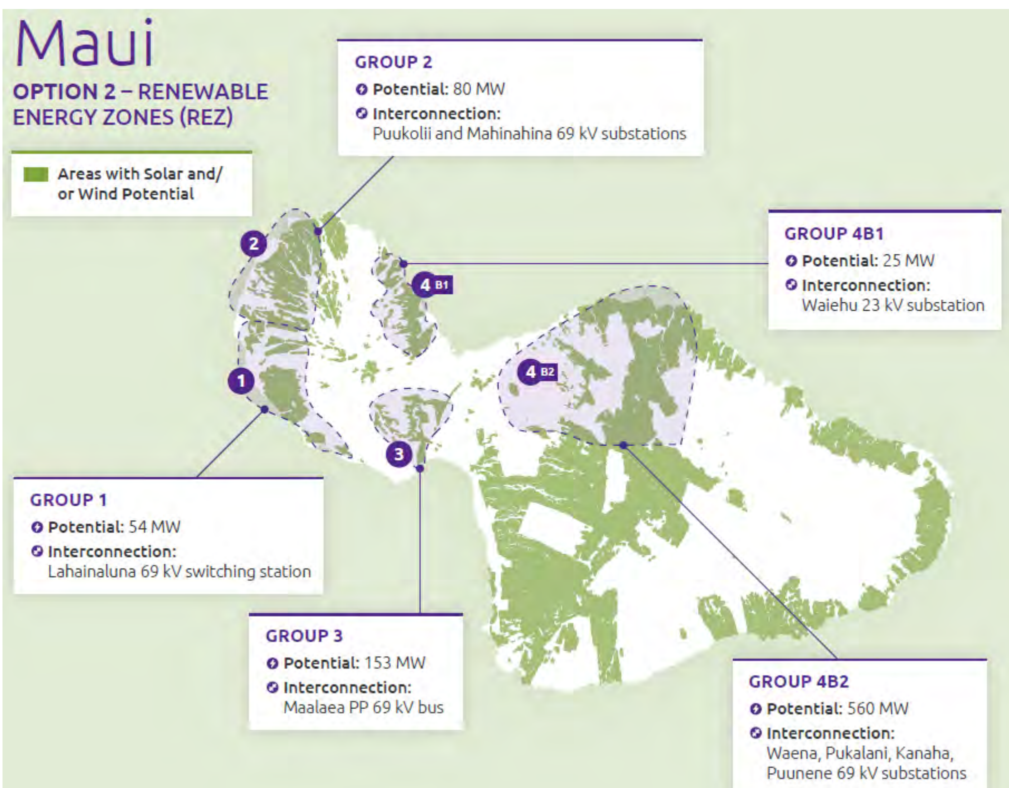


Figure 16 Maui island transmission REZ – Option 2

Table 6-1 69 kV Substations Considered for Maui Island REZ Interconnection Substation

REZ Group No.	REZ MW Potential	Interconnection Substation
1	54	Lahainaluna (69 kV)
2	80	Puukolii (69 kV), Mahinahina (69 kV)
3	153	Maalaea (69 kV)
4A	560	Kealahou (69 kV), Kihei (69 kV), Wailea (69 kV), Kaonoulu (69 kV)
4B1	25	Waiehu (23 kV)
4B2	560	Pukalani (69 kV), Puunene (69 kV), Kanaha (69 kV), Waena (69 kV)

6.2.Studied Generation Dispatches

Similar as what was identified for O`ahu REZ study, a group of dispatches of MW interconnection among all REZ groups listed in Table 6-1 are identified for the power flow study. The dispatches are designed to push MW generation of one or several REZ groups to the limit, and Maui island Transmission Network Expansion requirements are identified through performing power flow study for those dispatches. The studied dispatch for Maui island is shown in Table 6-2.

Table 6-2 Studied Generation Dispatches for Maui Island Transmission REZ

Dispatch #	Group 1 (54 MW)	Group 2 (80 MW)	Group 3 (153 MW)	Group 4A* (560 MW)	Group 4B1 (25 MW)	Group 4B2* (560 MW)	Existing Generation
1	0	0	Full	0	0	Full (Waena)	Dispatch if necessary
2	Full	Full	Full	0	0	0	Dispatch if necessary
3	0	0	Full	0	0	Full (Pukalani)	Dispatch if necessary
4	0	0	Full	Full (Wailea)	0	0	Dispatch if necessary
5	0	Full	Full	0	Full	Dispatch for remaining load (Pukalani)	Dispatch if necessary

*Four substations are selected to interconnect REZ in Group 4A and 4B2. "Full" means dispatching full generation of REZ from one substation.

6.3.Studied Transmission Network Expansion Options

Two transmission upgrade options are considered in the study:

- **Transmission Network Expansion Option 1** – Reconductor 69 kV and 23 kV transmission circuits and build new transmission circuit if necessary.
- **Transmission Network Expansion Option 2** – Convert existing Waiinu-Onehee-Kahului-Kanaha 23 kV line to 69 kV line, and reconductor and/or build new transmission circuit if necessary.

It is worth noting that the option 2 has been considered as part of Central Maui Transmission Upgrade in previous studies. The voltage conversion for the circuit is represented in Figure 17. This option includes both conductor voltage conversion, pole replacement, and Onehee substation and Kahului substation conversion to 69 kV substations.

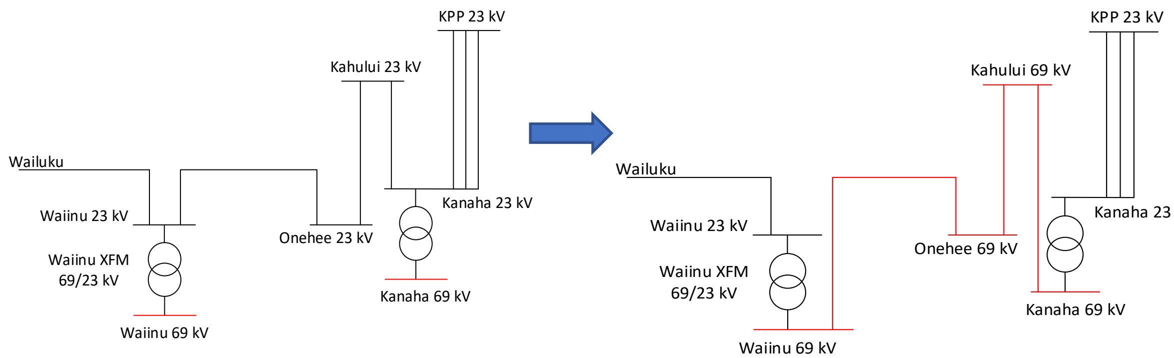


Figure 17 Single line diagram for Maui Transmission Upgrade Option 2

The Central Maui Transmission Upgrade project was evaluated as an alternative for the Waena switchyard and Kahului Power Plant (KPP) Synchronous condenser conversion projects to address system issues caused by the KPP retirement. During that evaluation, the Waena switchyard and KPP Synchronous condenser conversion projects were selected over the Central Maui Transmission Upgrade. Should option 2 be pursued in the future, the Waena switchyard and KPP synchronous condenser conversion projects will continue to effectively address system level issues and not become obsolete. Projects such as the Waena Switchyard and KPP SC projects were assumed to be in operation for purposes of this study, and additional mitigation (e.g., the Transmission Network Expansion Option 2) was found to be required to support Maui island load growth and REZ development.

6.4. Identifying Total REZ Upgrade Requirements

The Transmission Network Expansion scenarios provided above provide a baseline system for studies. This section describes the Total REZ Upgrades required, which represent 1) Transmission Network Expansions, which include the scenarios provided above as well as additional system upgrades required to mitigate criteria violations identified in accordance with the Hawaiian Electric transmission planning criteria and power flow study results, and 2) REZ Enablements, which are upgrades required to connect the center of each REZ to the nearest transmission substation. Examples of different types of transmission upgrades are listed in this section.

6.4.1. Transmission Network Expansions

Transmission Network Expansions are identified through a power flow study for system with both normal and contingency (N-1) configurations for all generation dispatches, which is shown in Table 6-2. It is worth noting that identified Transmission Network Expansion requirements on 69 kV side is very similar for both Transmission Network Expansion options.

The study is performed for both Transmission Network Expansion Option 1 and Option 2. Summary of required upgrades are listed in Table 6-3 for the Transmission Upgrade Option 1 and Table 6-4 for the Transmission Upgrade Option 2.

From studied dispatches with associated Transmission Network Expansion results, following conclusions can be made:

- Equipment overloading is triggered by both REZ interconnection and load growth. Primary reason of the overloading on 23 kV conductor and 69/23 kV tie transformers is load increase.
- Interconnection of REZ Group 1 and 2 does not cause equipment on West Maui side. This is because West Maui is a load center and there are three parallel circuits coming from Maalaea power plant 69 kV bus to West Maui which provides capacity there.
- Interconnection of REZ Group 3 on Maalaea power plant 69 kV bus does not cause any equipment overloading.
- Interconnection of REZ Group 4B1 on 23 kV circuit does not cause any equipment overloading.
- Interconnection of REZ 4A and REZ 4B2 causes significant 69 kV conductor overloading, which causes most part of South Maui and part of Central Maui 69 kV Transmission Network Expansion.
- Geographic balance should be considered as a constrain during REZ development.

Table 6-3 Transmission Network Expansion Required for Interconnecting Maui Island REZ Groups, Transmission Network Expansion Option 1

Dispatch No.	69 kV Tran. Line Reconductor	New 69 kV Tran. Line	23 kV Tran. Line Reconductor	New 23 kV Tran. Line	69/23 kV Tie XFM Upgrade (Cont./Emerg.) MVA
1	2 Circuits, with 556 AAC Waena-Kanaha, Maalaea-Kuihelani	n/a	n/a	2 Circuits, with 556 AAC Kahului-Kanaha, Kanaha-Puunene	Waiinu, 20/30 Kanaha, 22/50 Puunene, 22/45
2	7 Circuits, with 556 AAC Maalaea-Waena, Waena-Kanaha Maalaea-Kuihelani, Maalaea-Kihei, Puunene-Kuihelani, Wailea-Auwahi Wind, Auwahi Wind-Kealahou	1 Circuit, with 556 AAC Maalaea-Waena	n/a	2 Circuits, with 556 AAC Kahului-Kanaha, Kanaha-Puunene	Waiinu, 25/33 Kanaha, 20/40 Puunene, 20/38
3	9 Circuits, with 556 AAC Waena-Pukalani, Waena-Kanaha, Maalaea-Kuihelani, Maalaea-Kihei, Puunene-Kuihelani, Wailea-Auwahi Wind, Auwahi Wind-Kealahou, Kealahou-Kula, Kula-Pukalani	3 Circuits, with 556 AAC Kealahou-Kula Waena-Pukalani Kula-Pukalani	n/a	2 Circuits, with 556 AAC Kahului-Kanaha, Kanaha-Puunene	Waiinu, 20/30 Kanaha, 24/41 Puunene, 20/40
4	7 Circuits, with 556 AAC Wailea-Kihei, Kihei-Maalaea, Maalaea-Kuihelani, Wailea-Auwahi Wind,	4 Circuits, with 556 AAC Wailea-Kihei, Kihei-Maalaea, Wailea-Auwahi Wind,	n/a	2 Circuits, with 556 AAC Kahului-Kanaha, Kanaha-Puunene	Waiinu, 23/31 Kanaha, 22/40 Puunene, 22/37

	Auwahi Wind-Kealahou, Waena-Kanaha, Puunene-Kuihelani	Auwahi Wind- Kealahou			
5	2 Circuits, with 556 AAC Wailea-Auwahi Wind, Auwahi Wind-Kealahou	n/a	n/a	1 Circuit, with 556 AAC Kahului-Kanaha	Kanaha, 20/33 Puunene, 20/30

Table 6-4 Transmission Network Expansion Required for Interconnecting Maui Island REZ Groups, Transmission Network Expansion Option 2

Dispatch No.	69 kV Tran. Line Reconductor	New 69 kV Tran. Line	23 kV Tran. Line Reconductor	New 23 kV Tran. Line	69/23 kV Tie XFM Upgrade (Cont./Emerg.) MVA
1	1 Circuit, with 556 AAC Waena-Kanaha	n/a	n/a	n/a	n/a
2	7 Circuits, with 556 AAC Maalaea-Waena, Waena-Kanaha, Maalaea-Kuihelani, Maalaea-Kihei, Puunene-Kuihelani, Wailea-Auwahi Wind, Auwahi Wind-Kealahou	1 Circuit, with 556 AAC Maalaea-Waena	n/a	n/a	n/a
3	9 Circuits, with 556 AAC Waena-Pukalani, Waena-Kanaha, Maalaea-Kuihelani, Maalaea-Kihei, Puunene-Kuihelani, Wailea-Auwahi Wind, Auwahi Wind-Kealahou, Kealahou-Kula, Kula-Pukalani	3 Circuits, with 556 AAC Kealahou-Kula, Waena-Pukalani, Kula-Pukalani,	n/a	n/a	n/a
4	7 Circuits, with 556 AAC Wailea-Kihei, Kihei-Maalaea, Maalaea-Kuihelani, Wailea-Auwahi Wind, Auwahi Wind-Kealahou, Waena-Kanaha, Puunene-Kuihelani	4 Circuits, with 556 AAC Wailea-Kihei, Kihei-Maalaea, Wailea-Auwahi Wind, Auwahi Wind- Kealahou	n/a	n/a	n/a
5	2 Circuits, with 556 AAC Wailea-Auwahi Wind, Auwahi Wind-Kealahou	n/a	n/a	n/a	n/a

6.4.2. REZ Enablements

With the exception of Maalaea substation, which is designed as a power plant bus, many 69 kV transmission substations do not have BAAH topology. Therefore, in order to convert those load center substations to grid-scale renewable power plant interconnected substations, significant amounts of upgrades are required. Using Kihei 69 kV substation as an example. Current substation topology is shown in Figure 18. And Topology of Kihei substation with 140 MW interconnection capability is shown in Figure 19.

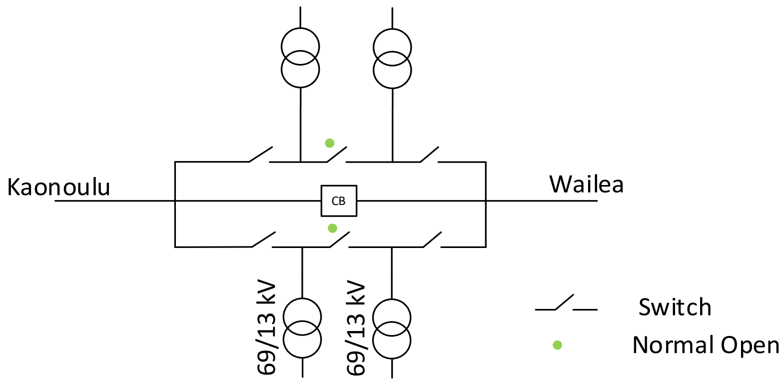


Figure 18 Current Kihei 69 kV substation topology

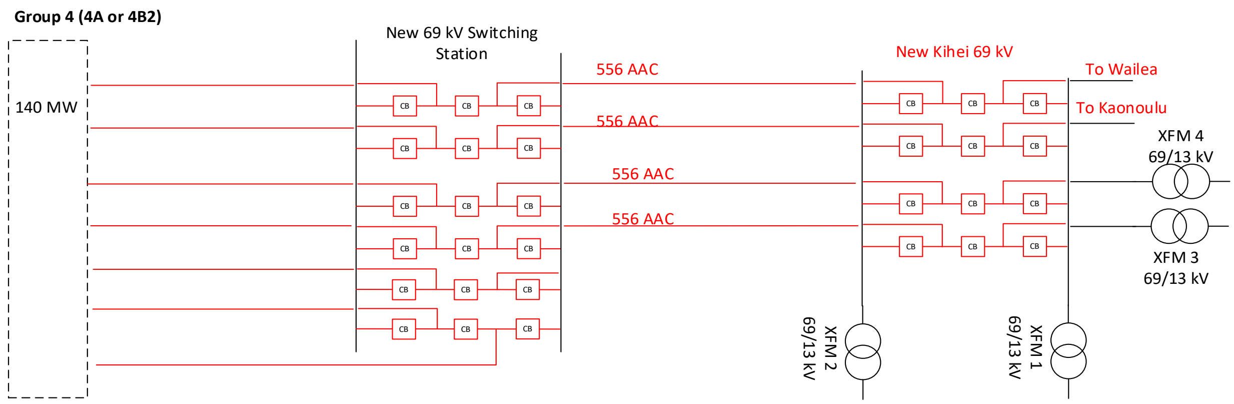


Figure 19 Topology of Kihei 69 kV substation with 140 MW interconnection capacity

A summary of interconnection facility requirements for interconnecting all REZ groups is listed in Table 6-5. Single line diagrams of these new transmission interconnection facilities are shown in the Appendix. A high-level map of REZ Enablements required by REZ group are shown below in Figure 20.

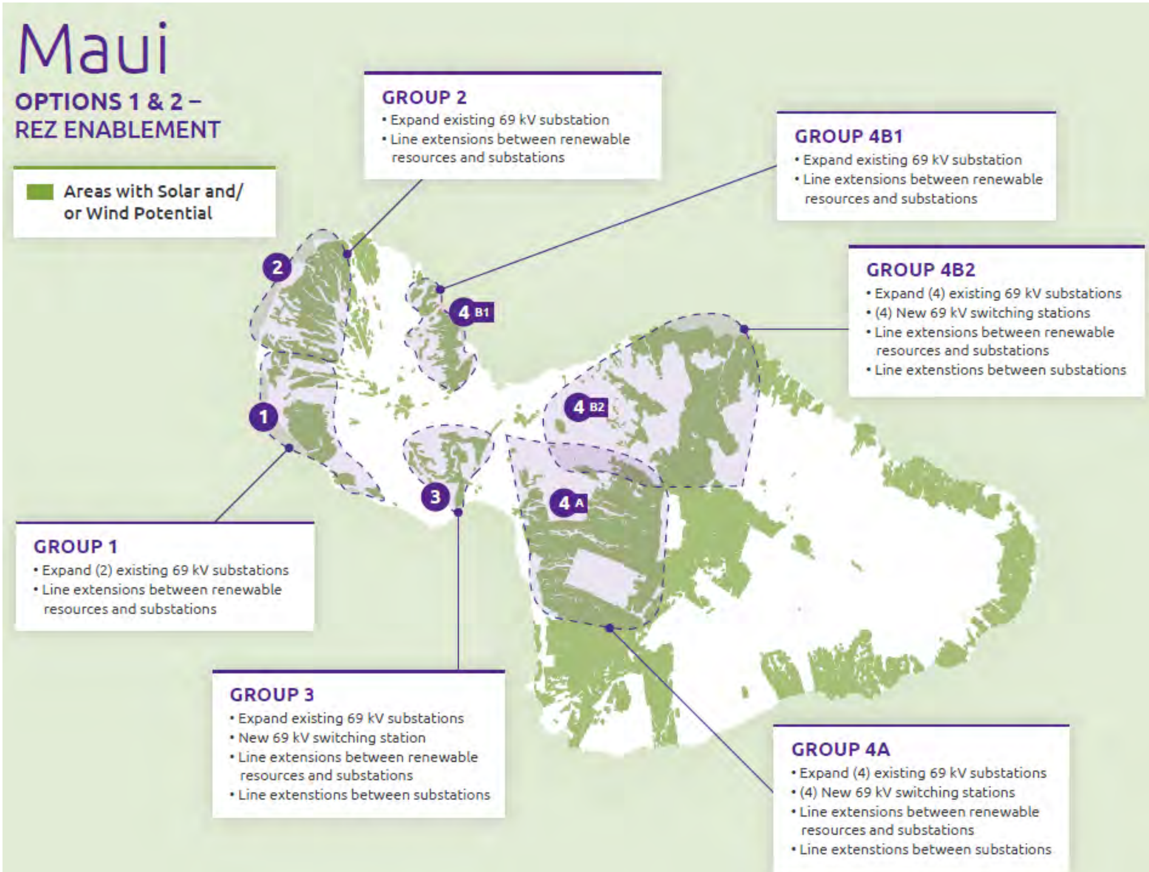


Figure 20: Maui Island REZ Enablement by Group

Table 6-5 New Transmission Infrastructure Required for Interconnecting Maui Island REZ Groups

REZ Group No.	REZ MW Potential	Interconnected Substation	No. of New Switching Station	No. of New BAAH Bay Required in Hosting Substation	New Transmission Line
1	54	Lahainaluna	0	4	0
2	40	Puukolii	0	2	0
	40	Mahinahina	0	2	0
3	153	Maalaea	1, with 6 bays of BAAH	4	4, with 556 AAC conductor
4A	140	Kealahou	1, with 6 bays of BAAH	4	4, with 556 AAC conductor
	140	Kihei	1, with 6 bays of BAAH	4	4, with 556 AAC conductor
	140	Wailea	1, with 6 bays of BAAH	4	4, with 556 AAC conductor
	140	Kaonoulu	1, with 6 bays of BAAH	4	4, with 556 AAC conductor
4B1	25	Waiehu	0	2	0
4B2	140	Waena	1, with 6 bays of BAAH	2	4, with 556 AAC conductor
	140	Kanaha	1, with 6 bays of BAAH	4	4, with 556 AAC conductor

	140	Puunene	1, with 6 bays of BAAH	4	4, with 556 AAC conductor
	140	Pukalani	1, with 6 bays of BAAH	4	4, with 556 AAC conductor

6.4.3. Total REZ Upgrade Cost Estimate

The cost of Total REZ Upgrade is estimated for interconnection facility for all REZ groups and system upgrade identified in the Transmission Network Expansion Option 1 and Option 2.

Table 6-6: Cost Estimate for REZ Enablements for Maui Island REZ

REZ Group	REZ Option 1				REZ Option 2				
	Group 1 54 MW	Group 2 80 MW	Group 3 153 MW	Group 4A 560 MW	Group 1 54 MW	Group 2 80 MW	Group 3 153 MW	Group 4B1 25 MW	Group 4B2 560 MW
REZ Enablement ($MM)	35.8	55.6	84.9	426.9	35.8	55.6	84.9	37.4	632.7
Transmission Network Expansion – Option 1 ($MM)	205.6				217.2				
Transmission Network Expansion – Option 2 ($MM)	186.0				194.2				
Total REZ Upgrade Cost Range ($MM)	789.2 – 808.8				1,040.6 – 1,063.6				
Total REZ Upgrade Cost Range ($MM) per MW	0.93 – 0.95				1.19 – 1.22				

Based on IGP Stakeholder and TAP feedback, incremental REZ Enablement costs are provided for interconnecting grid-scale project with different levels of MW potential. The increments within each group are broken down to 20 MW steps and are shown in Table 6-7 to Table 6-9. These estimates are prepared for groups with higher potentials (i.e. REZ Group 3, 4A and 4B2). It is worth noting that these cost estimates are indicative estimates and factors such as project size, relative location to existing transmission infrastructure, new transmission infrastructure build-out status, substation available space will impact actual REZ Enablement costs.

Table 6-7: Cost Estimate for REZ Enablement for Maui REZ Group 3 with incremental MW Potential

New Interconnection Infrastructure	Group 3 20 MW	Group 3 40 MW	Group 3 60 MW	Group 3 80 MW	Group 3 100 MW	Group 3 120 MW	Group 3 140 MW	Group 3 153 MW
REZ Enablement ($MM)	19.6	35.4	51.2	70.6	77.0	77.7	84.2	84.9
Cost ($MM) per MW	0.98	0.89	0.85	0.88	0.77	0.65	0.60	0.55

Table 6-8 Cost Estimate ($MM) for REZ Enablement for Maui REZ Group 4A with incremental MW Potential

Substation	Group 4A 20 MW/Sub	Group 4A 40 MW/Sub	Group 4A 60 MW/Sub	Group 4A 80 MW/Sub	Group 4A 100 MW/Sub	Group 4A 120 MW/Sub	Group 4A 140 MW/Sub

Kihei REZ Enablement ($MM)	58.7	75.2	92.0	112.0	118.5	119.2	125.7
Kihei Cost ($MM) per MW	2.94	1.88	1.53	1.40	1.19	0.99	0.90
Wailea Enablement ($MM)	54.3	66.0	77.7	90.0	96.4	97.1	103.6
Wailea Cost ($MM) per MW	2.72	1.65	1.30	1.13	0.96	0.81	0.74
Kaonoulu Enablement ($MM)	35.4	48.5	61.6	85.3	91.7	92.4	98.9
Kaonoulu Cost ($MM) per MW	1.77	1.21	1.03	1.07	0.92	0.77	0.71
Kealahou Enablement ($MM)	21.2	48.0	63.7	85.2	91.6	92.4	98.8
Kealahou Cost ($MM) per MW	1.06	1.20	1.06	1.07	0.92	0.77	0.71
Total Enablement ($MM)	**169.6**	**237.7**	**295**	**372.5**	**398.2**	**401.1**	**427**
Total Cost ($MM) per MW	**2.12**	**1.49**	**1.23**	**1.16**	**1.00**	**0.84**	**0.76**

Table 6-9 Cost Estimate ($MM) for REZ Enablement for Maui REZ Group 4B2 with incremental MW Potential

Substation	Group 4B2 20 MW/Sub	Group 4B2 40 MW/Sub	Group 4B2 60 MW/Sub	Group 4B2 80 MW/Sub	Group 4B2 100 MW/Sub	Group 4B2 120 MW/Sub	Group 4B2 140 MW/Sub
Waena Enablement ($MM)	32.8	54.2	85.1	110.0	116.4	117.2	123.6
Waena Cost ($MM) per MW	1.64	1.36	1.42	1.38	1.16	0.98	0.88
Kanaha Enablement ($MM)	76.4	96.3	127.9	159.5	165.9	166.7	173.1
Kanaha Cost ($MM) per MW	3.82	2.41	2.13	1.99	1.66	1.39	1.24
Puunene Enablement ($MM)	50.5	76.4	110.4	144.6	151.0	151.7	158.2
Puunene Cost ($MM) per MW	2.53	1.91	1.84	1.81	1.51	1.26	1.13
Pukalani Enablement ($MM)	61.6	90.5	119.2	164.2	170.6	171.3	177.8
Pukalani Cost ($MM) per MW	3.08	2.26	1.99	2.05	1.71	1.43	1.27
Total Enablement ($MM)	**221.3**	**317.4**	**442.6**	**578.3**	**603.9**	**606.9**	**632.7**
Total Cost ($MM) per MW	**2.77**	**1.98**	**1.84**	**1.81**	**1.51**	**1.26**	**1.13**

7. Hawaii Island Transmission REZs

7.1. REZ Groups

Similar to Maui island, Hawaiʻi island also has much larger renewable potential (around 76,000 MW) compared to the forecasted 2040 peak load (216 MW). However, many areas with high grid-scale solar MW potential or wind MW potential are far away from existing transmission infrastructure and are not considered in this REZ plan. Also, on Hawaiʻi island, there is a large amount of overlap between grid-scale PV potential zones and wind potential zones, and grid-scale PV potential MW is much larger than the wind potential; therefore, the grid-scale PV MW potential will be used for the study zones. However, the final renewable interconnection can consist of any renewable technology.

Considering balancing generation in different geographic locations of the island for resiliency, two different Transmission REZ options were developed on Hawaiʻi island, which are shown in Figure 21 and Figure 22.

In Option 1 (Figure 21), two REZs are planned on east and west side of Hawaiʻi island: Group 1 consists of 360 MW potential, and Group 2 consists of 360 MW potential. Total MW of interconnected REZ considered in the study is 720 MW.

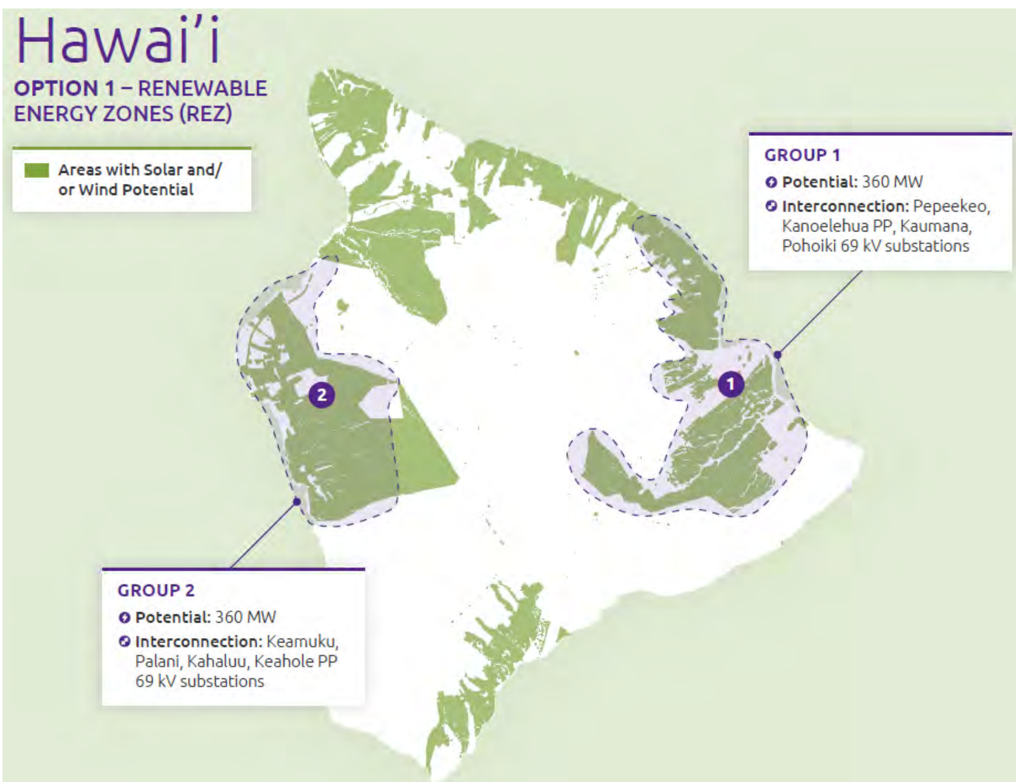


Figure 21 Hawai`i island transmission REZ Option 1

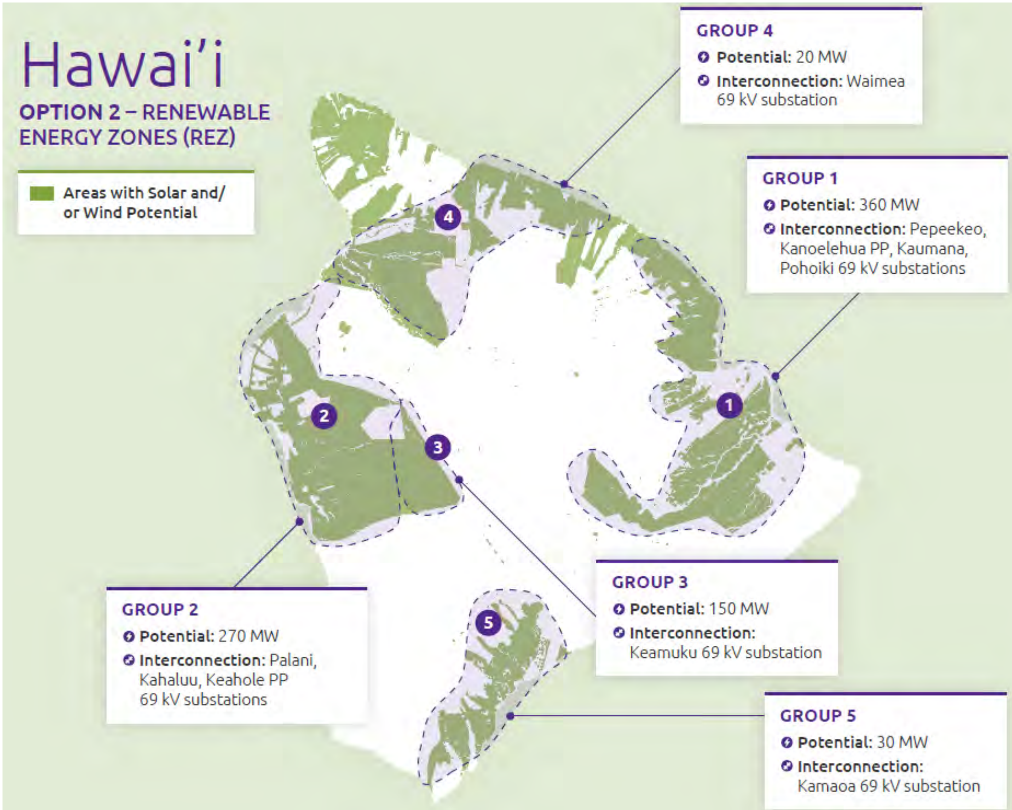


Figure 22 Hawai`i island transmission REZ Option 2

In Option 2 (Figure 22), five REZs are planned on east, west, north, south side and central of Hawai`i island: Group 1 consists of 360 MW potential, Group 2 consists of 270 MW potential, Group 3 consists of 150 MW, Group 4 consists of 20 MW, and Group 5 has 30 MW. The total MW of interconnected REZ considered in the study is 830 MW.

List of substations considered in the study as REZ hosting substations are shown in Table 7-1.

Table 7-1 69 kV Substations Considered for Hawai`i Island REZ Interconnection Substation

REZ Option	REZ Group No.	REZ MW Potential	Interconnection Substation
1	1	360	Pepeekeo, Kanoelehua PP, Kaumana, Pohoiki
	2	360	Keamuku, Palani, Kahaluu, Keahole PP
2	1	360	Pepeekeo, Kanoelehua PP, Kaumana, Pohoiki
	2	270	Palani, Kahaluu, Keahole PP
	3	150	Keamuku
	4	20	Waimea
	5	30	Kamaoa

7.2.Studied Generation Dispatch

Similar methodology as what was used for O`ahu and Maui island REZ study, a group of dispatches of renewable generation among all REZ groups identified for Hawai`i island are created for power flow study. The dispatches are designed to go through most, if not all, feasible combinations of REZ hosting substations with generation from REZ of all REZ groups in the power flow study, and identify Transmission Network Expansion requirements for those dispatches. The studied dispatch for Hawai`i island REZs is shown in Table 7-2 and Table 7-3.

Table 7-2 Studied Generation Dispatches for Hawai`i Island Transmission REZ Option 1

Scenario	Dispatch #	Group 1 (MW)				Group 2 (MW)				Existing Generation
		Pepeekeo	Kanoelehua PP	Kaumana	Pohoiki	Keamuku	Palani	Kahaluu	Keahole PP	
1	11	81	81	81	0	0	0	0	0	0
	12	82	82	0	82	0	0	0	0	0
	13	82	0	82	82	0	0	0	0	0
	14	0	83	83	83	0	0	0	0	0
	15	0	84	29	84	0	0	0	0	55
	16	0	30	84	84	0	0	0	0	55
2	21	0	0	0	0	76	76	76	0	0
	22	0	0	0	0	77	76	0	76	0
	23	0	0	0	0	77	0	76	76	0
	24	0	0	0	0	0	81	81	81	0
	25	0	0	0	0	78	0	0	21	131
	26	0	0	0	0	0	72	72	74	21

Table 7-3 Studied Generation Dispatches for Hawai`i Island Transmission REZ Option 2

Scenario	Dispatch #	Group 2 (MW)			Group 3 (MW)	Group 4 (MW)	Group 5 (MW)	Existing Generation
		Kahaluu	Palani	Keahole	Keamuku	Waimea	Kamaoa	
3	31	0	0	18	150	20	30	Dispatch if necessary
4	41	0	0	0	110	20	0	98
	42	0	0	32	105	20	0	71
5	51	75	0	0	100	0	30	21

7.3. Studied Transmission Network Expansion Options

Two transmission upgrade options are considered for Hawai`i island in this study:

- **Transmission Network Expansion Option 1** – Re-conductor existing 69 kV transmission line, and add new 69 kV transmission line if necessary
- **Transmission Network Expansion Option 2** – Conversion of existing L6200 cross island to a 138 kV cross island line, and re-conductor existing 69 kV transmission line/add new 69 kV transmission line if necessary

For the Transmission Network Expansion Option 2, a summary of existing 69 kV transmission infrastructure upgrades needed to convert the cross-island line from 69 kV to 138 kV is listed in Table 7-4. It is worth noting that possible protection system upgrades and/or transmission tower upgrades are not listed in the table.

Table 7-4 Summary of Transmission Infrastructure Upgrade Required for Converting L6200 to 138 kV

Transmission Equipment	Requirements Description
69/138 kV Transformer	Two units, with 171 MVA continuous rating and 196 MVA emergency
12.47/138 kV Transformer	One unit, with 6.25 MVA continuous rating, at Waikii substation
12.47/138 kV Transformer	One unit, with 2.5 MVA continuous rating, at Pohakuloa substation

7.4. Identifying Transmission Network Expansion Requirements

The Transmission Network Expansion scenarios provided above provide a baseline system for studies. This section describes the Total REZ Upgrades required, which represent 1) Transmission Network Expansions, which include the scenarios provided above as well as additional system upgrades required to mitigate criteria violations identified in accordance with the Hawaiian Electric transmission planning criteria and power flow study results, and 2) REZ Enablements, which are upgrades required to connect the center of each REZ to the nearest transmission substation. Examples of different types of transmission upgrades are listed in this section.

7.4.1. Transmission Network Expansions

According to the power flow study results, several 69 kV transmission lines are identified with overloading condition. Mitigation requirements are identified and listed in Table 7-5 which represents Transmission Network Expansion requirements with both studied Transmission Network Expansion Option 1 and 2.

A few observations can be obtained from the comparison of mitigation requirements for Transmission Network Expansion Option 1 and Option 2:

- Upgrading L6200 to 138 kV has very limited effect on alleviating local line overloading on east and/or west side caused by the more than usual amount of generation exporting from REZ groups.
- Supplying the whole island from only one side of generation can cause significant overloading and require large amount of line re-conductoring. This type of generation dispatch should be avoided. And REZ development needs to take generation location balance around the island into consideration.
- REZ Group 3, 4 and 5 appear to be “low-hanging fruit” type of groups. The interconnection of these REZ groups only causes limited Transmission Network Expansion requirements.

Table 7-5 69 kV Transmission Line Re-Conductor Requirements

Scenario No.	Transmission Line Section	Line No.	Transmission Network Expansion Option 1	Transmission Network Expansion Option 2 (138 kV L6200)
			Re Conductor Requirements	Re Conductor Requirements
1	Kaumana-Keamuku	L6200	556 AAC	556 AAC
	Keamuku-Waikoloa Solar-Waikoloa Load Tap	L8100	556 AAC	556 AAC
	Kanoelehua-Komohana	L6100	2-556 AAC	2-556 AAC
	Kanoelehua-Puna	L6400	2-556 AAC	2-556 AAC
	Kaumana-Kawailani-Paradise Park-Kapoho-Pohoiki	L6500	2-556 AAC	2-556 AAC
	Puna-Ainaloa-Pohoiki	L8700	2-556 AAC	2-556 AAC
2	Kaumana-Keamuku	L6200	556 AAC	556 AAC
	Kealia-Captain Cook-Keauhou-Kahaluu	L8600	336 AAC	336 AAC
	South Point-Punaluu	L6600	336 AAC	336 AAC
	Keahole-Huehue-Puuwaawa-Puuhulu	L6800	2-556 AAC	2-556 AAC
	Poopoomino-Anaehoomalu	L7100	2-556 AAC	2-556 AAC
	Keahole-Poopoomino	L9100	2-556 AAC	2-556 AAC
	Waiko-Keamuku	L8100	None	556 AAC
3	South Point-Punaluu	L6600	195.7 AAAC	3/0 AAAC
4	Kaumana-Keamuku	L6200	556 AAC	556 AAC
5	Kealia-Captain Cook-Keauhou-Kahaluu	L8600	336 AAC	336 AAC
	Kealia-Kapua-Kamaoa	L9600	556 AAC	556 AAC
	South Point-Punaluu	L6600	336 AAC	336 AAC
	Kilauea-Kulani-Panaewa	L6300	336 AAC	336 AAC

7.4.2. REZ Enablements

According to the Hawai`i island transmission planning criteria, the single point of failure limit is 30 MW, which means for most of REZ hosting substations required to host 90 MW will need 3 BAAH open positions from 3 different BAAH bays for the REZ interconnection. For the Keamuku substation, since the potential generation for the associated REZ is 150 MW, it will need 5 BAAH open positions from 5 different BAAH bays for the REZ interconnection in the REZ option 2.

Similar to Maui island, for 69 kV substations that do not have BAAH topology, BAAH topology will be required in order to interconnection REZ. For example, Kaumana 69 kV substation current topology is shown in Figure 23 and the rebuilt substation topology is shown in Figure 24.

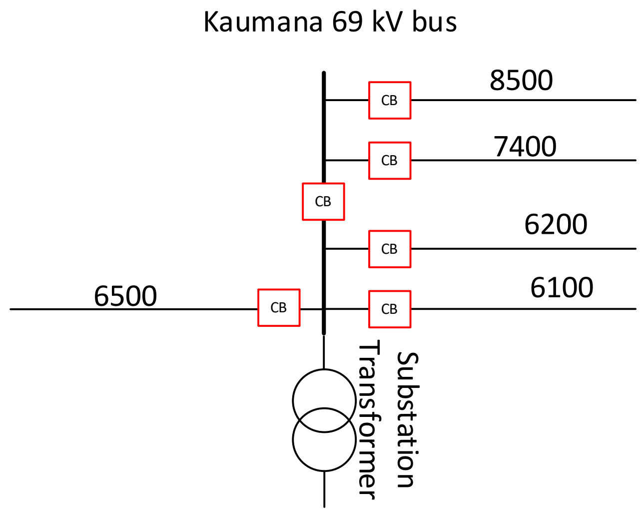


Figure 23 Kaumana 69 kV substation topology

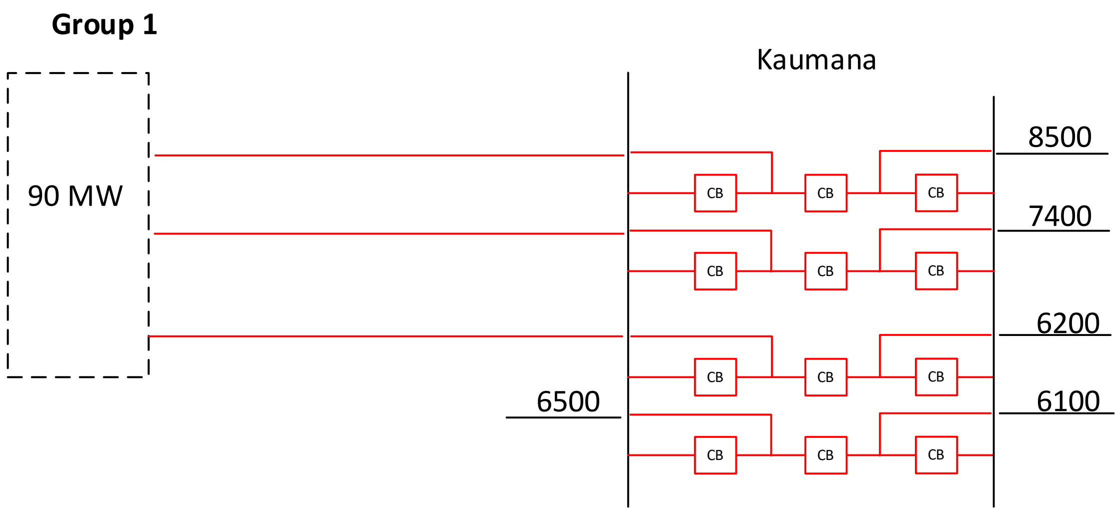


Figure 24 Kaumana 69 kV substation topology after rebuilding

Summary of REZ Enablements for interconnecting all REZ groups is listed in Table 7-6. Single line diagrams of these new transmission interconnection facilities are shown in the Appendix A. A high-level map of REZ Enablements required by REZ group are shown below in Figure 25.

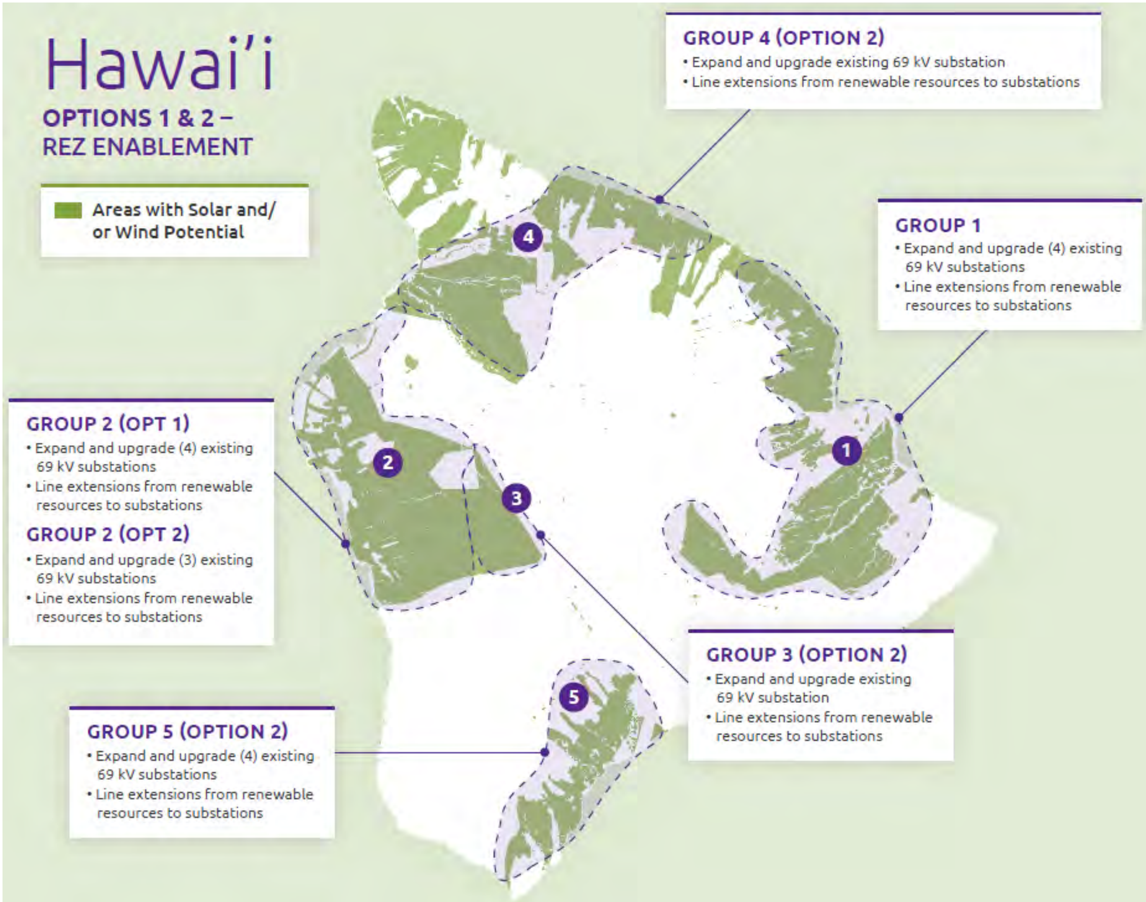


Figure 25: Hawaii Island REZ Enablement by Group

Table 7-6 Interconnection Facility Required for Interconnecting Hawai`i Island REZ Groups

REZ Group No.	REZ MW Potential	Interconnected Substation	No. of New Switching Station	No. of New BAAH Bay Required in Hosting Substation
1	90	Pepeekeo	0	3
	90	Kanoelehua PP	0	3
	90	Kaumana	0	4
	90	Pohoiki	0	3
2	90	Keamuku	0	4
	90	Palani	0	3
	90	Kahaluu	0	3
	90	Keahole PP	0	3
3	150	Keamuku	0	5
4	20	Waimea	0	2
5	30	Kamaoa	0	2

7.4.3. Total REZ Upgrade Cost Estimate

The cost of transmission infrastructure upgrade is estimated for interconnection facility for all REZ groups and system upgrades identified in the Transmission Network Expansion Options 1 and Option 2. For Transmission Network Expansion Option 2, the cost estimate to convert the existing L6200 line to a 138 kV line is $41 Million.

Table 7-7 Cost Estimate for REZ Enablements for Hawai`i Island REZ Groups – REZ Option 1

REZ Group #	Group 1				Group 2			
	Pepeekeo	Kanoelehua PP	Kaumana	Pohoiki	Keamuku	Palani	Kahaluu	Keahole PP
Potential MW	90	90	90	90	90	90	90	90
REZ Enablement Cost ($MM)	68.7	105.0	42.6	97.7	163.5	104.4	136.6	64.3
Cost ($MM) per MW	0.76	1.17	0.47	1.09	1.82	1.16	1.52	0.71

Based on IGP Stakeholder and TAP feedback, incremental REZ Enablement costs are provided for interconnecting grid-scale projects with different levels of MW potential. The increments within each group are broken down to 30 MW step size incremental and are shown in Table 7-8 for all substations listed in Table 7-7). It is worth noting that these cost estimates are indicative estimates and factors such as project size, relative location to existing transmission infrastructure, new transmission infrastructure build-out status, substation available space will impact actual REZ Enablement costs.

Table 7-8: Cost Estimate ($MM) for REZ Enablement for Hawai`i REZ Group 1 and 2 with incremental MW Potential in REZ Option 1

Substation	30 MW/Sub	60 MW/Sub	90 MW/Sub
Pepeekeo REZ Enablement ($MM)	33.8	48.6	68.7
Pepeekeo Cost ($MM) per MW	1.13	0.81	0.76
Kanoelehua PP REZ Enablement ($MM)	20.7	57.5	105.0
Kanoelehua Cost ($MM) per MW	0.69	0.96	1.17
Kaumana REZ Enablement ($MM)	41.2	41.9	42.6
Kaumana Cost ($MM) per MW	1.37	0.70	0.47
Pohoiki REZ Enablement ($MM)	32.5	74.5	97.7
Pohoiki Cost ($MM) per MW	1.08	1.24	1.09
Keamuku REZ Enablement ($MM)	79.2	121.2	163.5
Keamuku Cost ($MM) per MW	2.64	2.02	1.82
Palani REZ Enablement ($MM)	27.1	56.2	104.4

Palani Cost ($MM) per MW	0.90	0.94	1.16
Kahaluu REZ Enablement ($MM)	29.9	88.0	136.6
Kahaluu Cost ($MM) per MW	1.00	1.47	1.52
Keahole PP REZ Enablement ($MM)	25.5	51.1	64.3
Keahole PP Cost ($MM) per MW	0.85	0.85	0.71
Total REZ Enablement ($MM)	**240.6**	**505.8**	**782.9**
Total Cost ($MM) per MW	**1.00**	**1.05**	**1.09**

Table 7-9 Cost Estimate for REZ Enablements for Hawai`i Island REZ Groups – REZ Option 2

REZ Group #	Group 1				Group 2			Group 3	Group 4	Group 5
	Pepeekeo	Kanoelehua PP	Kaumana	Pohoiki	Palani	Kahaluu	Keahole PP	Keamuku	Waimea	Kamaoa
Potential MW	90	90	90	90	90	90	90	150	20	30
REZ Enablement Cost ($MM)	68.7	105.0	42.6	97.7	104.4	163.5	64.3	272.9	34.7	37.8
Cost ($MM) per MW	0.76	1.17	0.47	1.09	1.16	1.82	0.71	1.82	1.74	1.26

REZ Enablements cost estimates for transmission interconnection grid-scale project with 30 MW step size incremental are prepared as Table 7-10 for all substations considered in Hawai`i island REZ Option 2.

Table 7-10 Cost Estimate ($MM) for REZ Enablement for Hawai`i REZ Group 1, 2 and 3 with incremental MW Potential in REZ Option 2

Substation	30 MW/Sub	60 MW/Sub	90 MW/Sub	120 MW/Sub	150 MW/Sub
Pepeekeo REZ Enablement ($MM)	33.8	48.6	68.7	n/a	n/a
Pepeekeo Cost ($MM) per MW	1.13	0.81	0.76	n/a	n/a
Kanoelehua PP REZ Enablement ($MM)	20.7	57.5	105.0	n/a	n/a
Kanoelehua Cost ($MM) per MW	0.69	0.96	1.17	n/a	n/a
Kaumana REZ Enablement ($MM)	41.2	41.9	42.6	n/a	n/a
Kaumana Cost ($MM) per MW	1.37	0.70	0.47	n/a	n/a
Pohoiki REZ Enablement ($MM)	32.5	74.5	97.7	n/a	n/a
Pohoiki Cost ($MM) per MW	1.08	1.24	1.09	n/a	n/a
Palani REZ Enablement ($MM)	27.1	56.2	104.4	n/a	n/a

Palani Cost ($MM) per MW	0.90	0.94	1.16	n/a	n/a
Kahaluu REZ Enablement ($MM)	29.9	88.0	136.6	n/a	n/a
Kahaluu Cost ($MM) per MW	1.00	1.47	1.52	n/a	n/a
Keahole PP REZ Enablement ($MM)	25.5	51.1	64.3	n/a	n/a
Keahole PP Cost ($MM) per MW	0.85	0.85	0.71	n/a	n/a
Keamuku REZ Enablement ($MM)	79.2	121.2	163.5	208.5	272.9
Keamuku Cost ($MM) per MW	2.64	2.02	1.82	1.74	1.82
Kamaoa REZ Enablement ($MM)	37.8	n/a	n/a	n/a	n/a
Kamaoa Cost ($MM) per MW	1.26	n/a	n/a	n/a	n/a
Waimea REZ Enablement ($MM)	34.7[1]	n/a	n/a	n/a	n/a
Waimea Cost ($MM) per MW	1.16	n/a	n/a	n/a	n/a
Total MW	**290**	**530**	**770**	**800**	**830**
Total REZ Enablement ($MM)	**362.4**	**539.0**	**728.8**	**827.8[2]**	**892.2[2]**
Total Cost ($MM) per MW	**1.25**	**1.02**	**0.95**	**1.03**	**1.07**

1 - For 20 MW capacity only
2 - Includes cost for all substations (except Keamuku) with 90 MW or below interconnection size.

Table 7-11: Cost Estimate for Total REZ Upgrade for Hawai`i Island REZ Option 1 and 2

REZ Group	REZ Option 1		REZ Option 2				
	Group 1 360 MW	Group 2 360 MW	Group 1 360 MW	Group 2 270 MW	Group 3 150 MW	Group 4 20 MW	Group 5 30 MW
REZ Enablement ($MM)	314.0	468.9	314.0	305.3	272.9	34.7	37.8
Transmission Network Expansion – Option 1 ($MM)	369.6		408.3				
Transmission Network Expansion – Option 2 ($MM)	382.9		439.9				
Total REZ Upgrade Cost Range ($MM)	1,152.5 – 1,165.8		1,373.0 – 1,404.6				
Total REZ Upgrade Cost Range ($MM) per MW	1.60 – 1.62		1.65 – 1.69				

8. IGP TAP & Stakeholder Review

The Company provided a draft of this document on October 1, 2021 to IGP stakeholders for review. The Company also presented the study to the IGP Technical Advisory Panel (TAP) on October 1, 2021 and the IGP Stakeholder Technical Working Group (STWG) on October 6, 2021. The TAP's feedback is included in Appendix B and summarized with responses below. Feedback from various organizations within the IGP STWG are included in Appendix C with responses as appropriate.

8.1. Summary of TAP Feedback and Responses

Prior presenting to IGP STWG meeting, the study was presented to IGP Technical Advisory Panel for review on October 1, 2021. Overall, the TAP team recognized that the study established transmission limits that may impact amounts of renewable energy that can be interconnected beyond what is seen from the resource analysis. The IGP TAP provided guidance regarding next steps of the study. A summary of key feedback provided by the IGP TAP (complete version included in Appendix B), as well as Company's responses are listed below.

1. **TAP advised that the REZ planning process also would need consider environmental and community acceptance constraints.**

   Company Response: The Company agree with TAP's suggestion, and as planned, both environmental goal and community engagement are considered in the whole REZ planning process.
2. **TAP recommended that more sophisticated power flow study than a single point snapshot study should be performed in future steps. This includes:**
   a. **Considering both voltage and thermal study criteria in the study**
   b. **Considering a chronological tool with an underlying transmission topology rather than a single point snapshot analysis**
   c. **Non-transmission alternatives such as power flow control devices (phase shifters, in-line compensators, etc) or even energy storage elements for congestion management should be considered in the study.**
   d. **Use of dynamic line rating technology to manage flows in operational time frame can also be considered.**
   e. **Considering Behind-The-Meter DER in the study**

   Company Response: As mentioned before, the current study is just the starting point of the whole REZ planning process. It focuses on the initial feasibility exploration. It is expected that after receiving feedbacks from stakeholders, community and TAP team, more detailed study will be performed with more realistic assumptions for more detailed scope in next iterations.
3. **An evaluation of more MW integration levels is strongly recommended for O`ahu REZ Group 8, and recommended for the other groups as it may determine a different priority/cost for integration in each zone; for example, a stepwise $/MW curve for each**

group may be obtained. At the same time, the TAP recognized that this is an initial pass at transmission cost estimation that will be refined in future steps.

Company Response: The Company revised REZ Enablements cost with detailed estimate for stepwise MW incremental scenarios for REZ Groups with high MW potential. However, due to the limited time before November 1, 2021 filing, the Transmission Network Expansion cost for stepwise MW incremental scenarios is not performed. This will be considered in the future steps of the study.

4. **The study may need address system resilience requirements for scenarios such as extreme weather condition.**

   Company response: The system resilience requirement was not studied in the REZ study but may be needed as a future sensitivity as well as in separate studies. In developing severe weather scenarios, Company would also need to take into account the full suite of resilience-related solutions to manage the impact.

5. **The TAP agrees with the premise that it is preferable to provide planned interconnection points for renewables rather than piecemeal tapping of transmission lines as is currently being done.**

6. **The 345 kV would be a new transmission voltage level for HECO, which means a need for a whole new class of equipment, spare parts, etc.**
   Company response: Yes, and the associated cost, such as for equipment, right-of-way purchase, and personnel training, that is not directly related with the REZ development is not considered in the study. Therefore, the total cost of having a new 345 kV loop could be much more expensive than the preliminary estimate in the report.

9. Conclusions and Next Steps

Following conclusions are reached for Oahu REZ study:

- Interconnecting REZ groups 1 to 7 requires minimum Transmission Network Expansions, and is the "low hanging fruit" identified in the study. Further efforts need to be spent to determine if Stakeholders are interested to develop grid-scale renewable energy in those zones.
- Due to the existing design and condition of the Wahiawa 138 kV substation, significant efforts need to be spent to convert the Wahiawa substation from a non-load center common substation to a GW size generation switching station for the interconnection of 1,160 MW potential of the REZ group 8 (located at north of the Wahiawa substation).

- Due to substation limitations, 600MW of off-shore wind cannot be interconnected at Halawa, Kahe, or Iwilei substations, but can only interconnected at Ko`olau substation and 345 kV Kahe substation under Transmission Network Expansion Option 3 among all options evaluated in the study.
- Additional analysis was performed for 400 MW of off-shore wind interconnection, which also found Ko`olau substation as the only feasible interconnection point among the Kahe substation, Iwilei substation, Ko`olau substation and Halawa substation. The 400 MW of interconnection also found that no additional Transmission Network Expansion was identified beyond the Transmission Network Expansion identified to interconnect REZ groups 1 to 8.

Following conclusion are reached for Maui island REZ study:

- Maui island REZ development should consider generation plant geographic diversity around the island. REZ development should be planned in geographic balance way among west Maui, south Maui and central Maui.
- Interconnection of REZ Group 1, 2, 3 and 4B1 could require limited Transmission Network Expansion. These four groups of REZ are the “low hanging fruit” of REZ development identified from the study.
- Interconnection of REZ 4A and REZ 4B2 causes significant 69 kV conductor overloading, which requires most part of South Maui and part of Central Maui 69 kV Transmission Network Expansion.

Following conclusion are reached for Hawaii island REZ study:

- Similar to Maui island, REZ development should consider generation plant geographic diversity around the island. REZ development should be planned in geographic balance way among east and west cost of Hawai`i island.
- Upgrading L6200 to 138 kV has very limited effect on alleviating line overloading on east and west side caused by the more than usual amount of generation exporting from REZ groups.
- Supplying the island with generation primarily from one area can cause significant overloading and require large amount of line re-conductoring. This type of generation dispatch should be avoided. And REZ development need take into generation location balance around the island into consideration.
- REZ Group 3, 4 and 5 are the “low-hanging fruit” type group. The interconnection of these REZ groups could require limited Transmission Network Expansion.

10. Appendix A – O`ahu REZ and Off-Shore Wind Interconnection

10.1. Transmission Upgrade Requirements Identified with Transmission Network Expansion Option 1

Single line diagrams of hosting 138 kV substation with upgrades required for REZ and off-shore wind interconnection, with Transmission Network Expansion Option 1 (red represents required upgrade, and black represent existing system) are shown as following. It is worth noting that re-conductor type of upgrade is not shown in the following single line diagram.

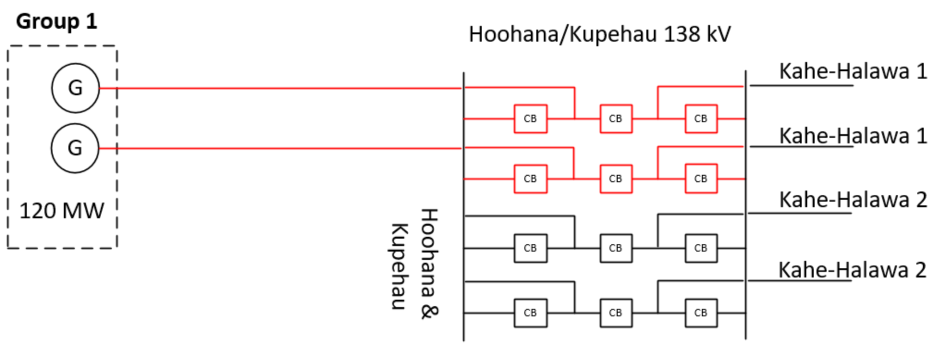


Figure 26 Ho`ohana substation upgrade required for hosting REZ Group 1, Transmission Network Expansion Option 1

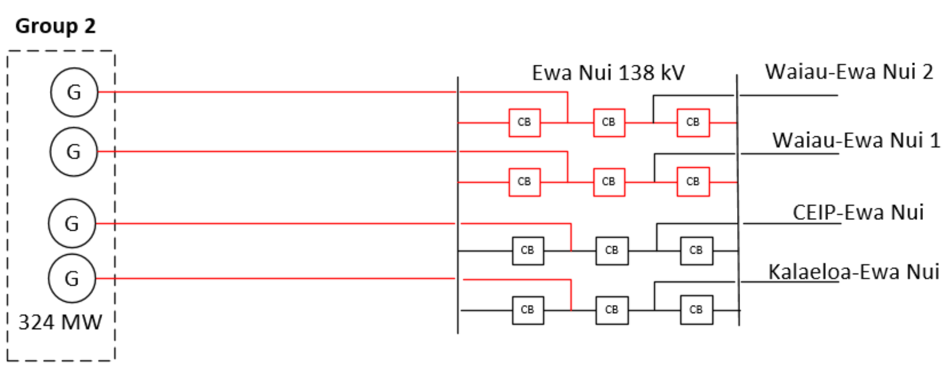


Figure 27 Ewa Nui substation upgrade required for hosting REZ Group 2, Transmission Network Expansion Option 1

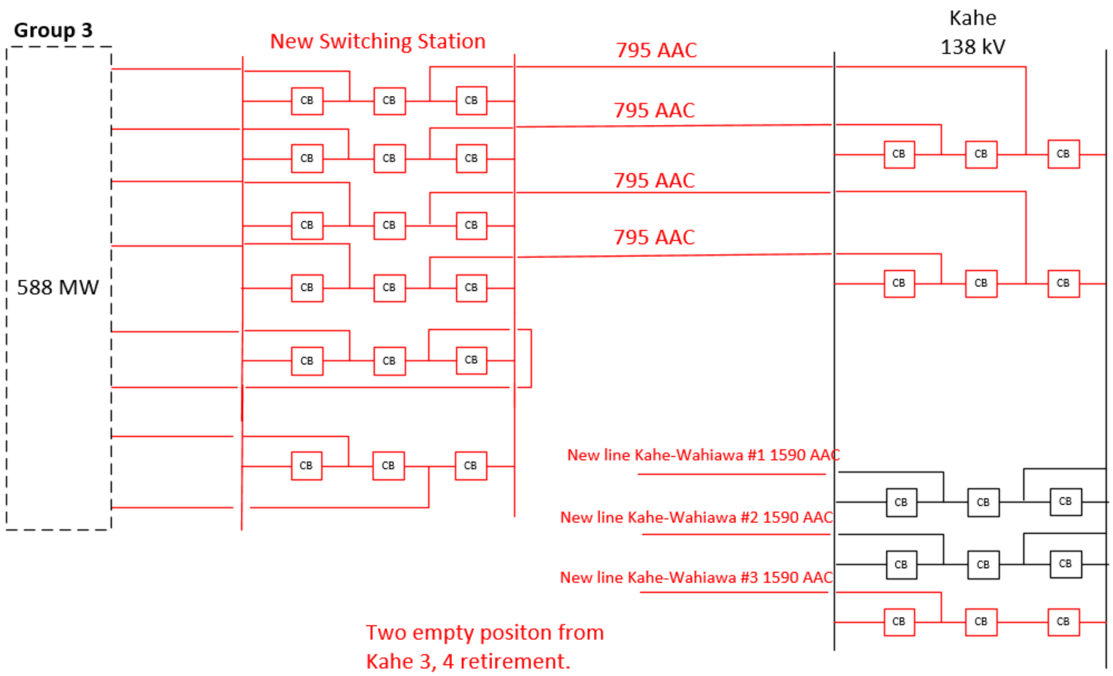


Figure 28 Kahe substation upgrade required for hosting REZ Group 3, Transmission Network Expansion Option 1

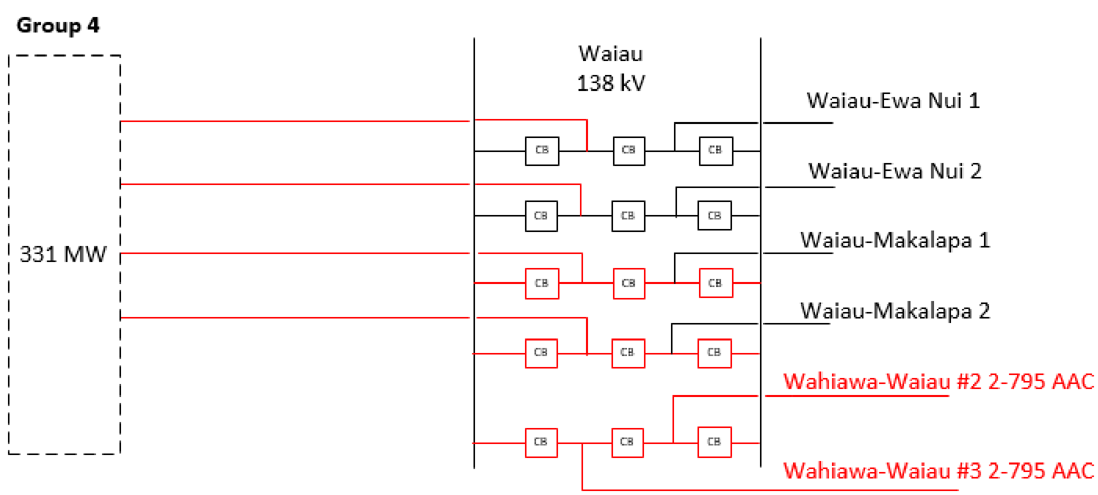


Figure 29 Waiau substation upgrade required for hosting REZ Group 4, Transmission Network Expansion Option 1

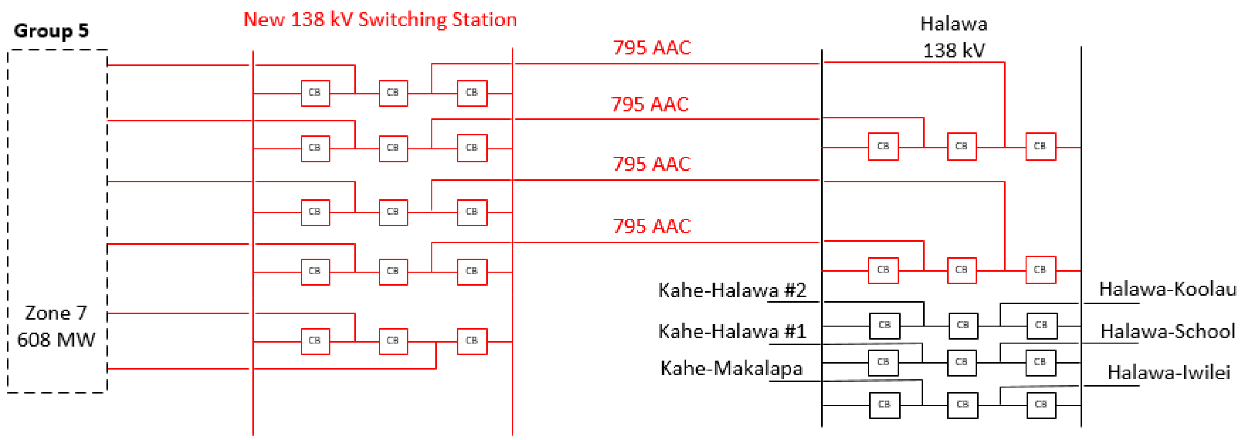


Figure 30 Halawa substation upgrade required for hosting REZ Group 5, Transmission Network Expansion Option 1

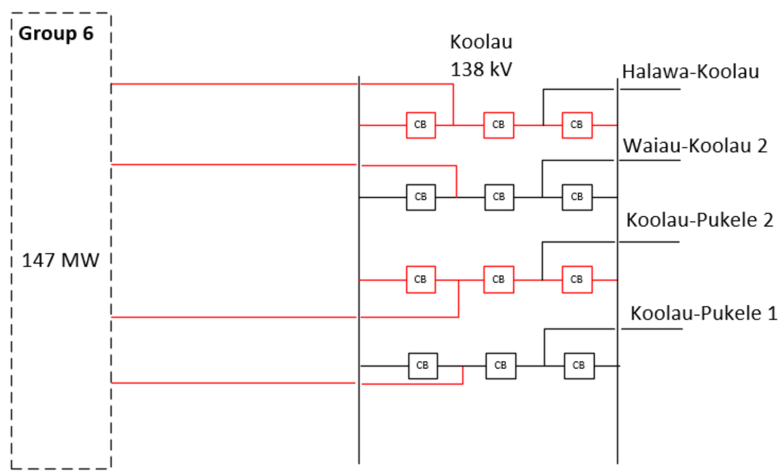


Figure 31 Ko`olau substation upgrade required for hosting REZ Group 6, Transmission Network Expansion Option 1

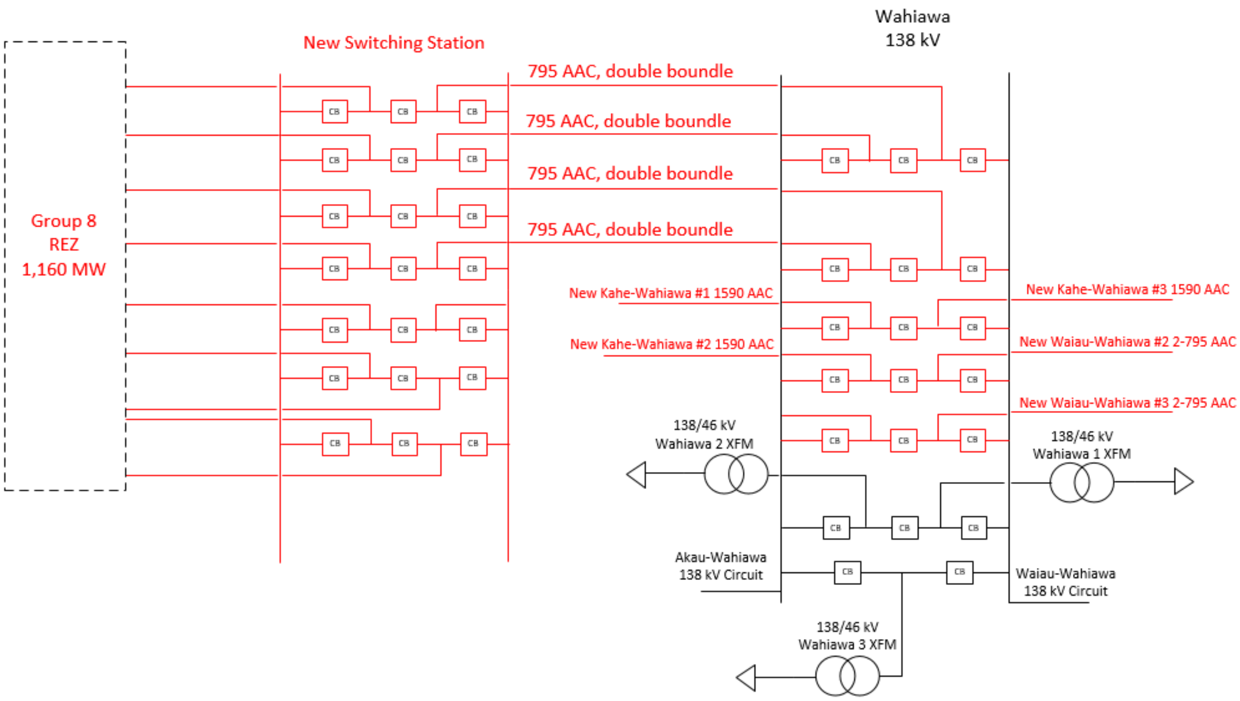


Figure 32 Wahiawa substation upgrade required for hosting REZ Group 8, Transmission Network Expansion Option 1

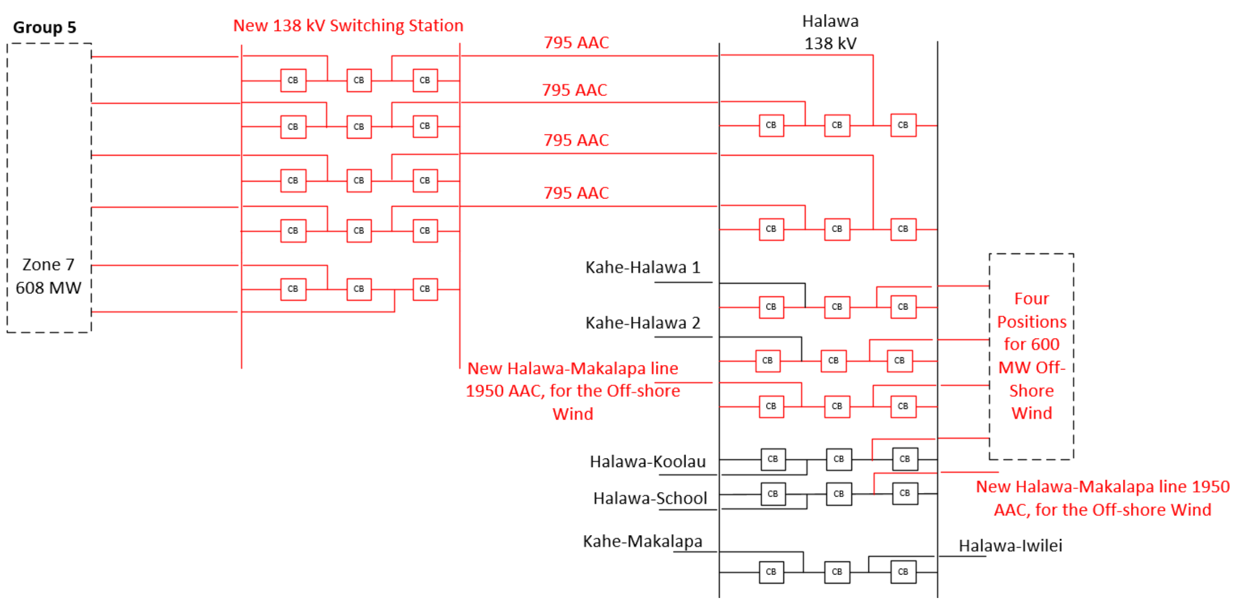


Figure 33 Halawa substation upgrade required for hosting REZ Group 7 and 600 MW off-shore wind, Transmission Network Expansion Option 1

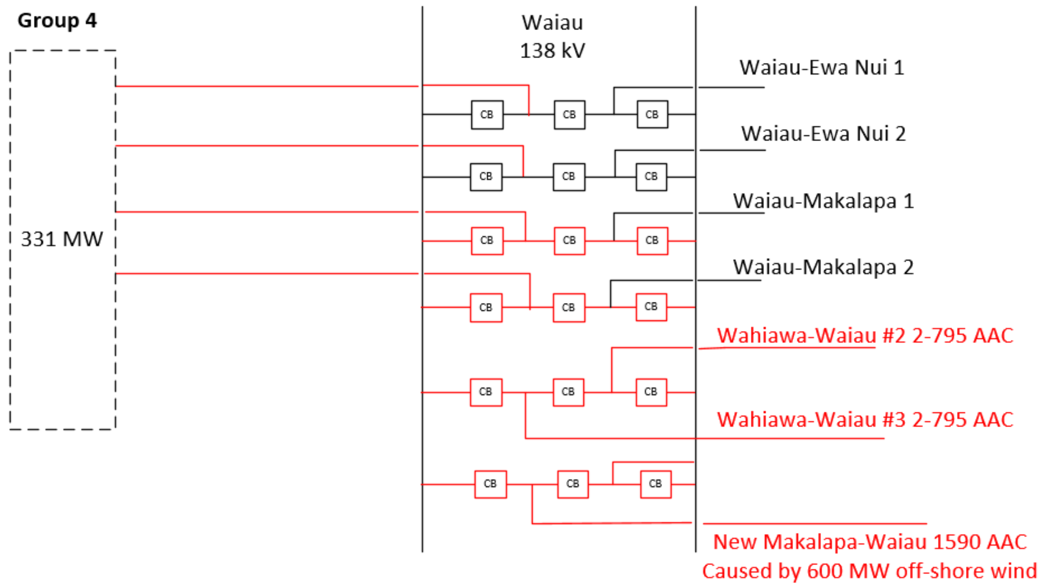


Figure 34 Waiau substation upgrade required for hosting REZ Group 4 and hosting 600 MW off-shore wind at Halawa substation, Transmission Network Expansion Option 1

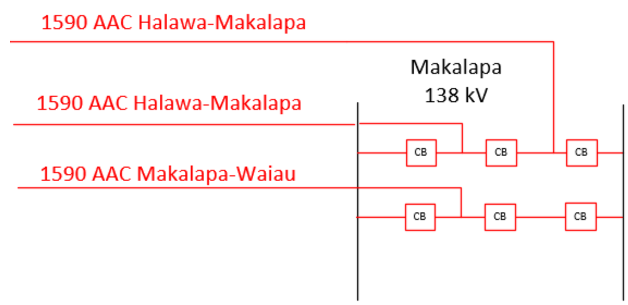


Figure 35 Makalapa substation upgrade required for hosting 600 MW off-shore wind at Halawa substation, Transmission Network Expansion Option 1 (existing part of the Makalapa substation is illustrated)

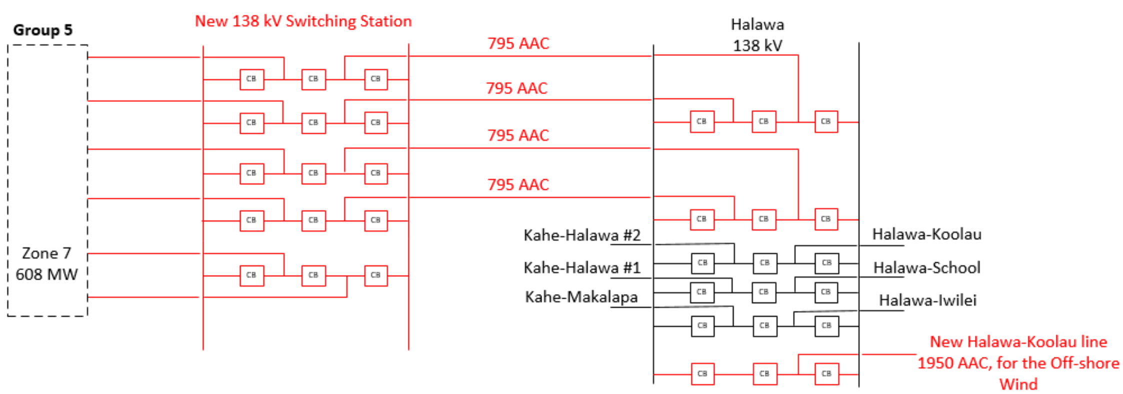


Figure 36 Halawa substation upgrade required for hosting REZ Group 5 and hosting 600 MW off-shore wind at Ko`olau substation, Transmission Network Expansion Option 1

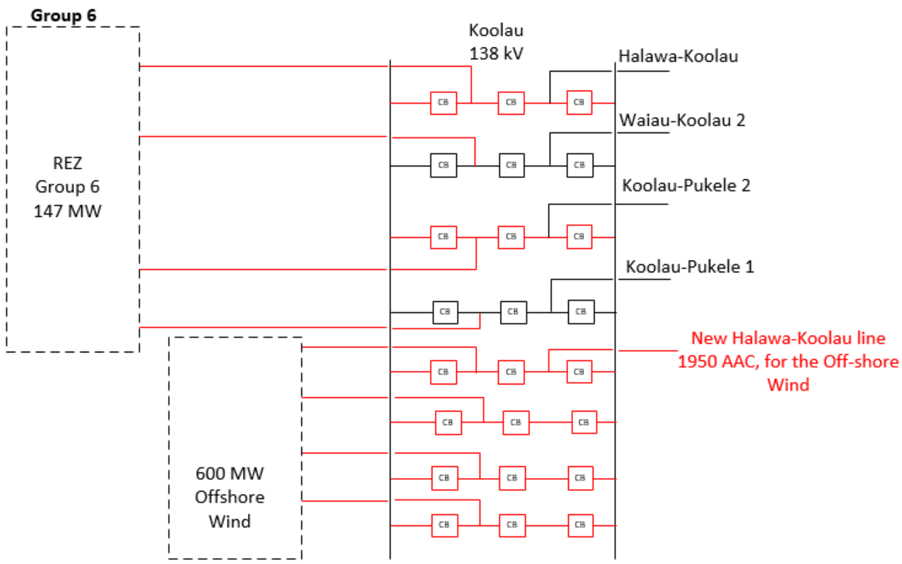


Figure 37 Halawa substation upgrade required for hosting REZ Group 5 and hosting 600 MW off-shore wind at Ko`olau substation, Transmission Network Expansion Option 1

Table 10-1 Summary of 138 kV Transmission Line Upgrade Requirements for hosting REZ 8 Groups with Transmission Network Expansion Option 1

No.	Transmission Line	Upgrade Type	Conductor Requirements
1	Kahe-Wahiawa	New Line, 138 kV	Three new circuits, with 1950 AAC conductor
2	Wahiawa-Waiau	Re-conductor	One circuit, re-conductor to double-bundled 795 AAC
3	Wahiawa-Waiau	New Line, 138 kV	Two circuits, with double-bundled 795 AAC
4	Makalapa-Waiau #1	Re-conductor	One circuit, re-conductor to double-bundled 795 AAC

Table 10-2 Summary of 138 kV Transmission Line Upgrade Requirements for hosting 600 MW Off-Shore Wind at Halawa Substation with Transmission Network Expansion Option 1

No.	Transmission Line	Upgrade Type	Conductor Requirements
1	Halawa-Makalapa	New Line, 138 kV	
2	Halawa-Makalapa	Re-conductor	One circuit, re-conductor to double-bundled 795 AAC
3	Makalapa-Waiau	New Line, 138 kV	One circuit, with 1950 AAC conductor
4	Halawa-Iwilei	Re-conductor	One circuit, re-conductor to double-bundled 795 AAC
5	Halawa-School	Re-conductor	One circuit, re-conductor to double-bundled 795 AAC

6	Halawa-Ko`olau	Re-conductor	One circuit, re-conductor to double-bundled 795 AAC

Table 10-3 Summary of 138 kV Transmission Line Upgrade Requirements for hosting 600 MW Off-Shore Wind at Koolau Substation with Transmission Network Expansion Option 1

No.	Transmission Line	Upgrade Type	Conductor Requirements
1	Halawa-Ko`olau	Re-conductor	One circuit, re-conductor to double-bundled 795 AAC
2	Halawa-Ko`olau	New Line, 138 kV	One circuit, with 1950 AAC conductor
3	Ko`olau-Waiau #1	Re-conductor	One circuit, re-conductor to double-bundled 795 AAC
4	Ko`olau-Waiau #2	Re-conductor	One circuit, re-conductor to double-bundled 795 AAC

10.2. Transmission Upgrade Requirements Identified with Transmission Network Expansion Option 2

Single line diagrams of hosting 138 kV substations with upgrades required for REZ and off-shore wind interconnection, with Transmission Network Expansion Option 2 (red represents required upgrade, and black represents existing system) are shown as following.

For Ho`ohana substation, the upgrade requirements are the same as the requirements identified in the Transmission Network Expansion Option 1 study, which is shown in Figure 26.

For Ewa Nui substation, the upgrade requirements are the same as the requirements identified in the Transmission Network Expansion Option 1 study, which is shown in Figure 27.

For Kahe substation, the upgrade requirements are shown in Figure 38, which only includes the upgrade requirements for interconnecting REZ Group 3.

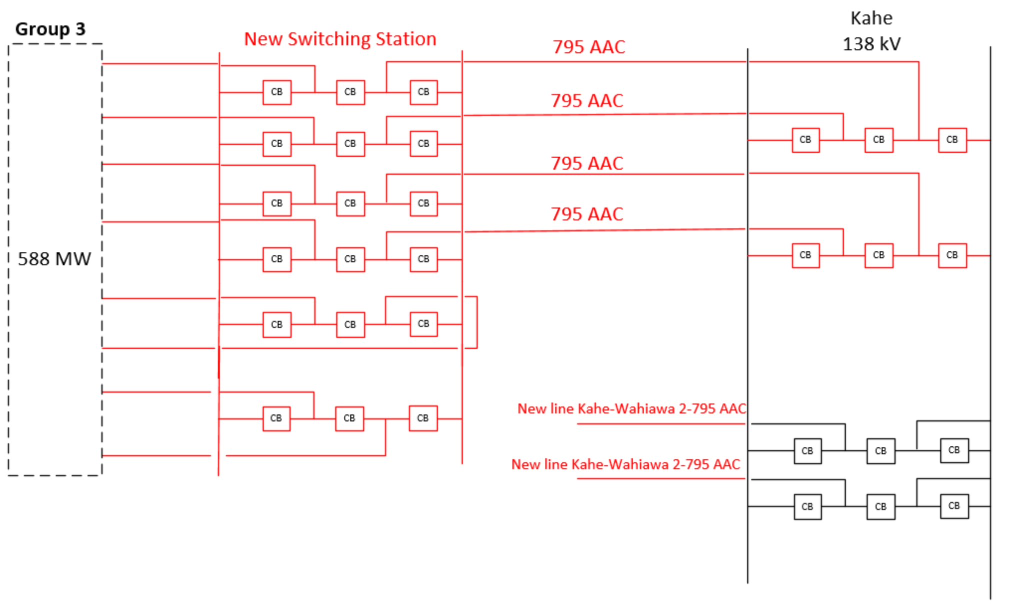


Figure 38 Kahe substation upgrade required for hosting REZ Group 3, Transmission Network Expansion Option 2

For Waiau substation, the upgrade requirements are the same as the requirements identified in the Transmission Network Expansion Option 1 study, which is shown in Figure 29.

For Halawa substation, the upgrade requirements are the same as the requirements identified in the Transmission Network Expansion Option 1 study, which is shown in Figure 30, which only includes the upgrade requirements for interconnecting REZ Group 5.

For Ko`olau substation, the upgrade requirements are the same as the requirements identified in the Transmission Network Expansion Option 1 study, which is shown in Figure 31.

For Wahiawa substation, the upgrade requirements are shown in Figure 39, which only include the upgrade requirements for interconnecting REZ Group 8.

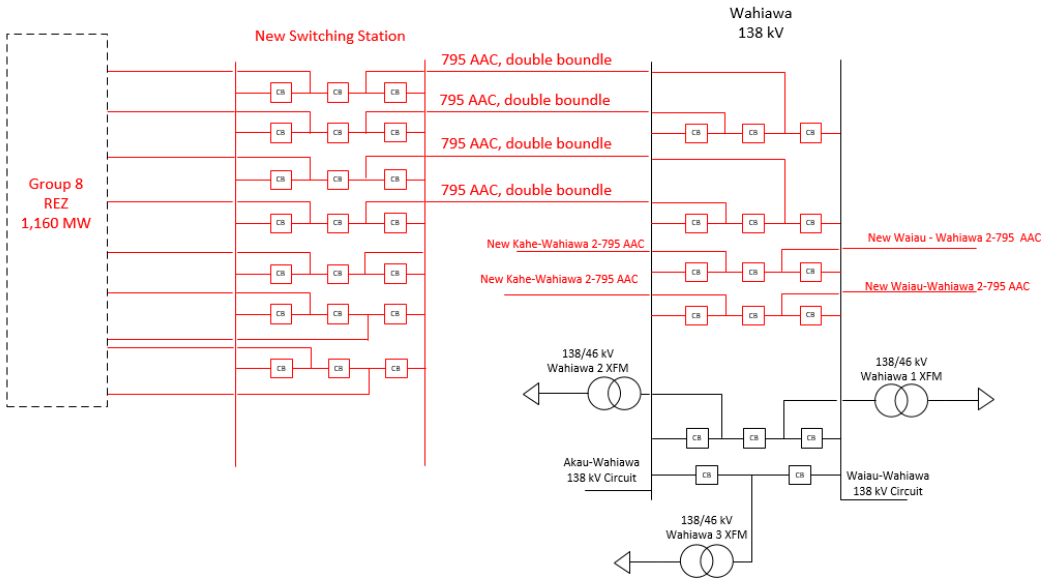


Figure 39 Wahiawa substation upgrade required for hosting REZ Group 8, Transmission Network Expansion Option 2

For the interconnection of the 600 MW off-shore wind, the infrastructure upgrade requirements are the same as what are identified in the Transmission Network Expansion Option 1, which is shown in Figure 33 to Figure 37.

The summary of existing transmission infrastructure upgrade requirements for hosting REZ 8 groups is listed in Table 10-4. The upgrade requirements for interconnecting the off-shore wind farm are the same as what are identified in the Transmission Network Expansion Option 1 study, which are summarized in Table 10-2 and Table 10-3.

Table 10-4 Summary of 138 kV Transmission Line Upgrade Requirements for hosting REZ 8 Groups with Transmission Network Expansion Option 2

No.	Transmission Line	Upgrade Type	Conductor Requirements
1	Kahe-Akau-Hema-Wahiawa	Re-conductor	One circuit, re-conductor to double-bundled 795 AAC
2	Wahiawa-Kahe	New Line, 138 kV	Two circuits, with double-bundled 795 AAC
3	Wahiawa-Waiau	Re-conductor	One circuit, re-conductor to double-bundled 795 AAC
4	Wahiawa-Waiau	New Line, 138 kV	Two circuits, with double-bundled 795 AAC
5	Waiau-Makalap #1	Re-conductor	One circuit, re-conductor to double-bundled 795 AAC

10.3. Transmission Upgrade Requirements Identified with Transmission Network Expansion Option 3

Single line diagrams of hosting 138 kV substations with upgrades required for REZ and off-shore wind interconnection, with Transmission Network Expansion Option 3 (color red represent required upgrade, and color black represent existing system) are shown as following.

For Ho`ohana substation, the upgrade requirements are the same as the requirements identified in the Transmission Network Expansion Option 1 study, which is shown in Figure 26.

For Ewa Nui substation, the upgrade requirements are the same as the requirements identified in the Transmission Network Expansion Option 1 study, which is shown in Figure 27.

For Kahe substation, the upgrade requirements are shown in Figure 40, which only includes the upgrade requirements for interconnecting REZ Group 3.

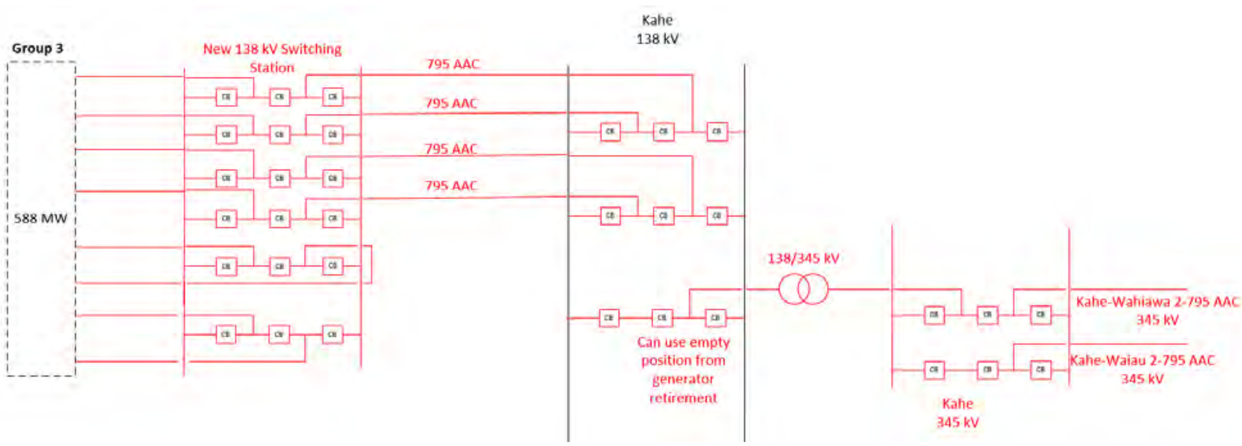


Figure 40 Kahe substation upgrade required for hosting REZ Group 3, Transmission Network Expansion Option 3

For Waiau substation, the upgrade requirements are shown in Figure 40, which only includes the upgrade requirements for interconnecting REZ Group 4.

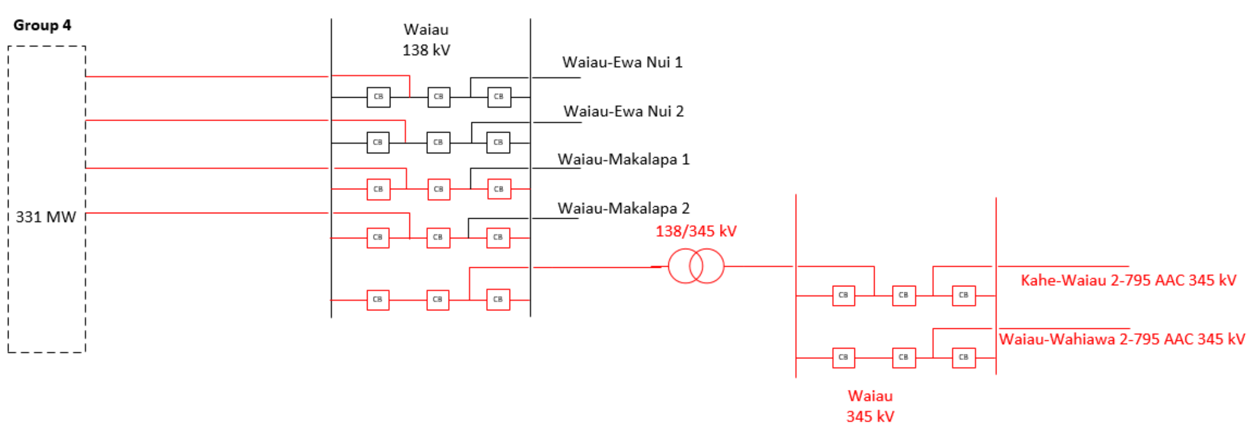


Figure 41 Waiau substation upgrade required for hosting REZ Group 4, Transmission Network Expansion Option 3

For Halawa substation, the upgrade requirements are the same as the requirements identified in the Transmission Network Expansion Option 1 study, which is shown in Figure 30, which only includes the upgrade requirements for interconnecting REZ Group 5.

For Ko`olau substation, the upgrade requirements are the same as the requirements identified in the Transmission Network Expansion Option 1 study, which is shown in Figure 31.

For Wahiawa substation, the upgrade requirements are shown in Figure 42, which only include the upgrade requirements for interconnecting REZ Group 8. It is worth noting that in this Transmission Network Expansion option, the 1,160 MW renewable potential is considered to be interconnected at 345 kV level.

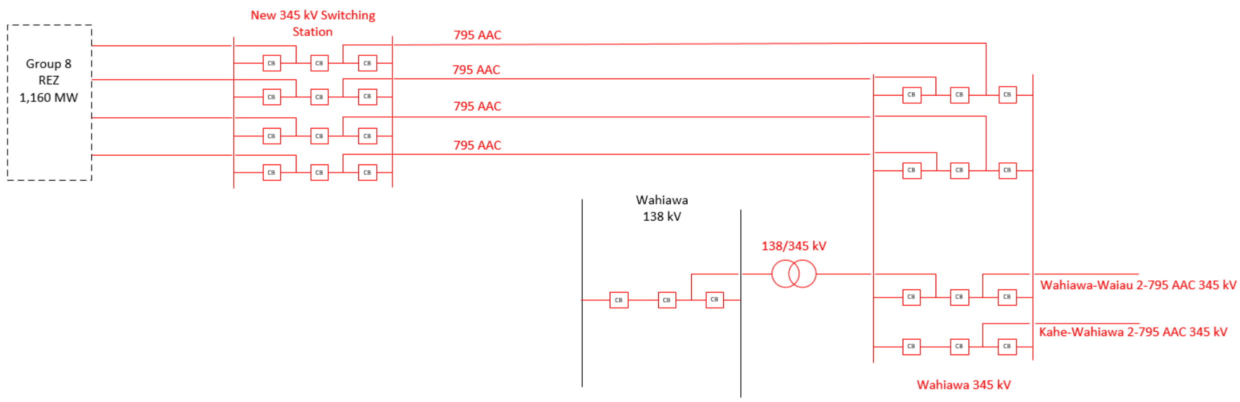


Figure 42 Wahiawa substation upgrade required for hosting REZ Group 8, Transmission Network Expansion Option 3

List of transmission infrastructure requirement for this options for interconnecting all groups of REZ is summarized in Table 5-4. For the 600 MW off-shore wind interconnection, it is considered to interconnecting the off-shore wind to system through the Kahe 345 kV bus. Single line diagram for this scenario is shown as Figure 43.

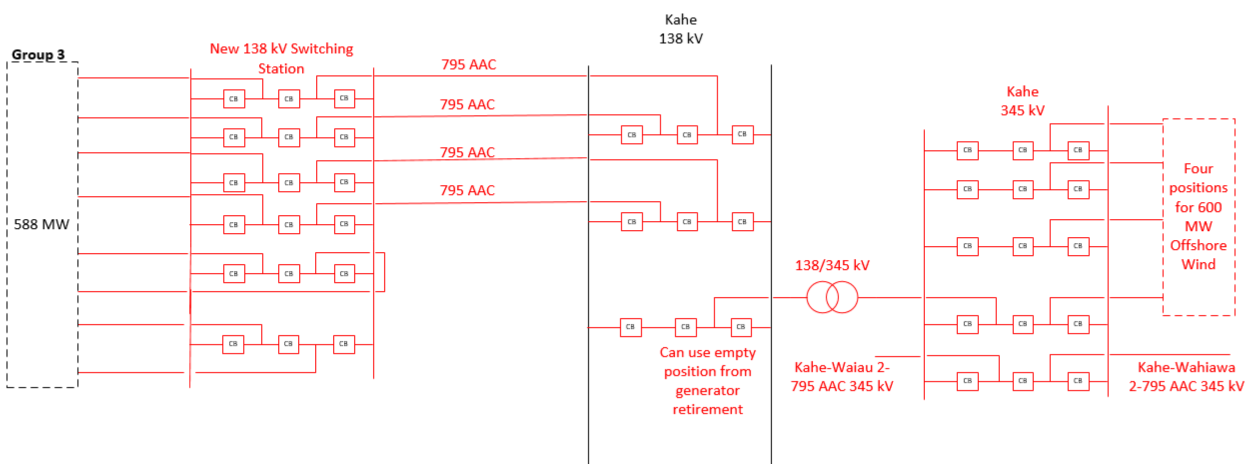


Figure 43 Kahe substation upgrade required for hosting REZ Group 3 and the off-shore wind (through the 345 kV bus), Transmission Network Expansion Option 3

Transmission Network Expansion requirements for interconnection the off-shore wind to Halawa substation or Waiau substation (through 138 kV connection) are the same as what are identified in Transmission Network Expansion Option 1 and 2 study.

10.4. Appendix – Maui Island REZ Interconnection

Single line diagrams of hosting 69 kV substation with upgrades required for REZ interconnection, (color red represent required upgrade, and color black represent existing system) are shown as following. It is worth noting that re-conductor type of upgrade is not shown in the following single line diagrams. All these upgrades apply for both Transmission Network Expansion Option 1 and Option 2.

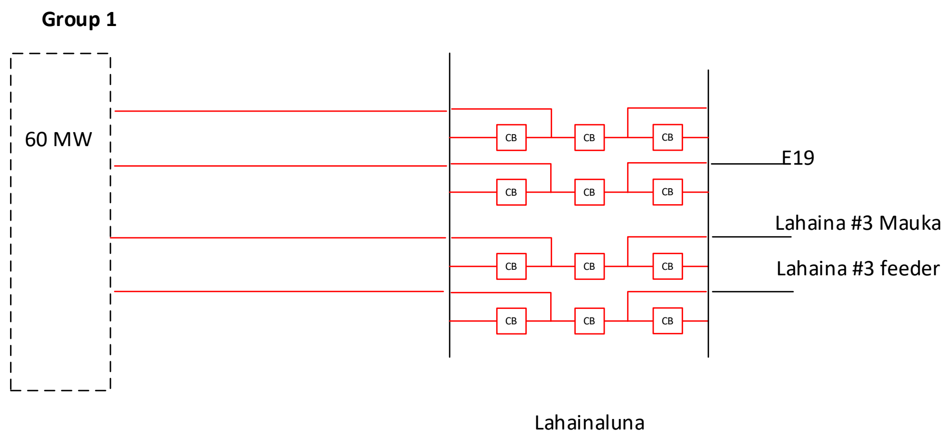


Figure 44 Lahainaluna substation upgrade required for hosting REZ Group 1

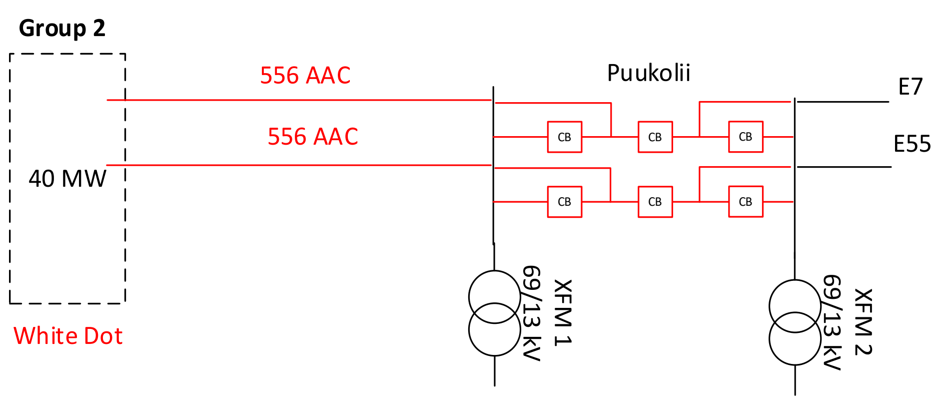


Figure 45 Puukolii substation upgrade required for hosting REZ Group 2

Hawaiian Electric

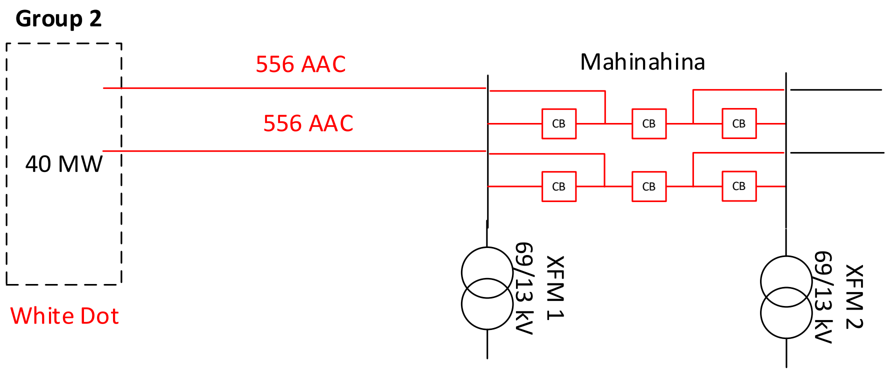


Figure 46 Mahinahina substation upgrade required for hosting REZ Group 2

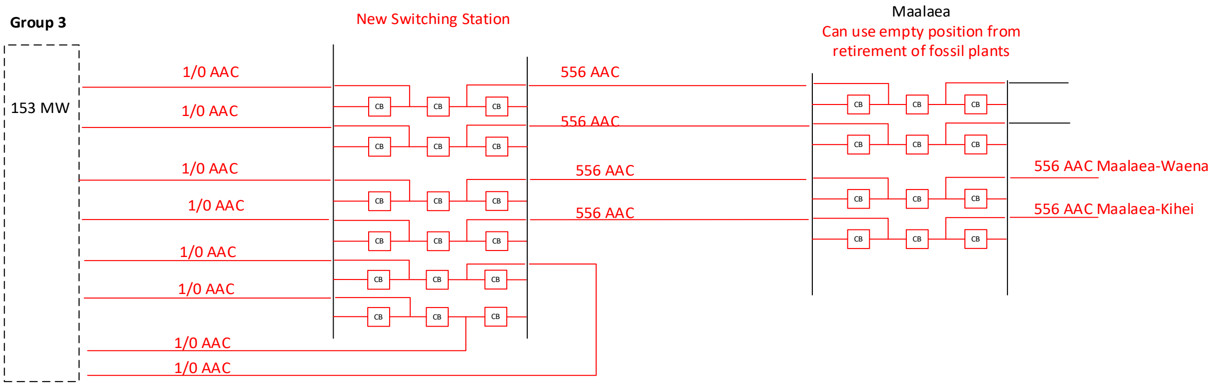


Figure 47 Maalaea substation upgrade required for hosting REZ Group 3

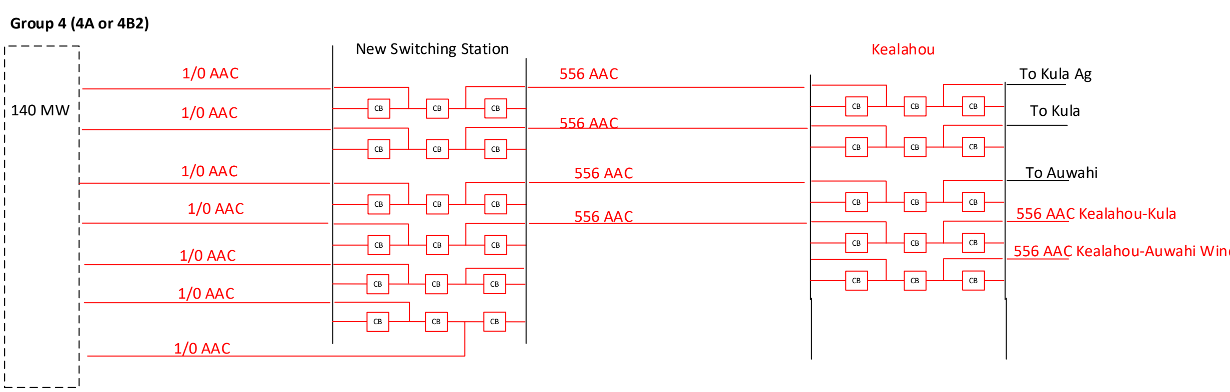


Figure 48 Kealahou substation upgrade required for hosting REZ Group 4A

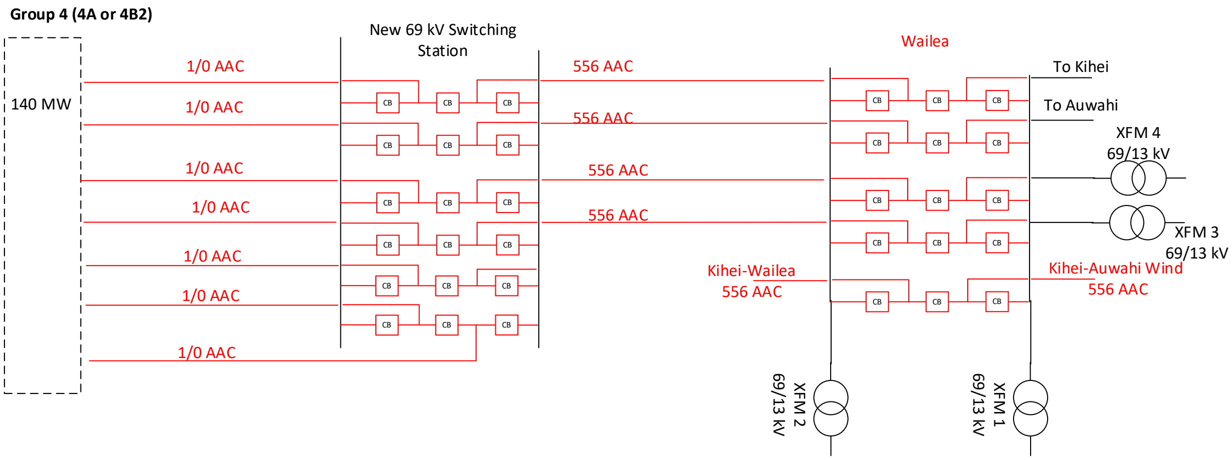


Figure 49 Wailea substation upgrade required for hosting REZ Group 4A

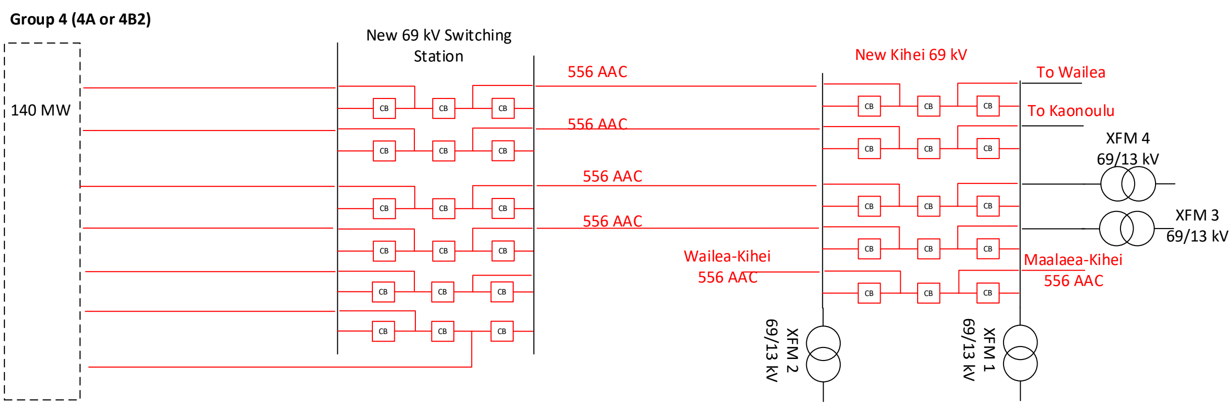


Figure 50 Kihei substation upgrade required for hosting REZ Group 4A

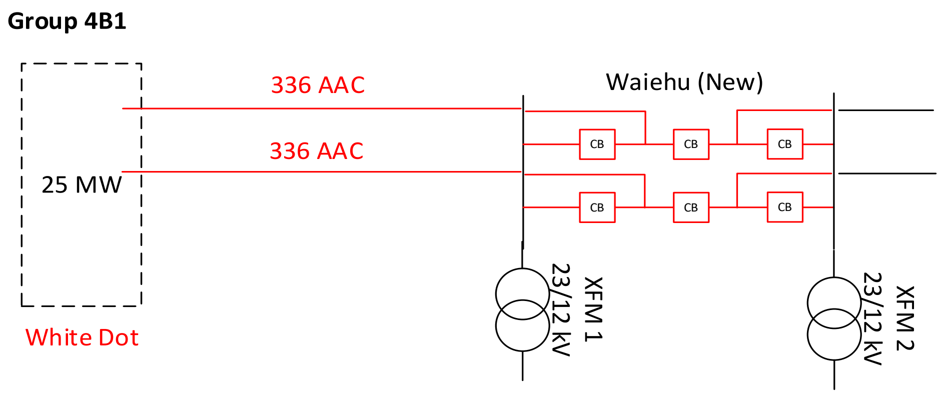


Figure 51 Waiehu substation upgrade required for hosting REZ Group 4B1

Hawaiian Electric

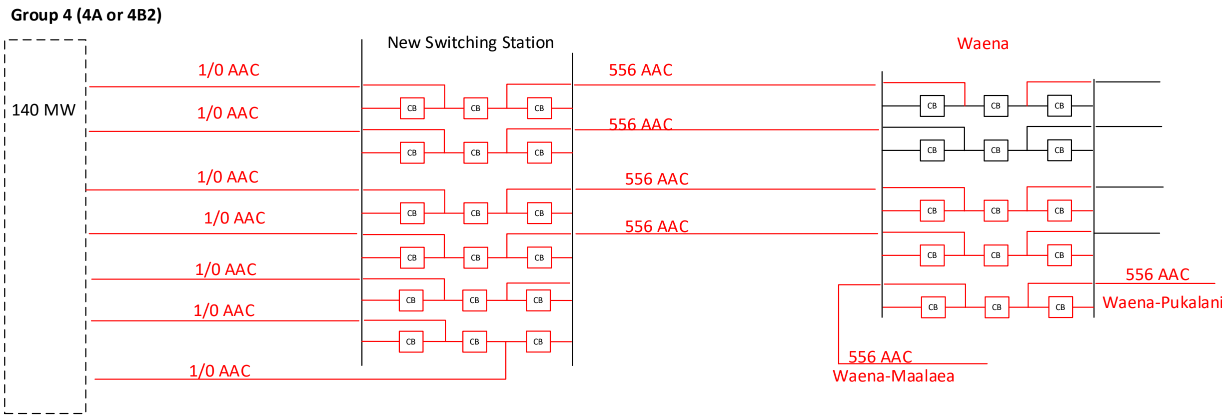


Figure 52 Waena substation upgrade required for hosting REZ Group 4B2

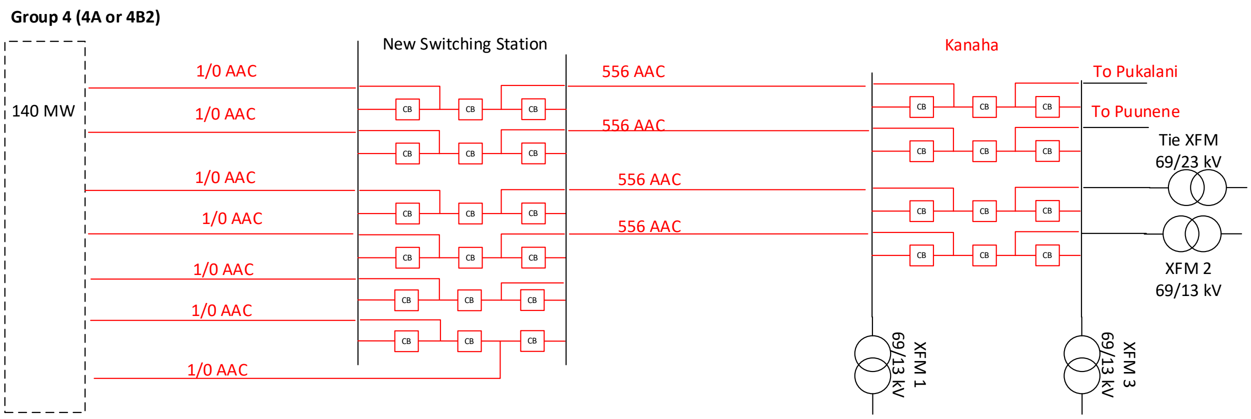


Figure 53 Kanaha substation upgrade required for hosting REZ Group 4B2

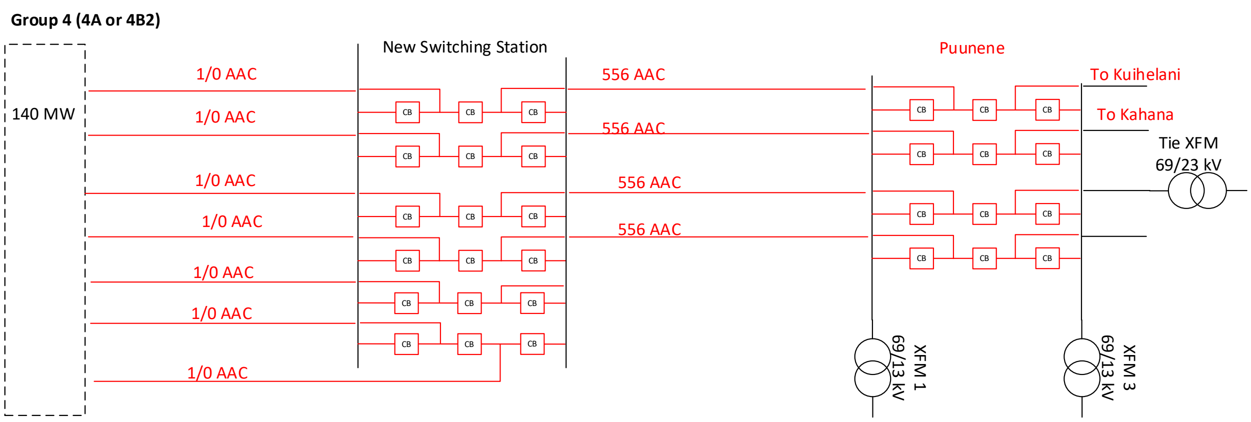


Figure 54 Puunene substation upgrade required for hosting REZ Group 4B2

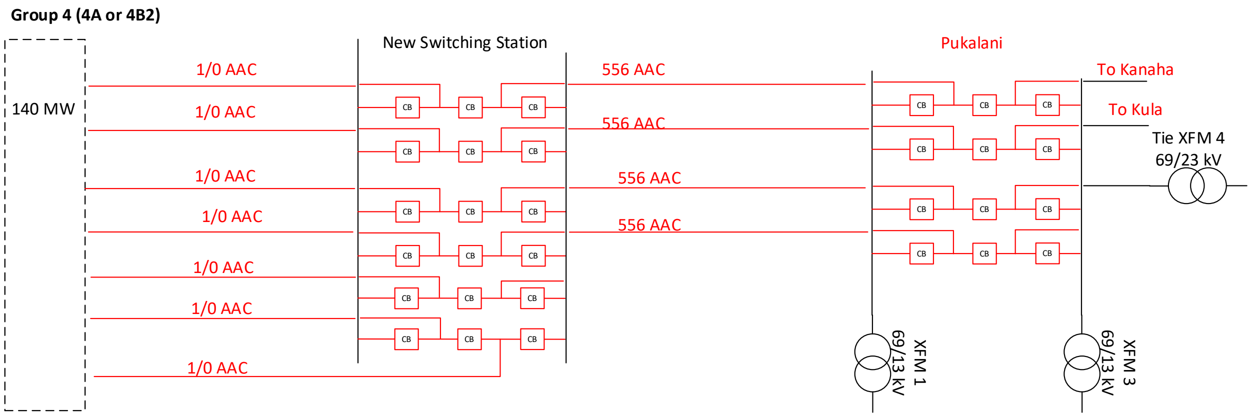


Figure 55 Pukalani substation upgrade required for hosting REZ Group 4B2

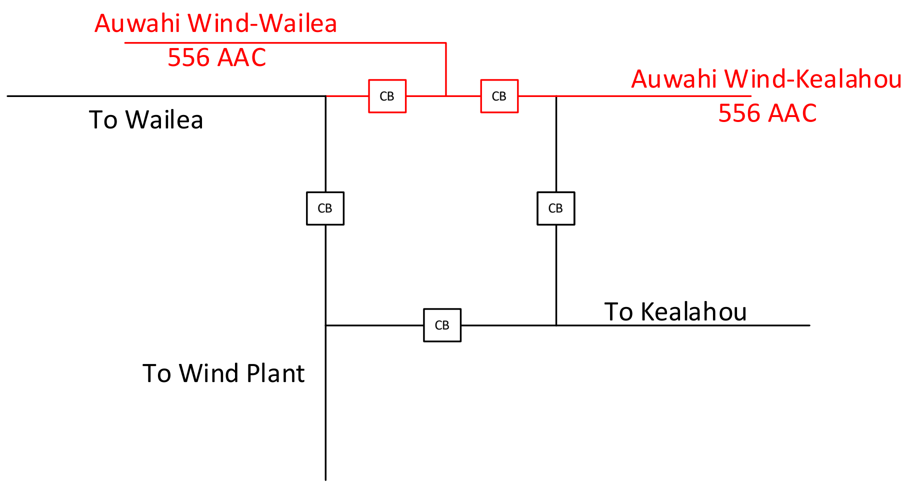


Figure 56 Auwahi Wind substation upgrade required for hosting REZ Group 4A

Following 23 kV transmission line upgrade is only applied for scenarios with Transmission Network Expansion Option 1.

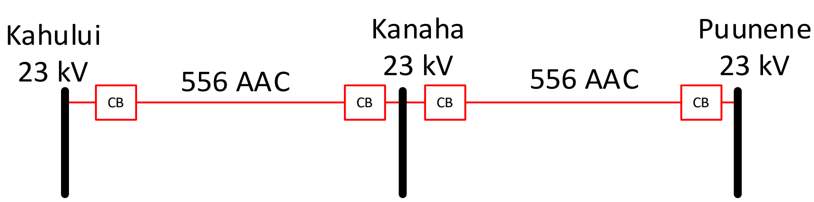


Figure 57 New 23 kV lines required on 23 kV transmission system with Transmission Network Expansion Option 1

10.5. Appendix – Hawai'i Island REZ Interconnection

Single line diagrams of hosting 69 kV substation with upgrades required for REZ interconnection, (color red represent required upgrade, and color black represent existing system) are shown as following. It is worth noting that re-conductor type of upgrade is not shown in the following single line diagrams. All these upgrades apply for both Transmission Network Expansion Option 1 and Option 2.

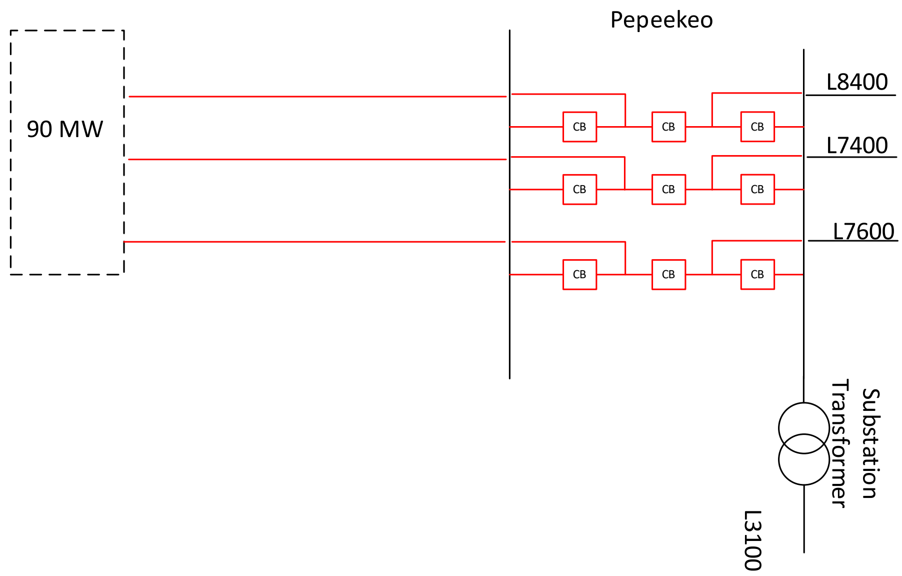


Figure 58 Pepeekeo substation upgrade required for hosting REZ Group 1, REZ Option 1 & 2

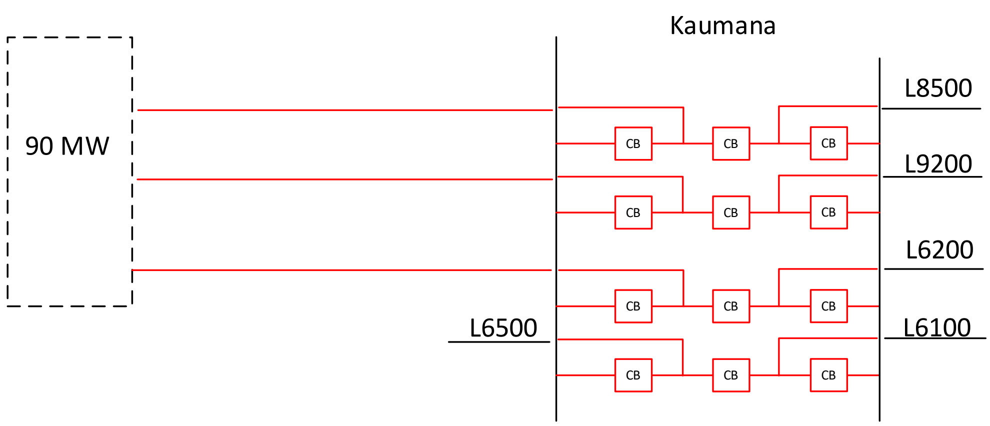


Figure 59 Kaumana substation upgrade required for hosting REZ Group 1, REZ Option 1 & 2

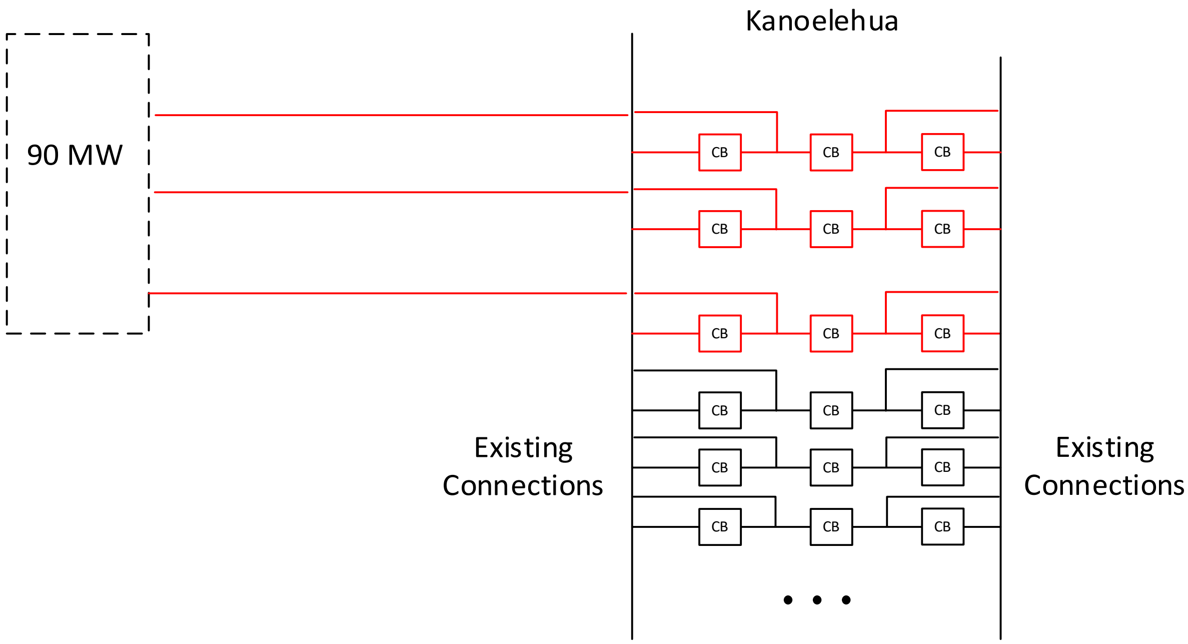


Figure 60 Kanoelehua substation upgrade required for hosting REZ Group 1, REZ Option 1 & 2

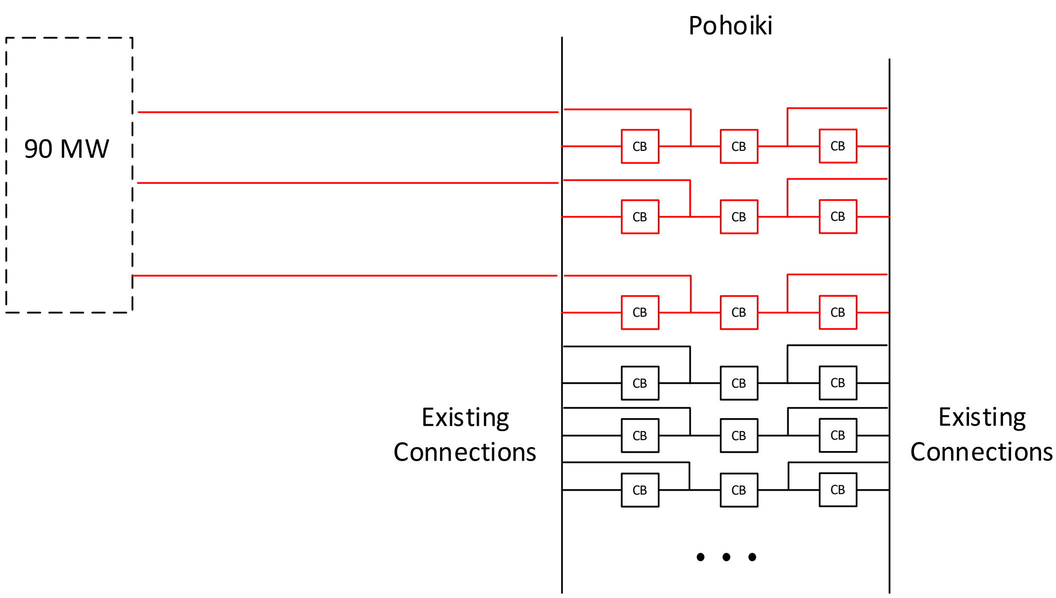


Figure 61 Pohoiki substation upgrade required for hosting REZ Group 1, REZ Option 1 & 2

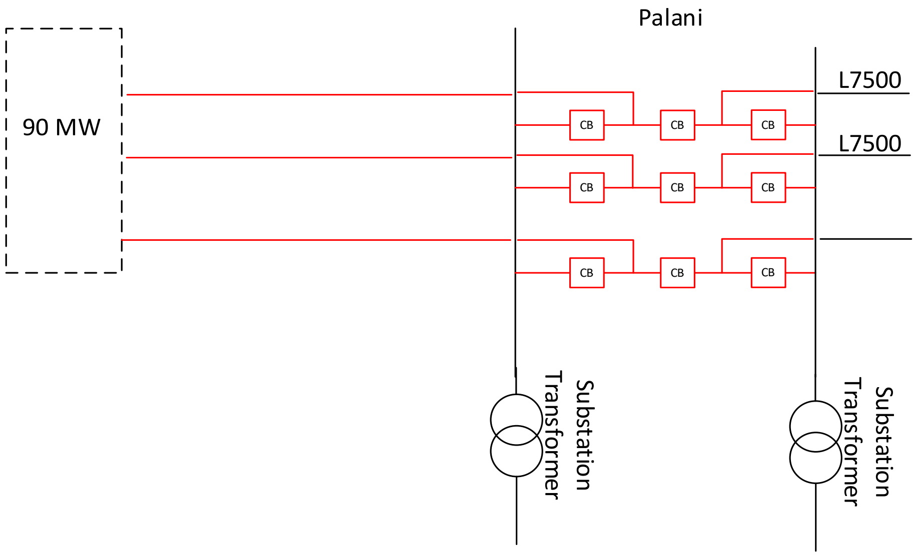


Figure 62 Palani substation upgrade required for hosting REZ Group 2, REZ Option 1 & 2

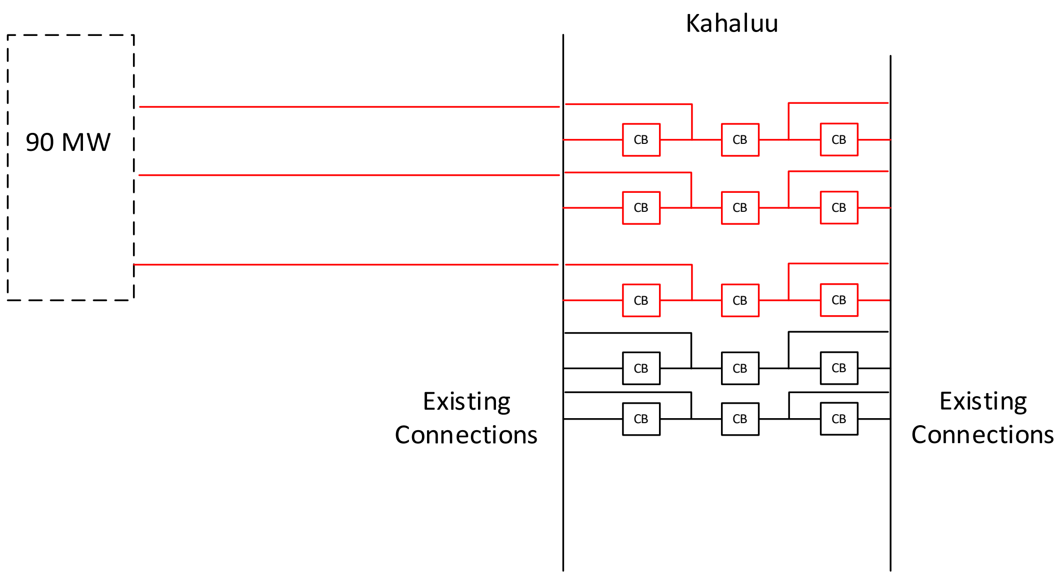


Figure 63 Kahaluu substation upgrade required for hosting REZ Group 2, REZ Option 1 & 2

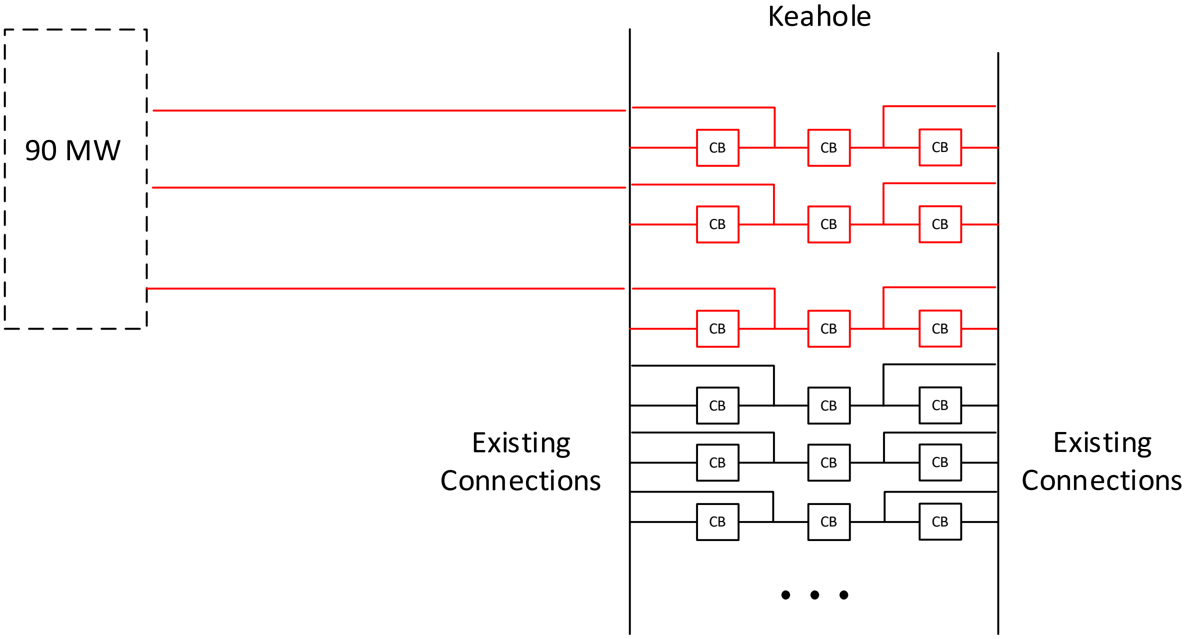


Figure 64 Kahaluu substation upgrade required for hosting REZ Group 2, REZ Option 1 & 2

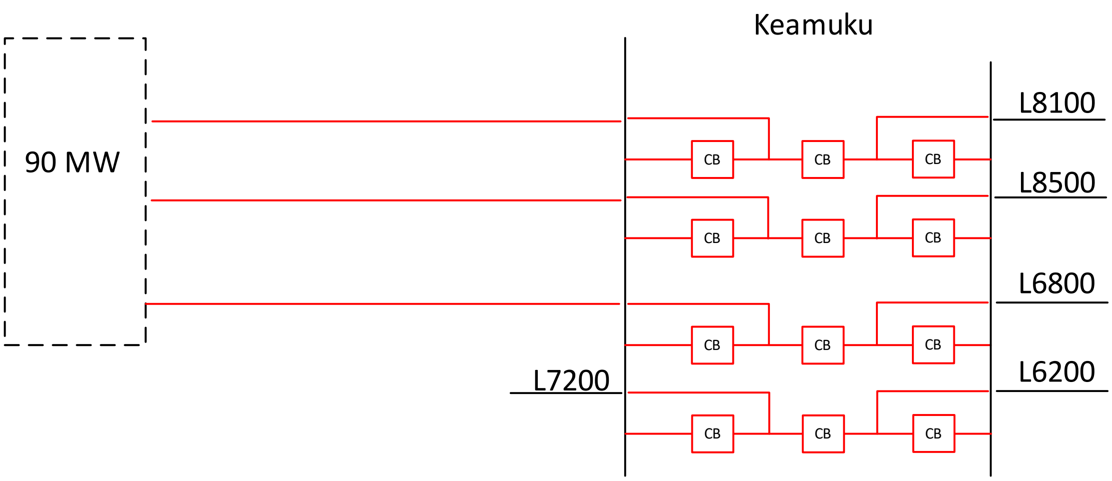


Figure 65 Keamuku substation upgrade required for hosting REZ Group 2, REZ Option 1

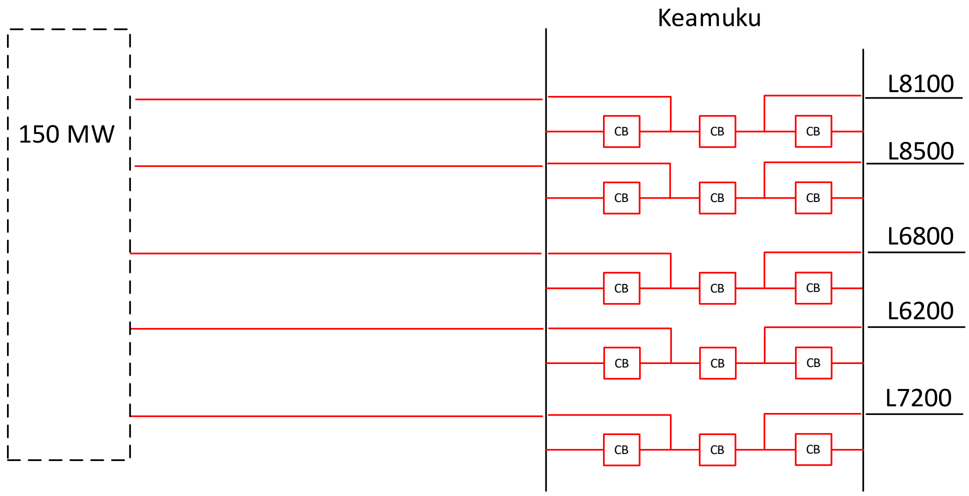


Figure 66 Keamuku substation upgrade required for hosting REZ Group 3, REZ Option 2

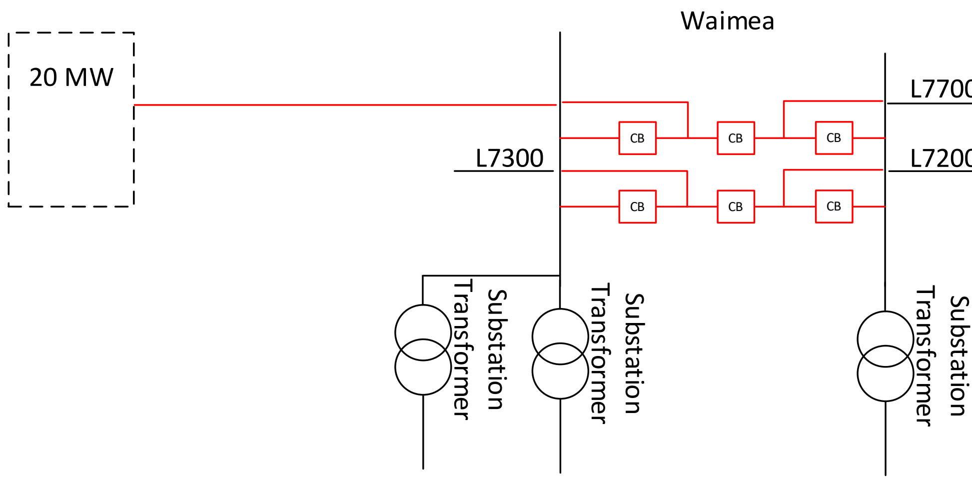


Figure 67 Waimea substation upgrade required for hosting REZ Group 4, REZ Option 2

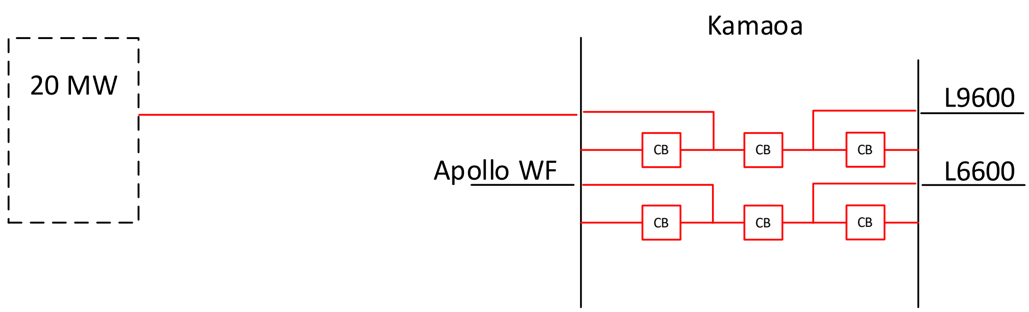


Figure 68 Waimea substation upgrade required for hosting REZ Group 5, REZ Option 2

11. Appendix B – IGP Technical Advisory Panel (TAP) Feedback

The Company presented the REZ Study methodology to the IGP TAP Transmission Subgroup on 10/1/21. This section includes the TAP Transmission Subgroup's notes, which includes feedback and Company responses. The meeting notes refer to a presentation or slide deck, which is the October 6, 2021 IGP STWG meeting. Feedback incorporated into this revision of the REZ study are denoted with this icon (and section number below, if applicable): #.#.#

The Company will continue to seek guidance and input as needed from the TAP to continue refining future revisions of the study.

IGP TAP Transmission Subgroup

Feedback on REZ Study

10/6/2021

This feedback to HECO is based on HECO's slides and presentation on their initial REZ Study on 10/1/2021.

TAP members attending: Andy Hoke (NREL, Chair), Dana Cabbell (SCE), Matt Richwine (Telos/HNEI), Deepak Ramasubramanian (EPRI). Not able to attend: Debbie Lew (ESIG)

HECO presenters: Ken Aramaki, Li Yu, Addison Li, Marc Asano, Chris Lau

TAP feedback and comments are divided into three categories:

1. Informational – no action needed.
2. Suggest revising REZ study before November 1 submission deadline.
3. Consider feedback for future portions of the IGP process (after the Nov 1 deadline).

11.1. TAP comments during meeting and HECO responses

Do the REZ zones consider environmental and community acceptance constraints?

- Response: Not at this stage. They are based on the NREL Alt 1 study with relaxed land slope constraints. A next step will obtain stakeholder feedback. We expect significant feedback from stakeholders, especially in certain potential REZ zones.

The REZ study examines a single point in time (evening peak). Is this because it is assumed to be the worst-case from transmission capacity perspective?

- Response: Yes.
- TAP follow up: Is this based on the assumption that future resources will include a BESS?

- Response: Yes, or that the resources will otherwise be made dispatchable.

What transmission constraints were considered? Thermal? Voltage?

- Response: Thermal (overcurrent) constraints are considered. Voltage constraints would be considered in a future more detailed study after receiving stakeholder input.

Were N-1 and N-1-1 contingencies considered in the REZ study power flows?

- Response: N-2 was considered for Oahu, and N-1 was considered for Maui and Hawaii. N-2 and N-1 scenarios were limited in scope for the study.
- TAP follow up: Future work could look at which contingencies drive needs for transmission upgrades in detail.

Why do you differentiate between "REZ enablement" and "Transmission network upgrades" separately rather than just considering the total transmission investment needed?

- Response: REZ enablement can be directly assigned to a project, whereas transmission upgrades may not be able to be. Also, see study results, where many REZ groups can be interconnected with only REZ enablement (i.e. a transmission intertie, and without network upgrades). We think this is a key finding.

How were the dispatches chosen? (For example, the dispatches in the screenshot below)

O`ahu REZ Study - REZ Dispatches

- Dispatch REZ Groups at Target MW
- Adding REZ MW each step, dispatching existing generation only if necessary
- Using power flow study to review all dispatch scenarios to determine Transmission Network Expansion requirements.

Dispatch #	Group 1 (120 MW)	Group 2 (324 MW)	Group 3 (588 MW)	Group 4 (331 MW)	Group 5 (609 MW)	Group 6 (147 MW)	Group 7 (66 MW)	Group 8 (1,160 MW)	Existing Generation
1	Full	Full	0	0	0	0	0	0	Supply remaining load
2	Full	Full	Full	0	0	0	0	0	Dispatch if necessary
3a	Full	Full	Full	Dispatch if necessary	0	0	0	0	0
3b	Dispatch if necessary	Dispatch if necessary	Full	Full	0	0	0	0	0
4	Dispatch if necessary	Dispatch if necessary	Dispatch if necessary	Full	Full	0	0	0	0
5	Dispatch if necessary	Dispatch if necessary	Dispatch if necessary	Full	Full	Full	0	0	0
6	Dispatch if necessary	Dispatch if necessary	Dispatch if necessary	Full	Full	Full	Full	0	0
7a	Dispatch if necessary	Dispatch if necessary	Dispatch if necessary	Dispatch if necessary	Full	Full	Full	300 MW	0
7b	Dispatch if necessary	Dispatch if necessary	Dispatch if necessary	Dispatch if necessary	Dispatch if necessary	Full	Full	800 MW	0
7c	Dispatch if necessary	Dispatch if necessary	Dispatch if necessary	Dispatch if necessary	Dispatch if necessary	Full	Full	Full	0
7d	Dispatch if necessary	Dispatch if necessary	Dispatch if necessary	240 MW	Dispatch if necessary	Dispatch if necessary	0	Full	0
7e	Dispatch if necessary	Dispatch if necessary	240 MW	Dispatch if necessary	Dispatch if necessary	Dispatch if necessary	0	Full	0
7f	Dispatch if necessary	240 MW	Dispatch if necessary	Dispatch if necessary	Dispatch if necessary	Dispatch if necessary	0	Full	0

- Response: We chose a range of dispatches designed to push each REZ zone to peak output.

- TAP follow up: The dispatches chosen are very important to the study outcome. Dispatches that draw from multiple REZ zones in parallel may produce a lower need for transmission.
- Response: Agreed. See the study outcomes. For Oahu, network upgrades are only needed for one REZ group (Group 8), and only beyond 300 MW. Beyond that threshold, Group 8 appears likely to be unfeasible. We will add a note about the 300 MW threshold to the slides. This REZ group is one of the most likely to see stakeholder pushback due to its location.

5.4.1

- TAP follow up: Agreed that this is an important finding. It can be important to consider not only active power redispatch but also reactive power dispatch and voltage profile across the network. This can determine network hosting capacity limits when considering multiple REZs at the same time.
- TAP follow up: The matrix on slide 17 is critical. Given the ~3x overbuild by nameplate of renewables, there should never be any case where any zone is at full export; it would be a very unusual and avoidable operating condition to have only one zone able to export and all other zones not able to. By all zones exporting and sharing the power generation, you're also distributing the power flows across the transmission infrastructure and reducing the chance of overloads. By considering any zone maxed out, it creates a local stress on the infrastructure and drives up the need for more infrastructure when in reality, the system may not need to be operated that way. Therefore, more dispatch conditions need to be evaluated where all zones are sharing the effort. Then when overloads are determined, shift more export to zones that do not as quickly overload the transmission system. This is very time-consuming to do manually; a chronological tool like PLEXOS with a nodal transmission model will greatly expedite such an analysis.

HECO should consider a chronological tool with an underlying transmission topology rather than a single point in time for this REZ analysis. For example, you need to make sure you have enough energy to charge the BESS. Also consider stacked BESS services. There are chronological tools that enable this, including iteration. It can be very hard to tell if you're close to a thermal constraint using manual dispatches since the constraints are binary.

5.4.8

- Response: For this initial analysis, the goal is to obtain approximate $/MW transmission costs for different REZ zones to inform the RESOLVE study. That would then be followed by PLEXOS, which is chronological. There will be future iterations that go into greater detail. We also need the basic REZ costs to get stakeholder input on potential REZ/PV locations. The process will be iterative.
- TAP follow up: The approach of ranking groups is a good one. However, the per-unitized cost estimate (screenshot below) misses the very important fact that the cost of transmission infrastructure does not vary linearly with the MW of REN integration; it varies in discrete steps (see hand sketch below). Linearizing it can result in a misleading metric that then feeds into the beginning of the RESOLVE-PLEXOS process shown on

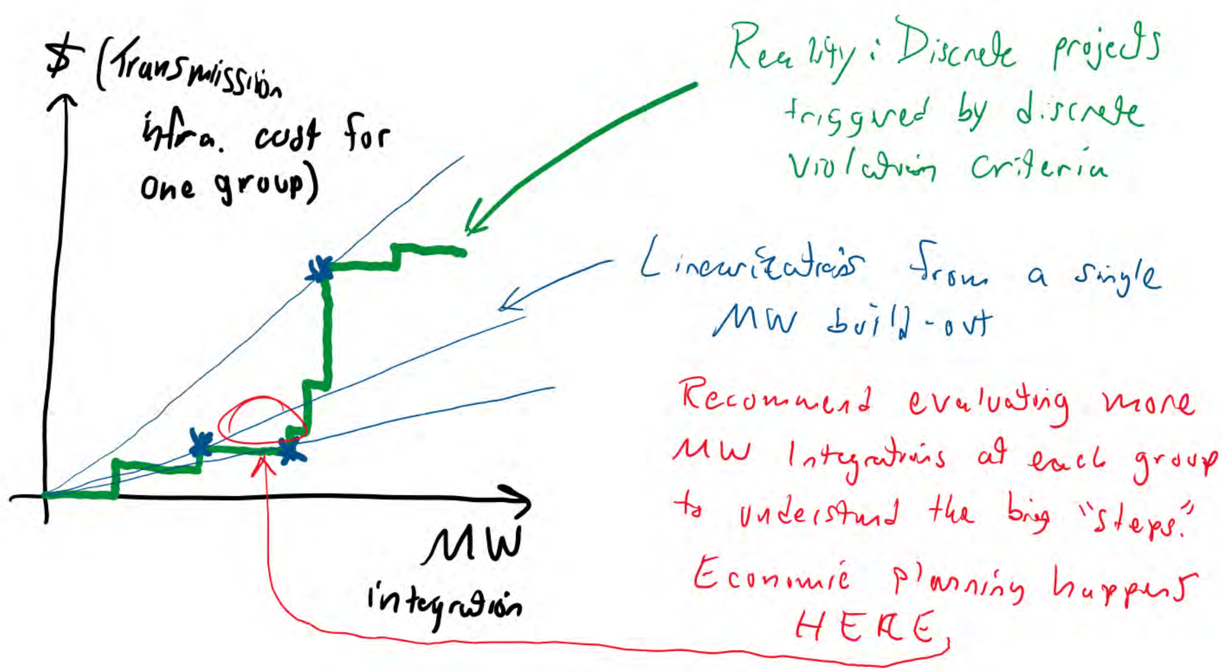
5.4.8

slide 57 and affects all downstream results. An evaluation of more MW integration levels is strongly recommended for Group 8, and recommended for the other groups as it may determine a different priority/cost for integration in each zone; for example, a stepwise $/MW curve for each group may be obtained, as sketched below. At the same time, the TAP recognizes that this is an initial pass at transmission cost estimation that will be refined in future steps.

O`ahu REZ Study – Cost Estimate

REZ Group	Group 1 (120 MW)	Group 2 (324 MW)	Group 3 (588 MW)	Group 4 (331 MW)	Group 5 (608 MW)	Group 6 (147 MW)	Group 7 (66 MW)	Group 8 (1,160 MW, 138 kV)	Group 8 (1,160 MW, 345 kV)
REZ Enablement Estimate ($MM)	24.5	86.0	818.8	286.9	1,076.1	95.9	N/A	1,410.9	1,083.5
Transmission Network Expansion ($MM) – See next slide	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1,331.1	1,331.1
Cost Estimate ($MM/MW)	0.20	0.27	1.39	0.96	1.77	0.65	N/A	2.36	2.08

•



When will non-transmission alternatives be considered?

- Response: This would be considered in a more detailed analysis later in the process.
- TAP follow up: Non-transmission alternatives such as power flow control devices (phase shifters, in-line compensators, etc) or even energy storage elements for congestion management can help with improving power flow across the network. Use of dynamic line rating technology to manage flows in operational time frame can also be considered.

Why was offshore wind studied only for Oahu? Perhaps because there is sufficient PV resource on other islands?

- Response: This was based on an NREL study that looked at Oahu.

Why is the Kahe offshore wind location not feasible?

5.4.5
- Response: It is not feasible with the 138 kV option, but it is feasible with the 345 kV loop. We will clarify this.

The 345 kV would be a new transmission voltage level for HECO meaning a need for a whole new class of equipment, spare parts, etc.

- Response: Agreed. The 345 kV option is only slightly cheaper than the other options, and that does not consider the costs of adding equipment for a new voltage class, so we do not think it will be the best option from a cost perspective.
- TAP follow up: 345 kV would also come with additional land costs if your existing substations don't have room.

Does adding 138 kV make sense for Maui? Perhaps this is subject to the same considerations as 345 kV on Maui, since it would be a new voltage level for that island?

Does the eventual PLEXOS study feedback into another iteration of RESOLVE?

- Response: Yes, that is a later part of the IGP process not shown on the slide in question (screenshot at end of this document).

The TAP agrees with the premise that it is preferable to provide planned interconnection points for renewables rather than piecemeal tapping of transmission lines as is currently being done.

Overall, the REZ study does a good job of establishing transmission limits that may impact amounts of PV that can be interconnected beyond what is seen from the resource analysis. HECO should also consider environmental concerns and community feedback before finalizing REZ plans.

- Response: Agreed. A next step is to engage with the communities.

What is the motivation for the study and the resources the study aims to facilitate?

- Response: We are working towards 100% renewables. Existing resource additions are already getting curtailed at times. Putting in new transmission lines is expected to take 10-20+ years. The IGP analysis needs to account for those long-term transmission costs.

11.2. Other TAP comments post-meeting:

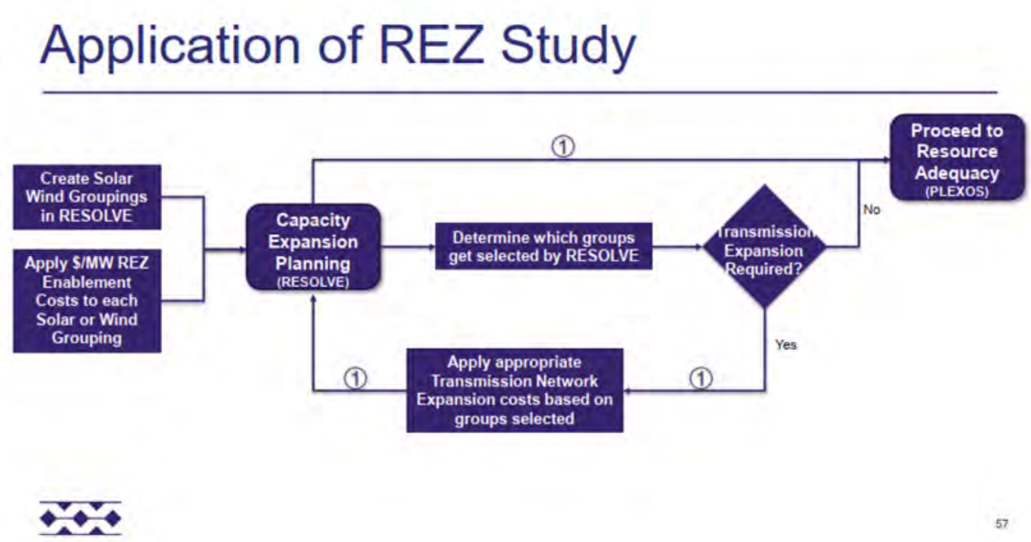
It appears the study did not include generation contribution from local DERs. Couldn't BTM DERs with batteries serve a significant portion of evening load in the future, thereby reducing some transmission constraints?

- Response: The study did not include contributions from DER. The study was narrowly focused on allowing large blocks of grid-scale resources. RESOLVE would pick DER and/or grid-scale resources, and follow-on studies would be needed to determine what those specific transmission requirements would be.

The study noted that dispatches that source all the generation from one area should be avoided. That makes sense, but what about a severe weather scenario that makes generation one side of an island unavailable? Does that need to be considered?

- Response: Good point and we will need to think about this one more. This was not studied in the REZ study but may be needed as a future sensitivity as well as in separate studies. In developing severe weather scenarios, would also need to take into account the full suite of resilience-related solutions to manage the impact.

The following flowchart was shown at the end of the presentation (from a different slide deck, we think) showing how the REZ study would feed into future steps using RESOLVE then PLEXOS. Perhaps that flowchart can be added to the presentation to help give context[9].



[9] *See* Slide 74. Presented to IGP STWG October 6, 2021: https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/stakeholder_technical/20211006_stwg_meeting_presentation_materials.pdf

12. Appendix C – IGP Stakeholder Technical Working Group (STWG) Feedback

The Company recognizes stakeholder engagement as an integral part of the IGP process. In an effort to proactively solicit stakeholder feedback on this report, the Company provided a draft report[10] to stakeholders for review and comment on October 1, 2021. The Company subsequently met with the STWG on October 6, 2021 to address questions and receive feedback from the stakeholders. Meeting minutes capturing feedback from the discussion and presentation materials from the meeting can be found on the IGP website.[11]

The Company received feedback from various Organizations, which is consolidated anonymously below. Feedback from stakeholders in this section are shown in **bold**, and the Company's response to the questions or feedback are shown in *italics*.

1. **At 13, please explain and provide an example of how Hawaiian electric will "develop very different transmission system upgrade options to cover all feasible options" in Step 4.**
    a. *For all three islands, the Transmission Network Expansions developed within this study are considered very different transmission system upgrade options. For example, in O`ahu, to export 1.2 GW potential on the north of Wahiawa 138 kV substation, three different options are considered in the study – Option 1: building new 138 kV loop between Wahiawa and Kahe based on new right-of-way, Option 2: re-conductor existing circuits and adding new circuits based on existing right-of-way among Kahe, Wahiawa, and Waiau, and Option 3: building 345 kV networks among Kahe, Waiau and Wahiawa. For Maui island and Hawai`i island, different REZ options are developed which required different transmission system upgrades.*
2. **At 19, please provide the sources and methodology for developing unit costs for transmission costs.**
    a. **How were the percentage-based cost adders (e.g. PM costs) calculated? Please provide a description of the projects that were analyzed to develop these percentages.**
        i. *Per unit costs are developed using expected labor hours, materials, and outside services for typical projects of certain voltages based on experiences on past projects. They are high-level and intended for use in Class 4 or 5 estimates.*
            1. *Maturity level of project definition deliverables = 0-15%*

[10] *See* https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/stakeholder_technical/20211001_renewable_energy_zones_draft.pdf

[11] *See* https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/stakeholder_technical/20211006_stwg_meeting_notes.pdf

2. *Purpose of estimate = Concept screening or study/feasibility*
3. *Methodology = capacity, equipment, judgement factors*
4. *Expected accuracy range = -50% to +100%*

ii. *Percentage-based cost adders were calculated as follows:*

1. *PM costs (5%) – Specific projects were not analyzed in determining this percentage. This was a rough estimate based on the types of projects considered. Each project will be unique and a more detailed look at the requirements of each project will be needed to determine the appropriate level of PM effort. This percentage was intended to acknowledge that there will likely be PM costs for each of these projects and to try to account for it in these high-level estimates.*
2. *Land/Permitting (10%) – Specific projects were not analyzed in determining this percentage. Land and permitting costs vary greatly depending on the requirements and location of each project. Land/permitting costs were added if new land was required for a new substation or substation expansion, if easements were required for new transmission lines, or if we expected major permitting requirements. No detailed analysis of the land/permitting costs were completed for this iteration of the study. The percentage was intended to acknowledge that there will be land/permitting costs for certain projects and to try to account for it in these high-level estimates.*

3. **Are the dispatch scenarios organized in a particular order, such as cost, difficulty to interconnect, and/or capacity size?**
    a. *There is no particular order for organizing dispatch scenarios. All dispatch scenarios are designed by considering all REZ Groups to be able to be dispatched at the potential MW values.*
4. **How will the cost estimates for REZ groups be communicated to developers?**
    a. *The Company intends to provide this REZ Study as well as any revisions to future developers, which will include cost estimates for developers to review.*
5. **Will Hawaiian Electric pursue any of the transmission upgrades proactively (i.e. before projects are identified through an RFP?)**
    a. *There are several major steps that need to take place before pursuing transmission upgrades identified in this study. In the near-term, the results of this study will be used to inform the IGP Process by providing more complete estimates of transmission costs needed to implement various renewable energy scenarios. The information from these analyses will help to support broad policy-related discussions, while including community and stakeholders, to understand the transmission-related requirements to attain higher levels of grid-scale renewable energy. These discussions and further study(s) will provide an overall plan, which can be incrementally built-to as renewable resources continue to be implemented.*
6. **Will Hawaiian Electric consider targeted RFPs limited to select REZ groups?**

a. *Yes, if the REZ work and further community and stakeholder feedback support targeted locations, the Company will consider future targeted RFPs based upon the information developed in the REZ study.*

7. **How would costs of the transmission projects that serve new and existing resources be shared by IPPs and the utility? For future projects, how will Hawaiian Electric mitigate the risk of projects dropping out and potentially resulting in cost-shares of REZ enablements increasing?**
   a. *This would need to be reviewed on a case-by-case basis. For example, if a certain REZ development required transmission upgrades prior to the implementation of renewable projects that require it, the Utility may request recovery ahead of approvals of PPAs for the resources, which would place costs at risk. However, there may be instances where transmission upgrades could be started concurrent to an RFP of a certain REZ, which would mitigate risk by knowing whether developers are pursuing renewable projects in the zone. Based on this variation, the answer will depend upon the specific situation, which is yet to be determined.*
8. **For each region identified in the REZ analysis, please explain how much additional capacity can be integrated into the existing transmission system without transmission upgrades or expansion (i.e., existing transmission interconnection capacity).**
   a. *The interconnection of REZ groups, at minimum, require an interconnection to an existing switching station, which generally require an expansion of a switching station to support the interconnection of the resource(s). The REZ study provides cost estimates to expand or build switching stations, and extend lines to the REZ(s). Based on stakeholder and TAP feedback, this version of the study has been revised to provide cost information for incrementally adding capacity to certain REZs.*
9. **Please explain how feasibility (e.g., land use, community acceptance, affordability, etc.) of transmission upgrades/expansion will be incorporated into the REZ analysis.**
   a. *The Company will rely on stakeholder and community feedback to prioritize REZ groups and/or revise REZ groups. Future REZ analyses will adjust the scope of the study based on feedback from the community and stakeholders.*
10. **We request additional information on how HECO is estimating the cost to upgrade infrastructure based on your analysis.**
    a. *In addition to the unit costs provided in Section 3.3 of this report, the following information is provided.*
    b. *Substation estimates*
       i. *Based on past experience with similar projects.*
       ii. *Based on a high-level look at the existing substations to check feasibility of expansion.*
       iii. *If expansion of existing substation not possible, assumed a full rebuild of the substation nearby if feasible or eliminated option.*
       iv. *Assumed land/permitting could be obtained.*
    c. *T&D estimates*
       i. *High-level routing of new transmission lines was completed to determine feasible routes.*

ii. *New lines were run from the existing substations to either a new substation in the REZ or to the edge of an REZ.*
iii. *If lines were running to the edge of an REZ, they ended at different points of zone so that projects in any part of the zone could interconnect to a line.*
iv. *If the substation (new or existing) that renewable projects would interconnect to was already in the zone, then it was assumed Proposers of projects would run the line to the substation and no costs were included in this study.*
v. *Assumes there is space in the ground for UG facilities and poles along the routes.*
vi. *Assumes easements/permitting can be obtained for new transmission lines.*

11. **We recommend that in future studies HECO look at the same scenarios (before and after upgrades) with transient stability studies (to include advanced inverter modeling and interconnections) and economic dispatch studies across many scenarios.**
    a. *The Company agrees and stability analyses will be included in future REZ studies and/or as part of the System Security step in the IGP process should certain REZ be selected by the modeling.*
12. **For clarification, is the current conclusion that OSW [Offshore Wind] could not be interconnected at Kahe or Halawa substations, because those substations cannot be expanded? And if so, are there other stations besides Ko'olau which could accommodate interconnection of OSW?**
    a. *Correct, the analysis found that interconnecting 400MW or 600 MW at Kahe, Halawa, and Iwilei are not feasible. The interconnection at Kahe substation required an expansion at Ho`ohana substation, which is not feasible due to space constraints. The interconnection at Halawa substation required an expansion at Makalapa substation, which is also not feasible due to space limitations. Iwilei substation, was found to also have space constraints for the required expansion. Koʻolau substation was found to be the most feasible option to accommodate an interconnection of OSW.*
13. **We appreciate the analysis of the sensitivity for 600 MW of OSW. Given that the majority of the transmission network upgrades are driven by new 138 kV transmission lines that would be required, what capacity of OSW could be accommodated at each identified substation without adding new transmission lines? This has practical and planning implications. For instance, it could be more economical to downsize OSW interconnection capacity or to interconnect to more than one substation at a lower capacity. Understanding the capacity of the existing system to accommodate OSW (to minimize upgrades) could help both the Company and developers arrive at proposed projects which could be more cost-effective for customers.**
    a. *As part of a REZ analysis, an assumption was made to keep the scope and schedule of interconnecting 600MW of OSW consistent with the BOEM/NREL study, which meant the interconnection was potentially after the implementation of Groups 1-*

8. However, given the sizes of REZs 1-8, it can be reasonably assumed that OSW of the size of these REZs, interconnections at these points could be made. Note that such OSW interconnections would displace the ability to add onshore renewables within these REZ unless additional transmission assessment and solution options are developed.

14. **Regarding timing, the REZ analysis currently assumes that OSW would be interconnected after the eight groups of onshore REZ. what would be the required transmission network expansions if OSW we're interconnected to a substation prior to the onshore REZ upgrades? For example, if a substation were identified for OSW only, instead of onshore REZ, would less transmission upgrades be required and how might that impact costs?**
    a. *See response to question 13 above. OSW could proceed similar to on shore renewables developed within an REZ. This REZ analysis identifies transmission requirements under a specific set of assumptions of the level of renewable potential that could be developed within a geographical area. If more potential exists, additional REZ analysis can be performed to determine the transmission requirements for this higher level of renewable energy systems.*

EXHIBIT 3

Location-Based Distribution Forecasts

Hawaiian Electric

Location-Based Distribution Forecasts

November 2021

Table of Contents

Table of Figures

1 Introduction

1.1 OVERVIEW

This document describes the development of the location-based circuit level forecasts that will be used as part of the Distribution Planning Process and Integrated Grid Planning ("IGP") process. The Distribution Planning Process as described in the *Distribution Planning Methodology* document[1,2] was developed in collaboration with stakeholder and customer engagement through the Distribution Planning Working Group ("DPWG") and reviewed by the Technical Advisory Panel. The document was developed to identify the steps and tools used by the Company to analyze the distribution system and determine grid needs required to serve load growth and safely interconnect distributed energy resources ("DER") while maintaining power quality and reliability for all customers.

The Distribution Planning Process is comprised of four stages: forecast, analysis, solution options, and evaluation.

1. **Forecast Stage**: Develop circuit-level forecasts based on the corporate demand forecast.
2. **Analysis Stage**: Determine the adequacy of the distribution system.
3. **Solution Options Stage**: Identify the grid needs requirements.
4. **Evaluation Stage**: Evaluation of solutions.

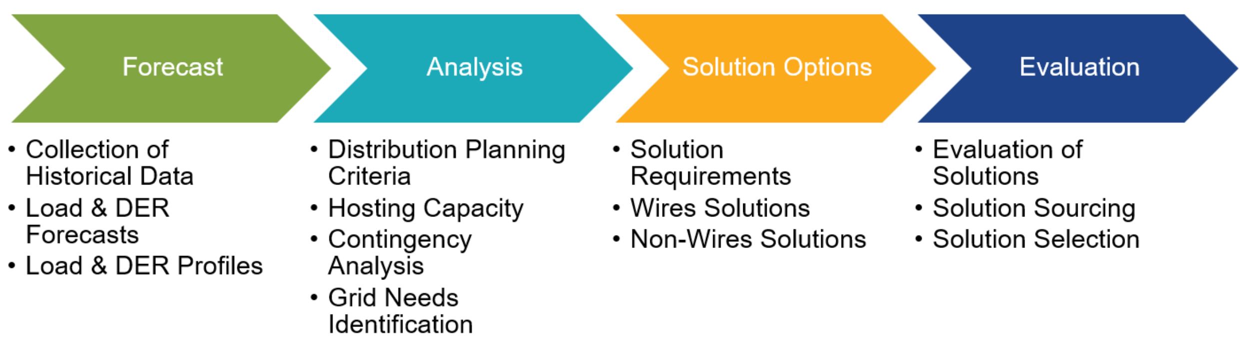


Figure 1: Stages of the Distribution Planning Process

The Distribution Planning Process is incorporated into the IGP process as it uses the corporate forecasts that include planned electrical demand and DER developed through IGP as an input

[1] *See* https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/distribution_planning/20200602_dpwg_distribution_planning_methodology.pdf

[2] Concurrent to this filing, an update to the Distribution Planning Methodology was filed in the Grid Needs Assessment (Nov. 2021, Dkt. No. 2018-0165). References in this document are made to the document in footnote 1.

to the distribution planning analyses to identify distribution grid needs. These distribution grid needs are then used as an input into the IGP process which will select portfolios of solutions to address resource, transmission, and distribution needs. The figure below shows how the Distribution Planning Process (see orange box) is performed in parallel which then converges with other identified steps in the IGP Process.

Figure 2: Distribution Planning Process and IGP Process[3]

This document focuses on describing the Forecast Stage of the Distribution Planning Process. Transformer and circuit location-based forecasts are the result.[4]

1.2 Use of Corporate Forecasts

As part of this analysis, location-based forecasts for the next ten years (year 2021 through 2030)[5] are derived from the corporate forecasts provided in the Hawaiian Electric Revision to Updated and Revised Inputs and Assumptions ("August Update") filed on August 19, 2021.[6]

[3] Hawaiian Electric, Presentation to IGP Stakeholder Technical Working Group, June 17, 2021.

[4] The forecasts are voluminous and therefore not provided in this report in table format. The files are available on the Company website in Excel workbooks. See Appendix A:.

[5] For this report, the Company elected to review the 10-year forecast as opposed to the 5-year forecast as provided in the *Distribution Planning Methodology*, pg. 19.

[6] *See* Hawaiian Electric Revision to Updated and Revised Inputs and Assumptions filed on August 19, 2021 in Docket No 2018-0165.

The corporate forecasts include specific layers for the underlying load growth, distributed energy resources ("DER"), energy efficiency ("EE"), and electric vehicles ("EV")[7]. These layers that are provided at the system level are disaggregated to create a total demand forecast for each circuit and transformer.

As discussed in the August Update, various forecast sensitivities and scenarios were developed to address forecasting uncertainty. As such, three of the scenarios were selected to provide a bookend approach in developing the location-based forecasts. In addition to a base forecast, the High Load Customer Technology Adoption Bookend and the Low Load Customer Technology Adoption Bookend were chosen to understand the impact of customer adoption of technologies that lead to higher loads and lower loads, respectively. The scenarios selected from the August Update are summarized in the following table.[8]

Table 1-1: Forecast Layer Mapping of Modeling Scenarios and Sensitivities

No.	Modeling Case	DER Forecast	EV Forecast	EE Forecast	TOU Load Shape
1	Base	Base Forecast	Base Forecast	Base Forecast	Managed EV Charging
2	High Load Customer Technology Adoption Bookend	Low Forecast	High Forecast	Low Forecast	Unmanaged EV Charging
3	Low Load Customer Technology Adoption Bookend	High Forecast	Low Forecast	High Forecast	Managed EV Charging

[7] This analysis uses the forecast for light duty electric vehicles but does not consider the forecast for eBus.

[8] *See* Hawaiian Electric Revision to Updated and Revised Inputs and Assumptions filed on August 19, 2021 in Docket No 2018-0165. Table 6-3.

2 Deriving Location-Based Forecasts

This section describes the steps used to derive the location-based forecasts:

1. Compile a base load shape for each circuit.
2. Add specific DER and load growth adjustments.
3. Determine corporate forecast layer amounts to be allocated.
4. Perform location-based allocation.

First, a base load shape is compiled using a historical load shape for each circuit and serves as the base for creating the location-based forecasts. The raw data is reviewed to remove anomalous data that is not representative of normal feeder conditions such as loss of load due to planned maintenance or system interruptions on the feeders.

In step 2, known future load growth and DER in specific areas, such as service requests and CBRE phase 1 projects, are added to the circuits where the growth is anticipated. Within the LoadSEER software this is known as "adjustments". In step 3, the corporate forecast layers are adjusted, if necessary, to determine the total forecast amounts for each layer that will be allocated amongst each circuit.

Steps 2 and 3 determine the total amount of load that will be allocated to each circuit in step 4 to create the location-based forecasts. The process is different for O'ahu and the neighbor islands. As mentioned in the August Update, LoadSEER is currently being used to develop location-based forecasts for O'ahu. Step 2 and step 3 prepare the load for input into LoadSEER and step 4 is completed using the LoadSEER program. Since LoadSEER modeling is not yet available for Maui County and Hawai'i Island[9], a different method is used to perform steps 2 through 4.

In summary, the location-based allocation in step 4 is performed using one of the following methods for the respective islands:

1. Forecast allocation in LoadSEER (O'ahu)
2. Forecast allocation based on existing loads (Hawai'i Island and Maui County)

The steps are summarized in the figure below.

[9] The implementation of LoadSEER for the neighbor islands is targeted for middle of 2022 as reported in Exhibit 2 of Hawaiian Electric Companies' Quarterly DER Technical Report filed on September 30, 2021 in Docket No. 2019-0323.

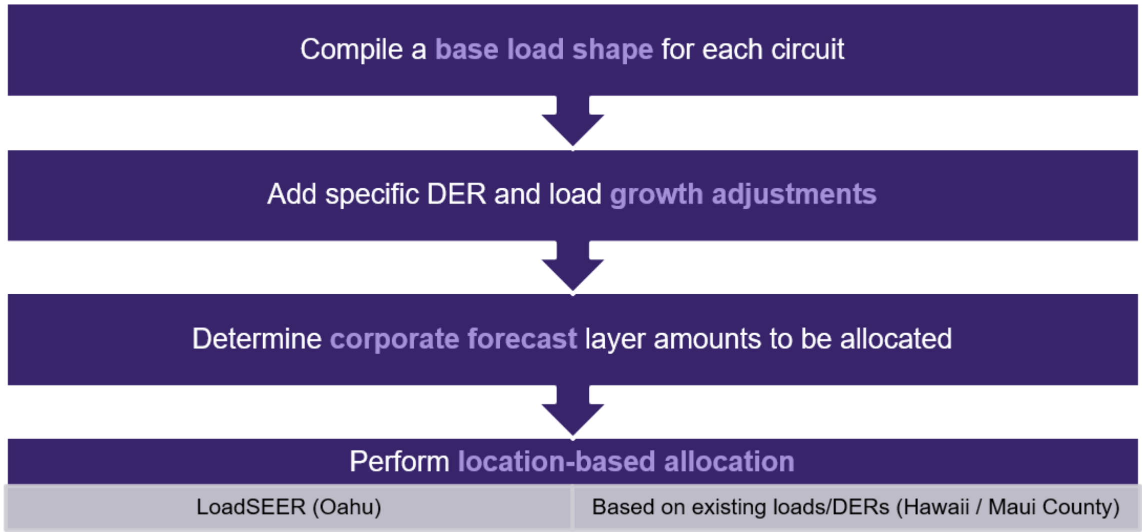


Figure 3: Steps to Derive Location-Based Forecasts

Consistent with the *Distribution Planning Methodology*, the resulting location-based forecasts will be provided in the following format:[10]

- Demand Forecast
- Demand Forecast by Load Type

The resulting location-based forecasts are discussed further in Section 3 and available on the Company website (see Appendix A: for a description of the files provided).

The following procedures described in this section are repeated for each scenario and its corresponding sensitivity layers:

- Base
- High Load Customer Technology Adoption Bookend
- Low Load Customer Technology Adoption Bookend

[10] Hawaiian Electric, *Distribution Planning Methodology*, June 2020 at 19.

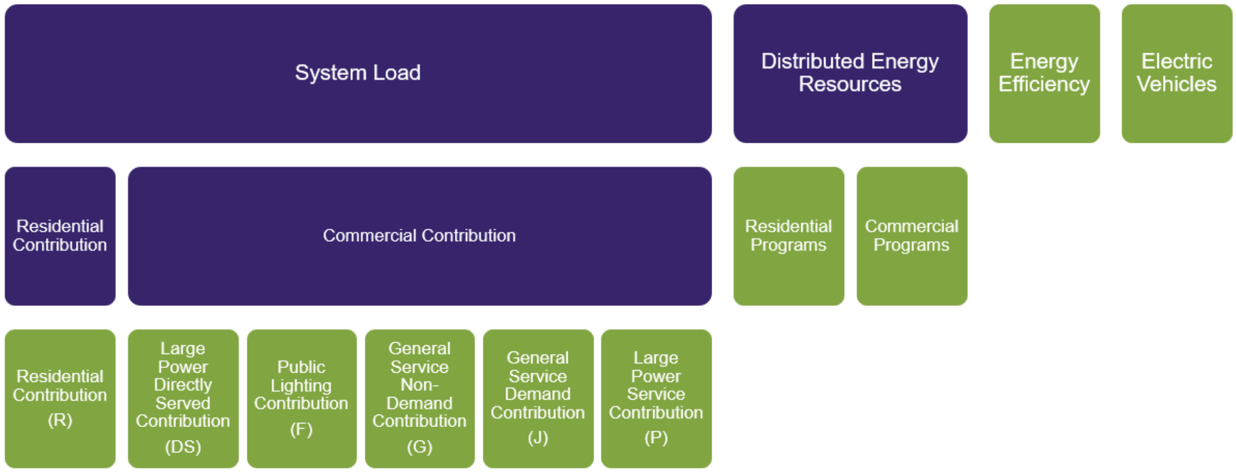


Figure 4: Illustration of forecast allocation by layers (top row indicates disaggregated layers)

2.1 BASE LOAD SHAPE

The base load shape is created using historical load data and serves as the basis for creating the location-based forecasts. Historical load data for the prior calendar year is compiled for each circuit in hourly ("8760") format.[11] For this process, historical load data from the year 2020 was compiled.[12] This data is compiled primarily using raw data sources such as distribution supervisory control and data acquisition ("SCADA") devices that measure load at the distribution transformer or circuit level.

Since the raw data contains measured data for all hours of the year, the raw data is reviewed to remove anomalous data that is not representative of normal feeder conditions such as loss of load due to planned maintenance or system interruptions on that feeder or conversely, extra load on the feeder due to transferred load from an adjacent feeder. In addition to these types of events, there may also be missing or bad data due to a loss of communication with the SCADA devices.

For O'ahu, the historical load data is analyzed in SCADA Scrubber. As described in the *Distribution Planning Methodology*, SCADA Scrubber[13] is a tool available in LoadSEER that analyzes hourly data for trends then normalizes periods where there are system interruptions or planned maintenance. Once the data is processed using SCADA Scrubber, the resulting "cleaned" shape is considered the normal feeder load and used in the subsequent processes. The following figure shows an example of a circuit shape being "cleaned". The red line plot in

[11] An 8760-hour profile represents all 365 days of the year at a 1-hour resolution.

[12] Data for year 2020 was used to calculate the historical circuit peaks. For circuits where this data was unavailable, data for the most recent historical year was used or the circuit peak was estimated based on a similar circuit.

[13] Hawaiian Electric, *Distribution Planning Methodology,* June 2020 at 8-9.

the upper chart is the original SCADA data that contains anomalous portions. The blue plot is the resulting "cleaned" data where the anomalous sections were removed using SCADA Scrubber.

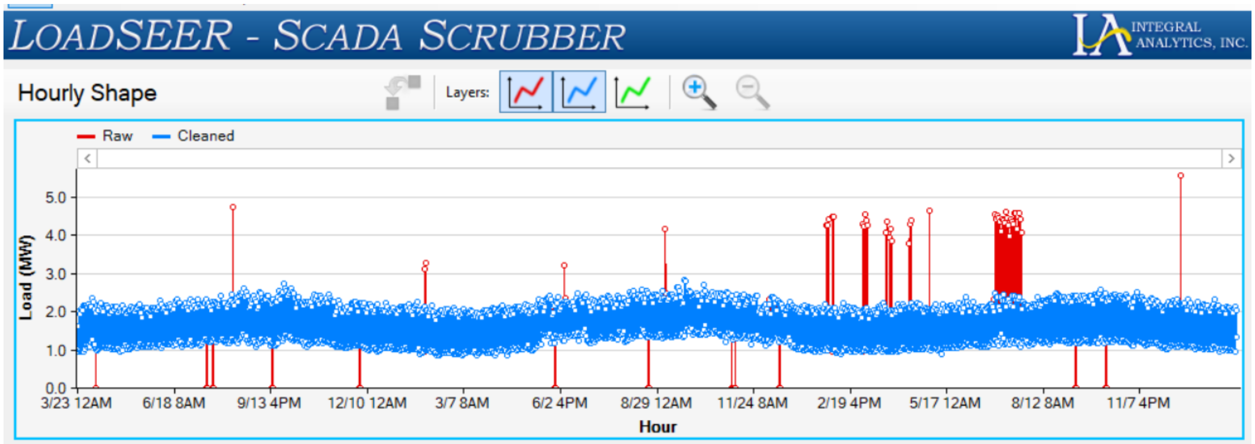


Figure 5: Hourly data for a Sample Circuit Processed in SCADA Scrubber (Red-Raw Data, Blue-Clean Data)

For Hawai'i Island and Maui County, the 2020 SCADA data was analyzed manually to determine the circuit peak loads. Anomalous periods of data are excluded when determining the peak load. The following figure shows example SCADA data for the single phase feeder readings in megawatts ("MW") showing an anomalous peak. In general, the anomalous peaks are verified against actual operations on the day that it occurred (i.e., planned maintenance, system interruptions, etc.). This peak was excluded when determining the circuit peak load to use for the base load shape for this circuit, similar to the way SCADA Scrubber cleans the SCADA data.

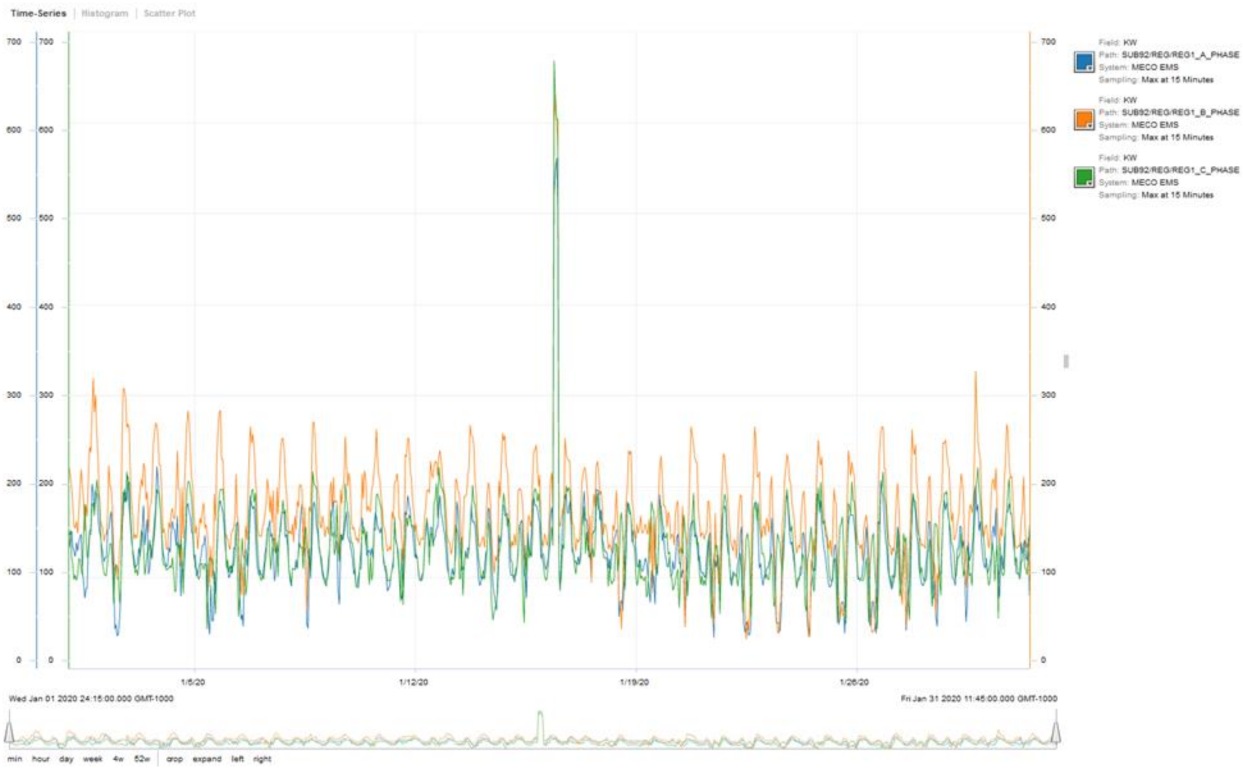


Figure 6: Sample SCADA Data with an Anomalous Peak

2.2 LOAD GROWTH ADJUSTMENTS

The Company receives service requests, or new load requests, from residential and commercial developers such as new subdivisions, condominiums, or shopping centers throughout the year as part of the normal Distribution Planning process. Typically when these requests are received, the developer provides an estimated peak load and an approximate in-service date.

Since service requests are for anticipated new loads in specific areas, the capacities of nearby feeders are evaluated and the service is assigned to a feeder based on location and available feeder capacity. This process is also described in the *Distribution Planning Methodology*.[14] The total load anticipated due to service requests are summed by feeder.

<u>O'ahu (Preparation for Allocation in LoadSEER)</u>

In LoadSEER, these service requests are added to the forecast as map adjustments. Map adjustments in LoadSEER can be either load or generation adjustments to the forecast where the location is known and can be added directly to the map tool in LoadSEER. The following is

[14] Hawaiian Electric, *Distribution Planning Methodology*, June 2020 at 9.

a screenshot of the map tool in the LoadSEER program. Since the service locations and the specified demand amounts are provided by customers on the service requests, the new service can be added at their specific locations.

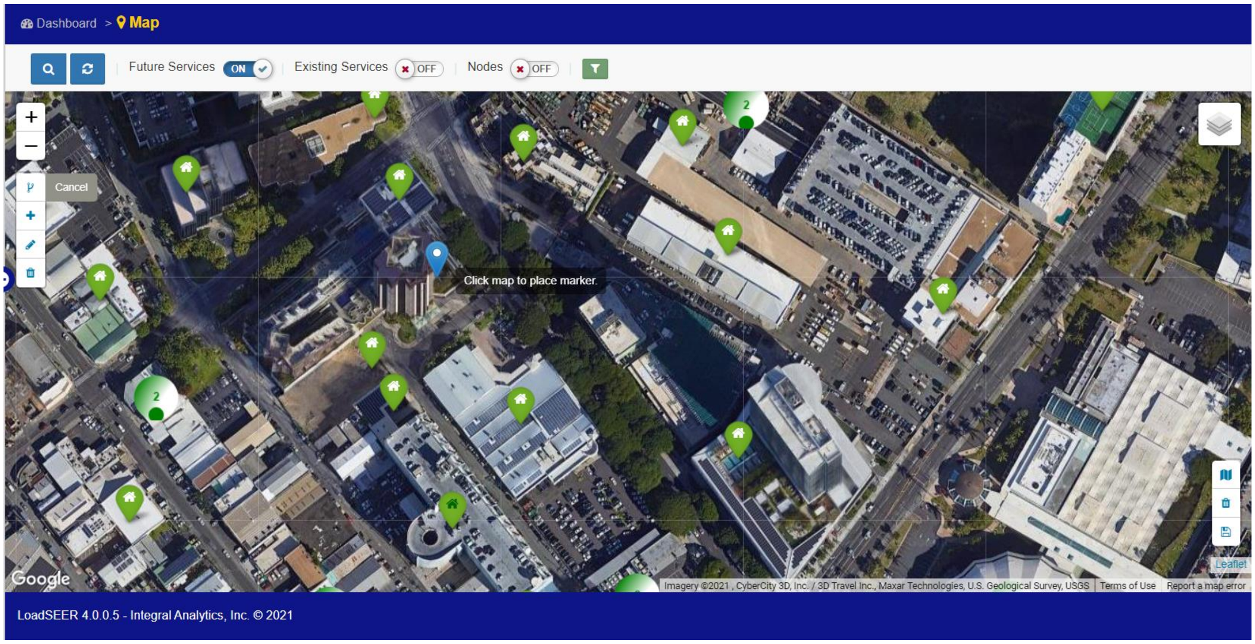


Figure 7: LoadSEER Map

These service requests are assigned to a nearby distribution feeder with available capacity and are then "locked" into the final forecast as a separate growth category, in addition to the forecast layers that will be described in the following sections.

These totals are shown as New Service Requests.

<u>Hawaiʻi Island and Maui County (Preparation for Allocation Based on Existing Load)</u>

Since the service requests are for anticipated loads in specific areas, the service requests received are summed by circuit to create a total service request amount (MW). This amount will be assigned to specific circuits where the future load growth is anticipated. For the purposes of this analysis, if an estimated in-service date was not provided by the customer, it is assumed that the loads will be in-service in the year 2025 timeframe. The year 2025 was chosen as an estimate using the middle of the study period.

The service request totals are combined with the underlying load from the corporate forecast (see Section 2.3.1) to create the forecasted load growth (see Section 2.4.2.2.).

2.3 CORPORATE FORECAST

As described in the August Update, modeling scenarios and sensitivities were developed to test different customer behaviors and changes in policy by incorporating a range of corporate forecasts. The scenarios and sensitivities provide a range of possible futures based on different levels of technology adoption rates. The corporate forecasts are created at the system level and are built with layers that include the underlying load, DER, EV, and EE components.

The August Update provided the corporate forecast layers as a load on an hourly basis (8760) for years 2021 through 2050.[15] These 8760 profiles are used to determine the amount of load for each layer that will be allocated as explained in Section 0. The process to determine the corporate forecast amounts to be allocated for each layer are described in the following sections.

2.3.1 Underlying Load

<u>O‘ahu (Preparation for Allocation in LoadSEER)</u>

Starting with the Underlying Load Forecast 8760[16] from the August Update, the monthly peak is extracted for each year from 2021 through 2030. The extracted monthly peak for each year will be used to create the LoadSEER input files that relate the Corporate level forecast to the circuit level spatial allocation. The figure below shows one month of hourly data from the August Update Workbook 3. In this example, the peak value 1,094 MW is extracted for the month of January.

[15] Revised Input and Assumption workbooks for the August Update are available on the Company's website: https://www.hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning/stakeholder-engagement/key-stakeholder-documents..

[16] *See*: https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/Revised%202021-08-18%20Draft%20Oahu%20Inputs%20Workbook%203.xlsx.

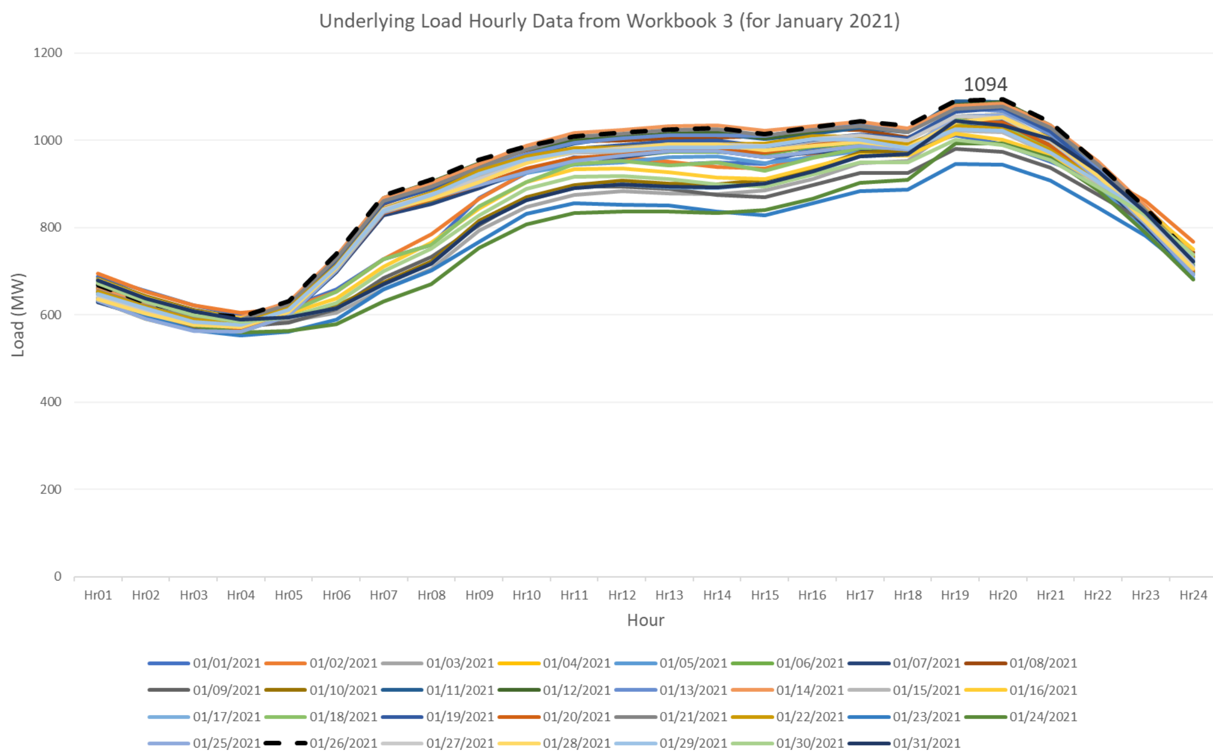


Figure 8: Underlying Load Hourly Data from Workbook 3 (for January 2021)

Once the monthly peaks for the entire forecast period are determined, the monthly incremental change is calculated. For the underlying load forecast, the monthly incremental total is then split into customer rate classes based on historical load data and allocated to the distribution circuits based on their respective totals. The following figure shows the customer rate classes created through the disaggregation of the system load.

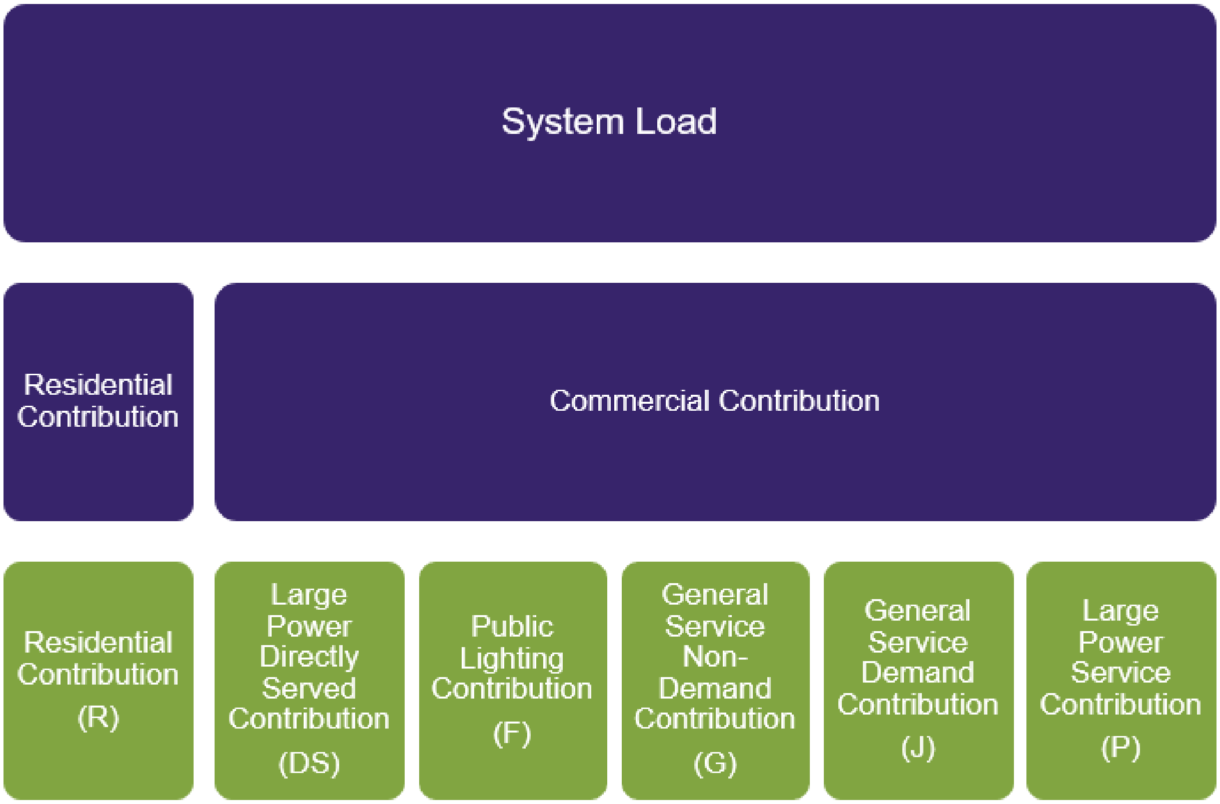


Figure 9: System Load Disaggregation into Customer Rate Classes

In order to minimize double counting service requests that may already be accounted for in the corporate forecast, the amount specified in the input files for the underlying load are reduced by the LoadSEER program based on the map adjustments described in Section 2.2.

Hawai'i Island and Maui County (Preparation for Allocation Based on Existing Load)

Similar to the process described for LoadSEER preparation, the monthly peak is extracted for each year from 2021 through 2030 using the Underlying Load Forecast 8760 from Workbook 3 of the August Update. An additional step is then needed to adjust the underlying load for load growth anticipated in specific areas. As described in Section 2.2, the Company receives service requests for anticipated loads in specific areas. The underlying load to be allocated is reduced by the total amount (MW) of service requests to avoid double counting load to be allocated. This amount is then allocated amongst the circuits as described in Section 2.4.2.1.

2.3.2 Distributed Energy Resources

The DER forecast layers provided in Workbook 3 of the August Update consist of separate layers for DGPV and DBESS by rate class. The following 8760 load profiles from the corporate forecasts serve as the starting point to determine the total DGPV and DBESS amounts to be allocated:

- DGPV[17]
- DBESS Residential (Schedule-R)
- DBESS Small Commercial (Schedule-G)
- DBESS Medium Commercial (Schedule-J)
- DBESS Large Commercial (Schedule-P)

In addition, the corporate DER and BESS forecast includes a monthly capacity (kW) forecast by rate class (e.g., Schedule-R, Schedule-G, Schedule-J, and Schedule-P) for the forecast period.

<u>O‘ahu (Preparation for Allocation in LoadSEER)</u>

Starting with the DER and DBESS monthly capacity forecast, the incremental amount of DER added in each month is determined for years 2021 through 2030 for each rate class. These incremental amounts are then used to create input files used by LoadSEER for each rate class. This process is repeated to create input files for both DGPV and DBESS for each rate schedule:

- DGPV (Schedule-R)
- DGPV (Schedule-G)
- DGPV (Schedule-J)
- DGPV (Schedule-P)
- DBESS (Schedule-R)
- DBESS (Schedule-G)
- DBESS (Schedule-J)
- DBESS (Schedule-P)

An additional LoadSEER input file is also created for the CBRE Phase 2 small projects program capacity on O‘ahu to be account for the 30 MW small project capacity described in the latest Order.[18] This LoadSEER input file allocates the 30 MW evenly across each month for 5 years (year 2021 through 2025).

The LoadSEER program requires an 8760 or 576 load shape/profile for each layer in the forecast. In some cases, there are no existing or default load shapes, as in the case for DBESS, EE, or EV layers. To address this, the 8760 corporate load forecast for the DBESS in Workbook 3 is used to create an average load shape for each rate class. To do this, the average hourly load

[17] DGPV layer includes impacts of behind the meter PV.

[18] *See* Order No. 37879 issued on July 27, 2021 in Docket No. 2015-0389, Approving the March 30 CBRE Filings, with Modifications.

shape for the final year of the forecast period (2030) is used to create a normalized 8760 load shape that can be imported into the LoadSEER program. These load profiles are scaled by LoadSEER at the individual service points where the DBESS (or other asset such as DGPV, EE, etc.) is allocated throughout the system when creating the circuit level forecast. The following figures show sample average DBESS load shapes for different customer rate schedules under the Base scenario for the study period.

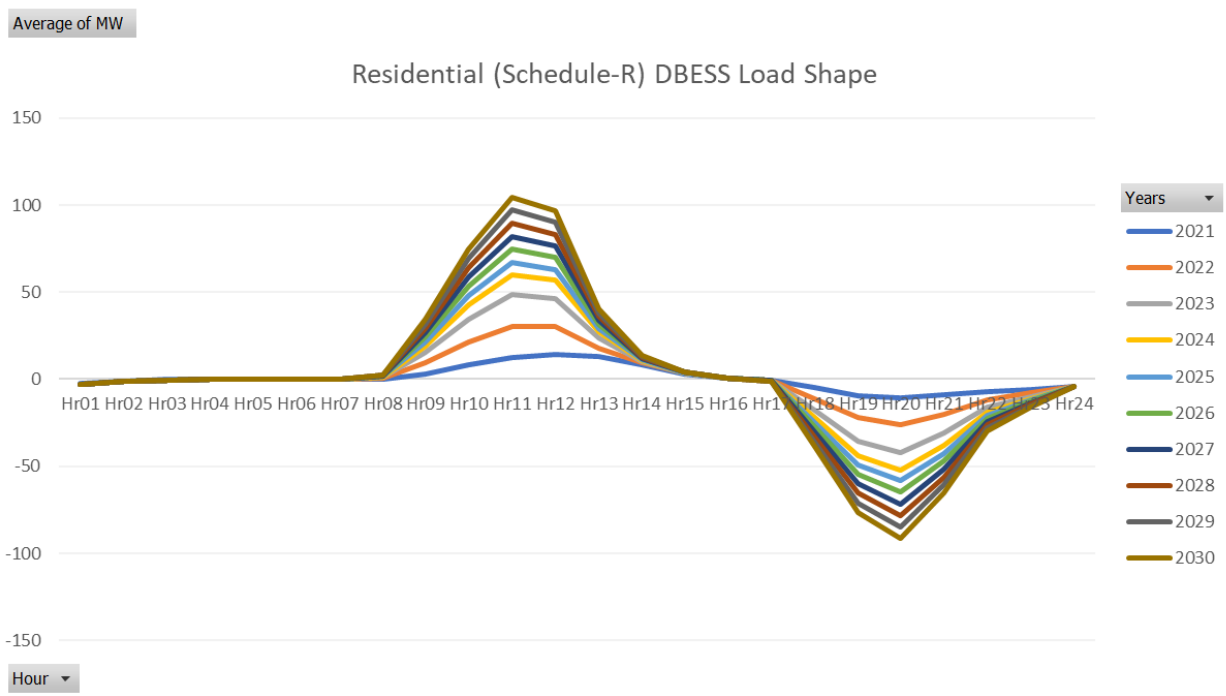


Figure 10: Residential (Schedule-R) DBESS Load Shape - Base Scenario

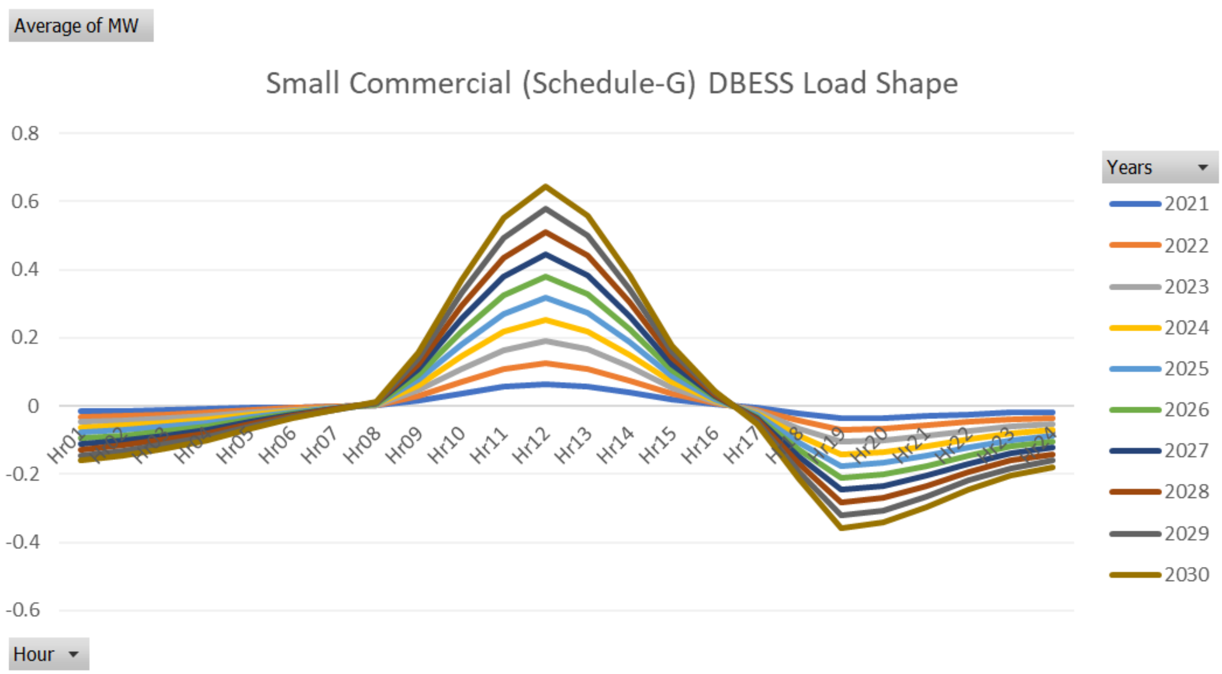


Figure 11: Small Commercial (Schedule-G) DBESS Load Shape - Base Scenario

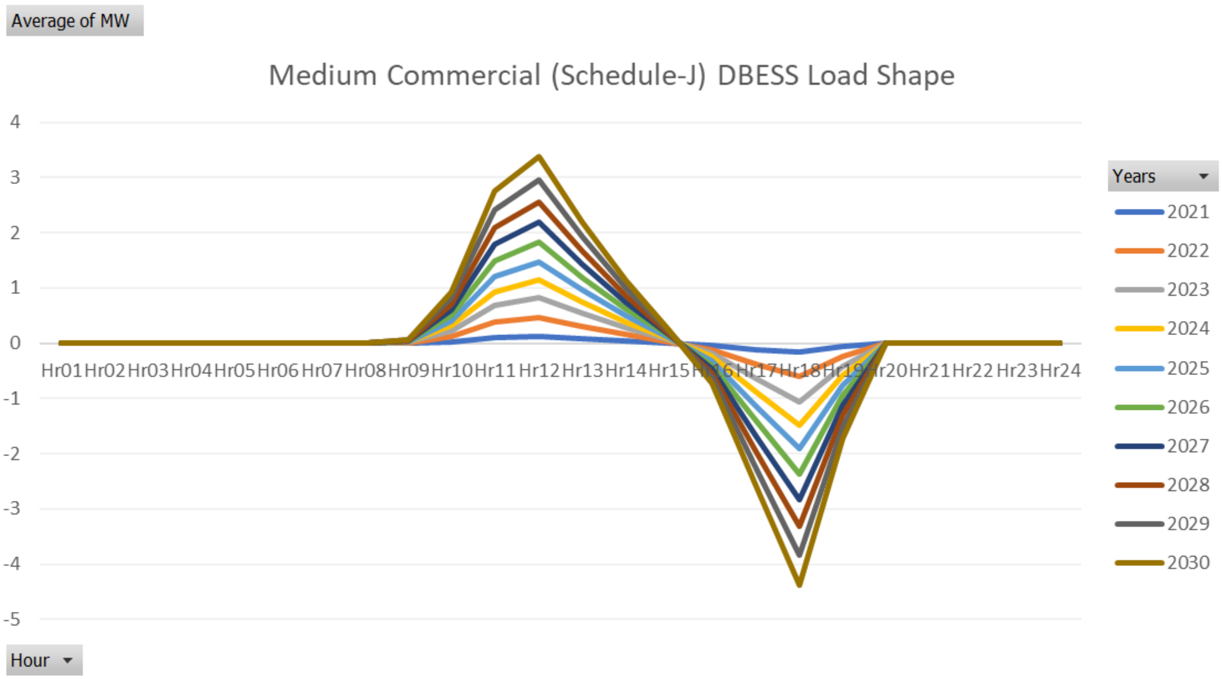


Figure 12: Medium Commercial (Schedule-J) DBESS Load Shape – Base Scenario

Hawai'i Island and Maui County (Preparation for Allocation Based on Existing DGPV)

The process to determine the DGPV allocation amount is consistent with the methodology used to determine the DER forecast allocation based on existing DER described in the *Distribution DER Hosting Capacity Grid Needs* document provided in the August Update.[19,20] An annual incremental amount is determined from the DER capacity forecast then adjusted by adding the CBRE Phase 2 small projects program. This sum is then allocated amongst the circuits using the process described in Section 2.4.2.2. Similar to the process described for LoadSEER preparation, the BESS capacity forecast is used to determine the incremental amount of DBESS added in each year for years 2021 through 2030. This incremental amount is then allocated amongst the circuits using the process described in Section 2.4.2.2.

[19] *See* https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/20210803_heco_submittal_of_igp_inputs_and_assum_and_der_hosting_capacity.pdf

[20] This is also consistent with the methodology described in the *Distribution DER Hosting Capacity Grid Needs November 2021 Update* filed concurrently with this report (Nov. 2021, Dkt. No. 2018-0165).

2.3.3 Electric Vehicle

O'ahu (Preparation for Allocation in LoadSEER)

Starting with the EV-Managed Base Forecast from Workbook 3 of the August Update, the monthly peaks are extracted from the 8760 data. Those peak values are used to create the LoadSEER input file which relates the Corporate level forecast to the circuit level spatial allocation. After the allocation, circuit level forecasts can be computed for the EV layer.

The same process is used to create the LoadSEER input files for the EV-Managed Low Forecast and EV-Unmanaged High Forecast from Workbook 4 of the August Update.

Similar to the DBESS layer, the 8760 data from Workbook 3 is also used to create an average load shape that is imported into the LoadSEER program. The same Managed adjustment shape was used for both Base and Low scenarios. A separate load shape was created and imported for the Unmanaged high scenario.

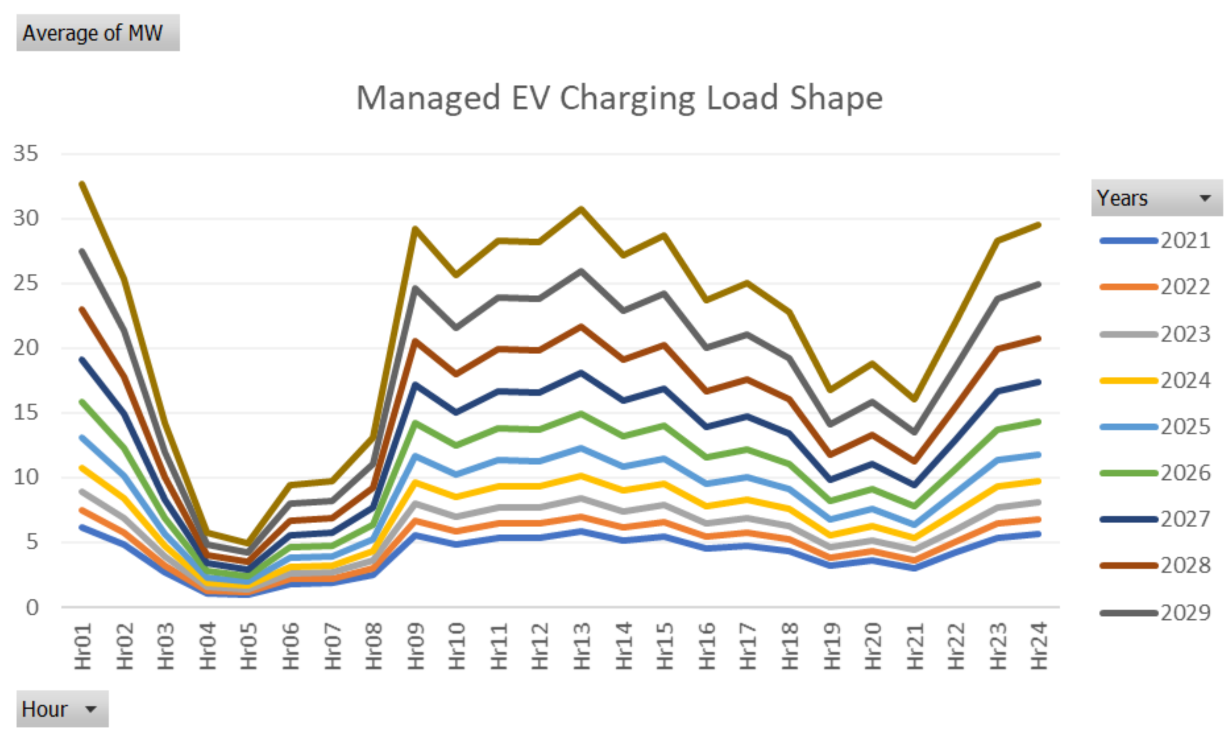


Figure 13: Managed EV Charging Load Shape

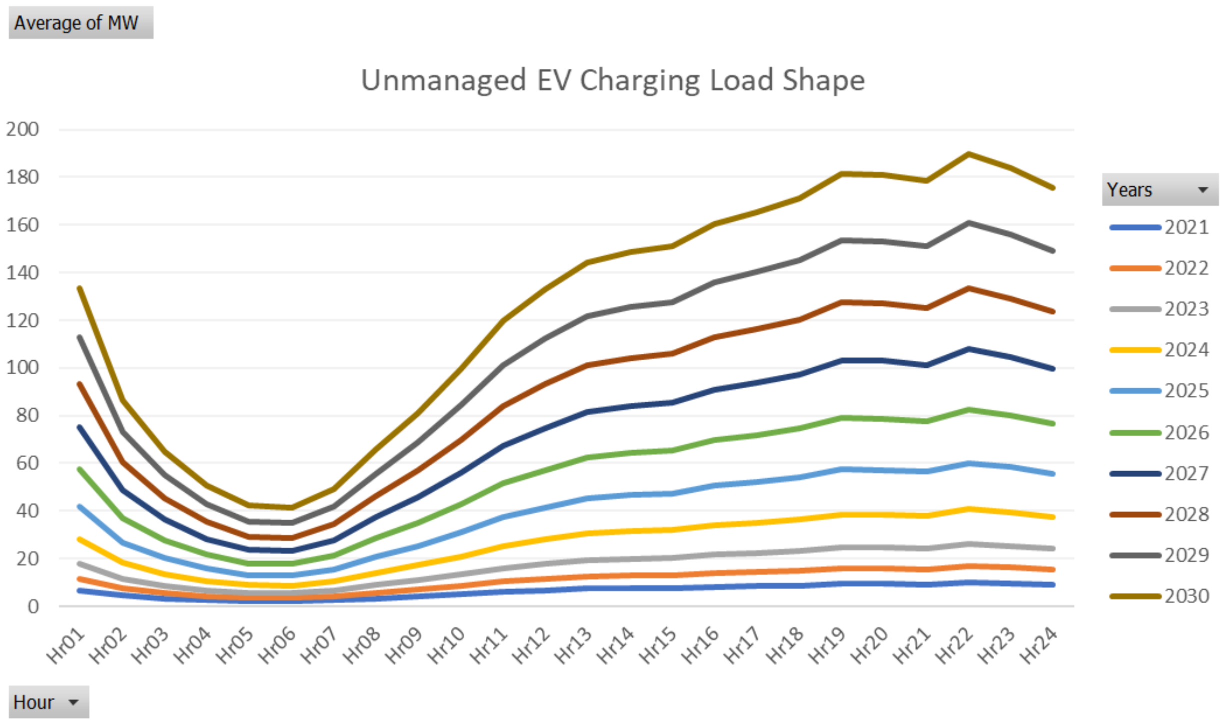


Figure 14: Unmanaged EV Charging Load Shape

<u>Hawai'i Island and Maui County (Preparation for Allocation Based on Existing Load)</u>

Similar to the process described for LoadSEER preparation, the monthly peaks are extracted for each year from 2021 through 2030 using the Managed EV – Base Forecast from Workbook 3 of the August Update for the Base Modeling Case. The same process is used to determine the allocation amounts for the Managed EV – Low Forecast and the Unmanaged EV – High Forecast from Workbook 4 of the August Update. This amount is then allocated amongst the circuits as described in Section 2.4.2.3.

2.3.4 Energy Efficiency

<u>O'ahu (Preparation for Allocation in LoadSEER)</u>

Starting with the EE-Base Forecast from Workbook 3 of the August Update, the monthly minimum (which provides the largest energy reduction) is extracted from the 8760 data. The minimums (or largest load reductions) are used to create the LoadSEER input file which relates the corporate level forecast to the circuit level spatial allocation. After the allocation, circuit level forecasts can be computed for the EE layer.

The same process is used to create the LoadSEER input files for the EE-High Forecast and EE-Low Forecast from Workbook 4 of the August Update.

Similar to the DBESS and EV layers, the 8760 data from Workbook 3 and 4 is used to create an average load shape that is imported into the LoadSEER program as described previously in Section 2.3.2. However, for the EE layer, separate load shapes were imported and used for the 3 scenarios: Base, Low, and High.

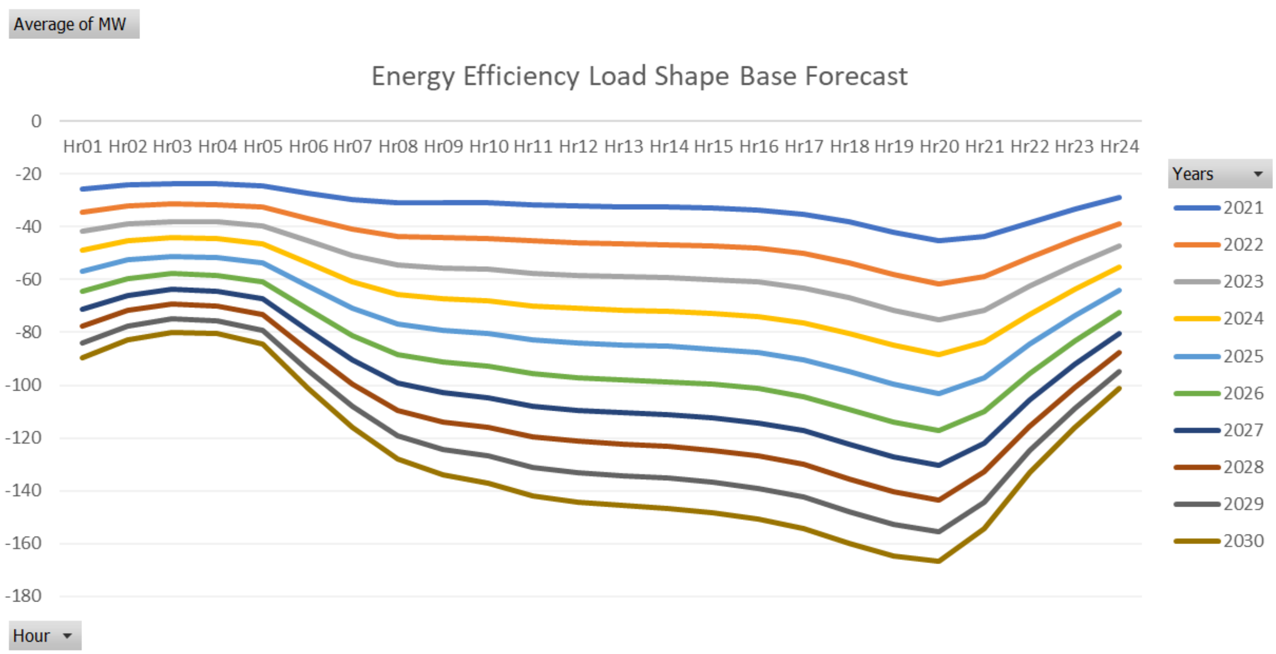


Figure 15: Energy Efficiency Load Shape – Base Forecast

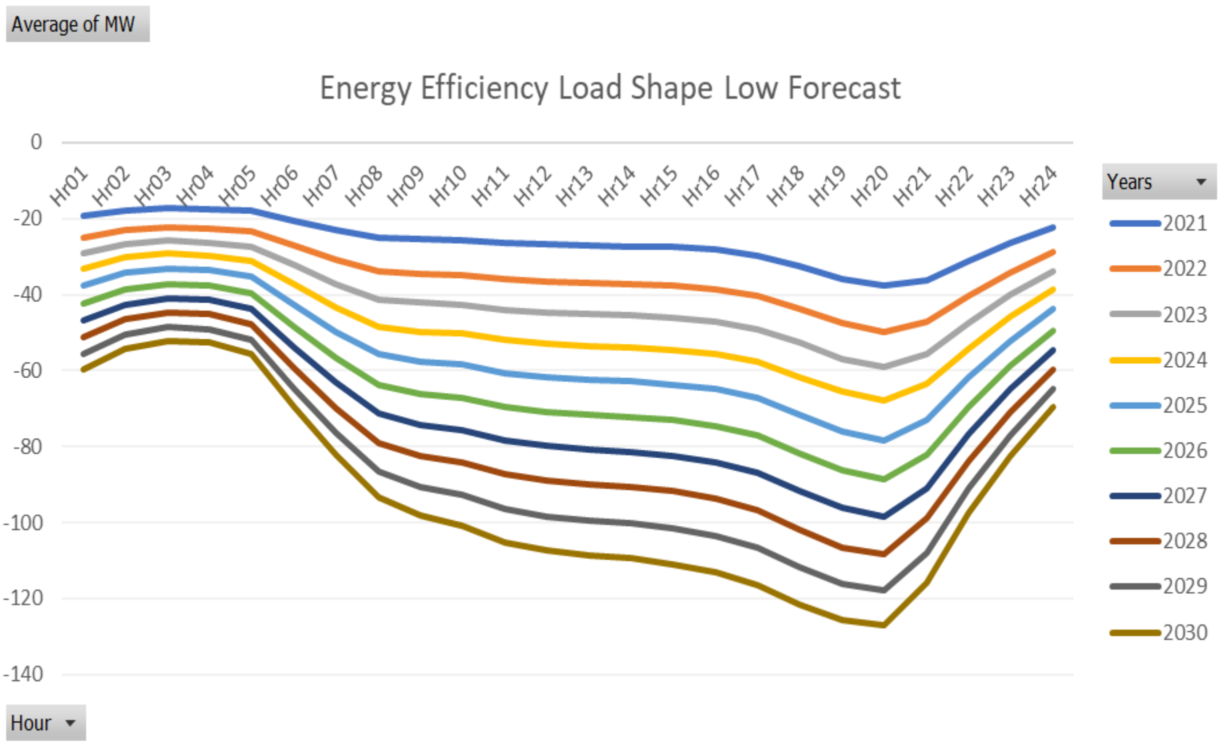


Figure 16: Energy Efficiency Load Shape – Low Forecast

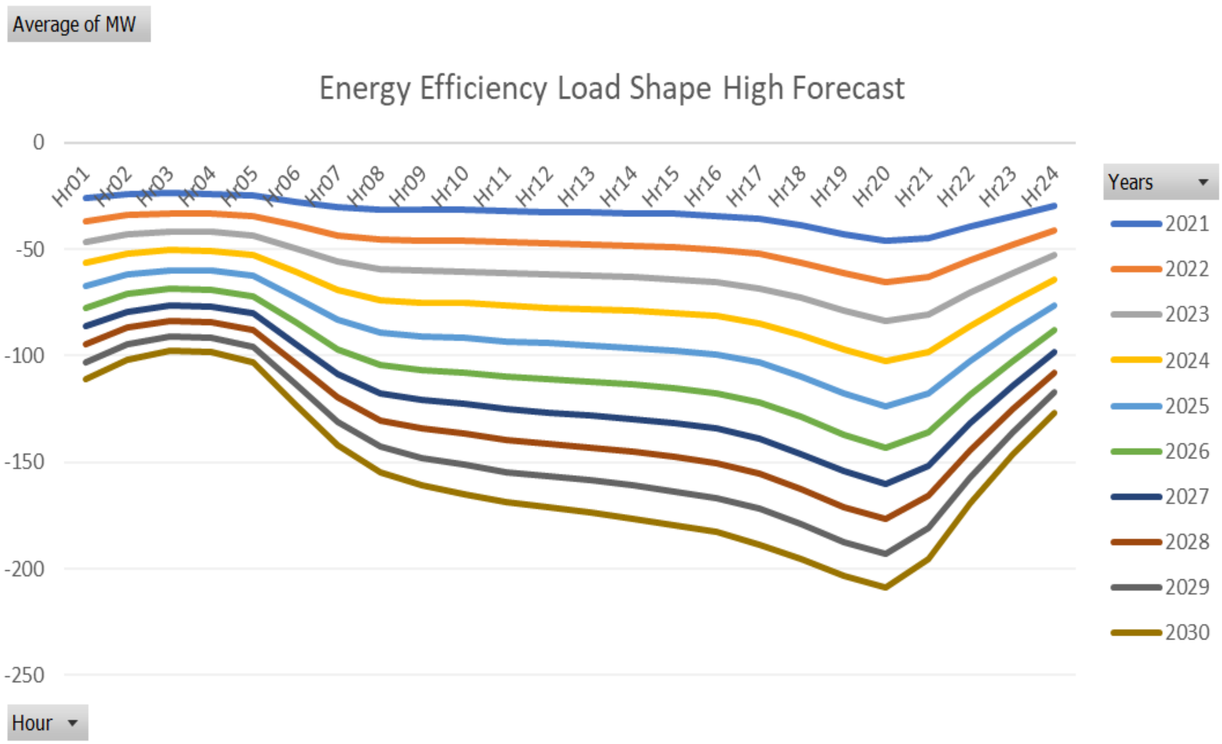


Figure 17: Energy Efficiency Load Shape – High Forecast

<u>Hawai'i Island and Maui County (Preparation for Allocation Based on Existing Load)</u>

Similar to the process described for LoadSEER preparation, the monthly minimum (which provides the largest energy reduction or similarly, the largest load reduction) is extracted for each year from 2021 through 2030 using the EE – Base Forecast from Workbook 3 of the August Update. The same process is used to determine the allocation amounts for the EE – Low Forecast and the EE – High Forecast from Workbook 4 of the August Update. This amount is then allocated amongst the circuits as described in Section 2.4.2.4.

2.4 LOCATION-BASED ALLOCATION

Once the total forecasted amounts (MW) to be allocated for each layer are determined, the following processes are used to perform the load allocation amongst circuits.

2.4.1 Forecast Allocation in LoadSEER

The forecast allocation is performed in LoadSEER for O'ahu.

2.4.1.1 Scenario 1 – Base

The following average daily hourly load profiles for a sample circuit in the Base scenario are shown in the figure below for comparison:

- Underlying Load
- DGPV and DBESS Base Forecast
- Managed EV Base Forecast
- Energy Efficiency Base Forecast

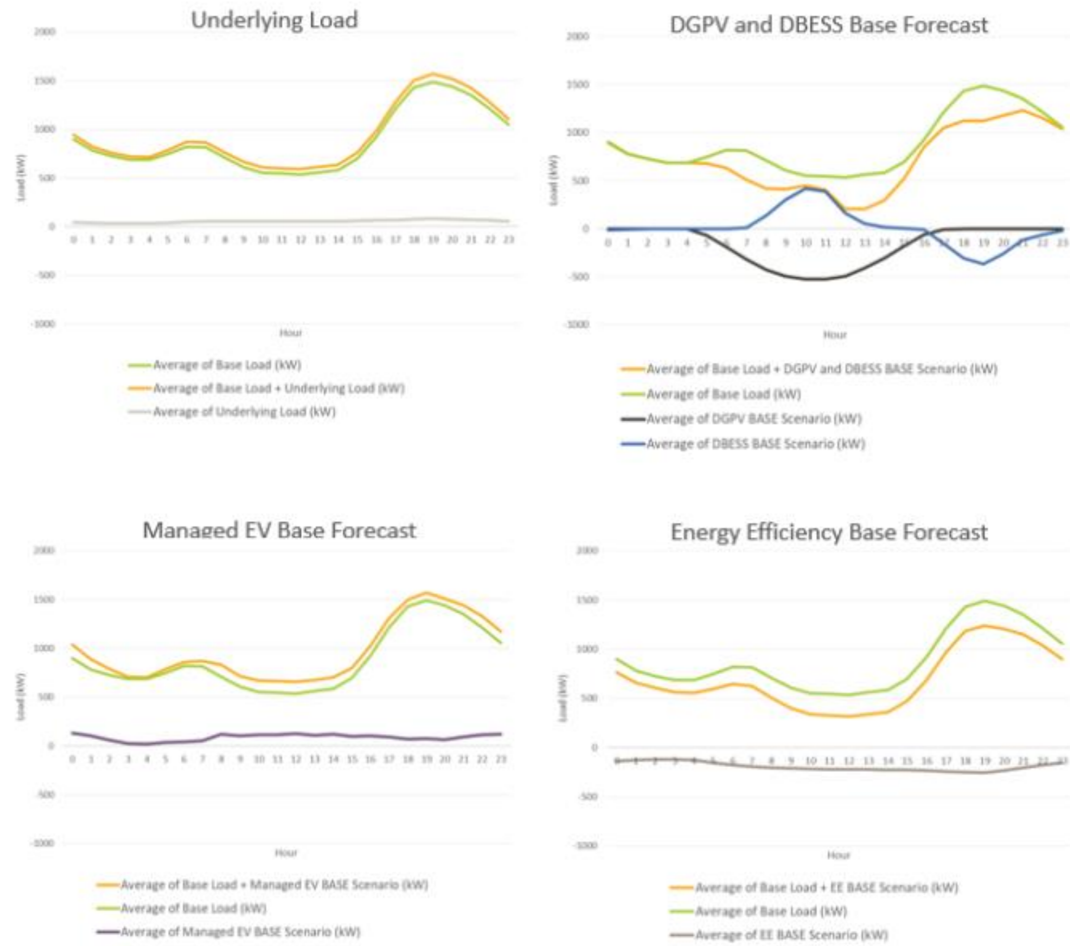


Figure 18: Scenario 1 Average Daily Hourly Load Profiles by Layer (Underlying Load, DGPV and BESS, EV, and EE) for Sample Circuit

The following figures display the same information as the previous figures, but with emphasis on the effect of the aggregated (or stacked) load layers that results in the average shape by layer.

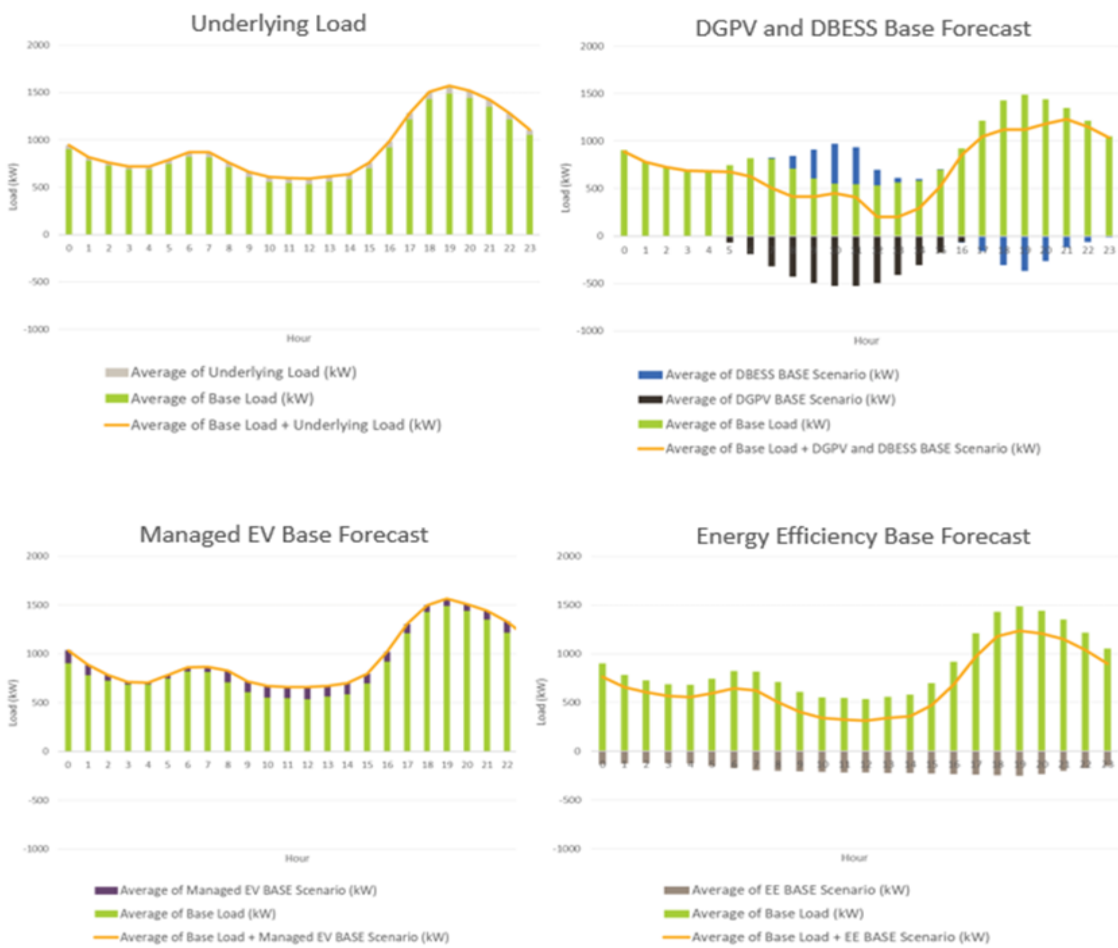


Figure 19: Scenario 1 Average Daily Hourly Load Profiles by Layer (Underlying Load, DGPV and BESS, EV, and EE) with Stacked Load for Sample Circuit

Scenario 1 - Total Forecast

The following chart shows the average base load and average forecasted load for the Base Scenario. For this circuit the average forecasted load decreases due to the impact of the forecasted layers in this scenario.

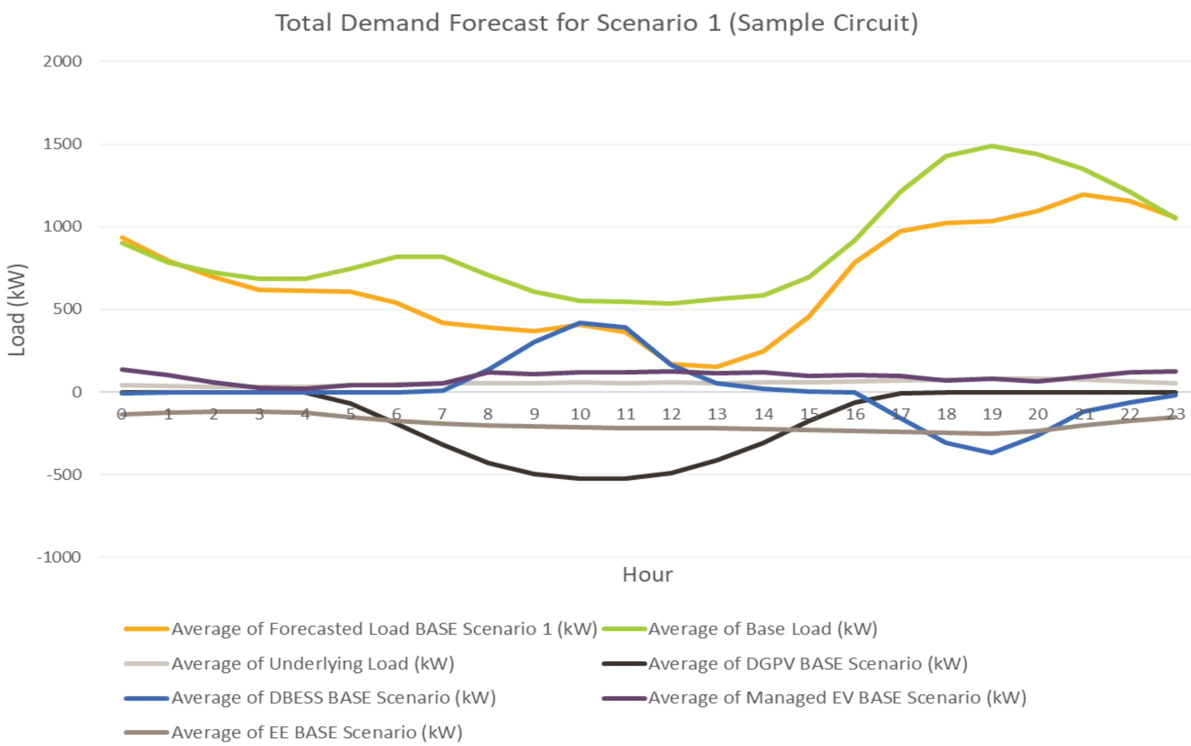


Figure 20: Total Demand Forecast for Scenario 1 (Sample Circuit)

The following figure displays the same information as the previous figure but emphasizes the contribution of the forecast layers on the forecasted load shape.

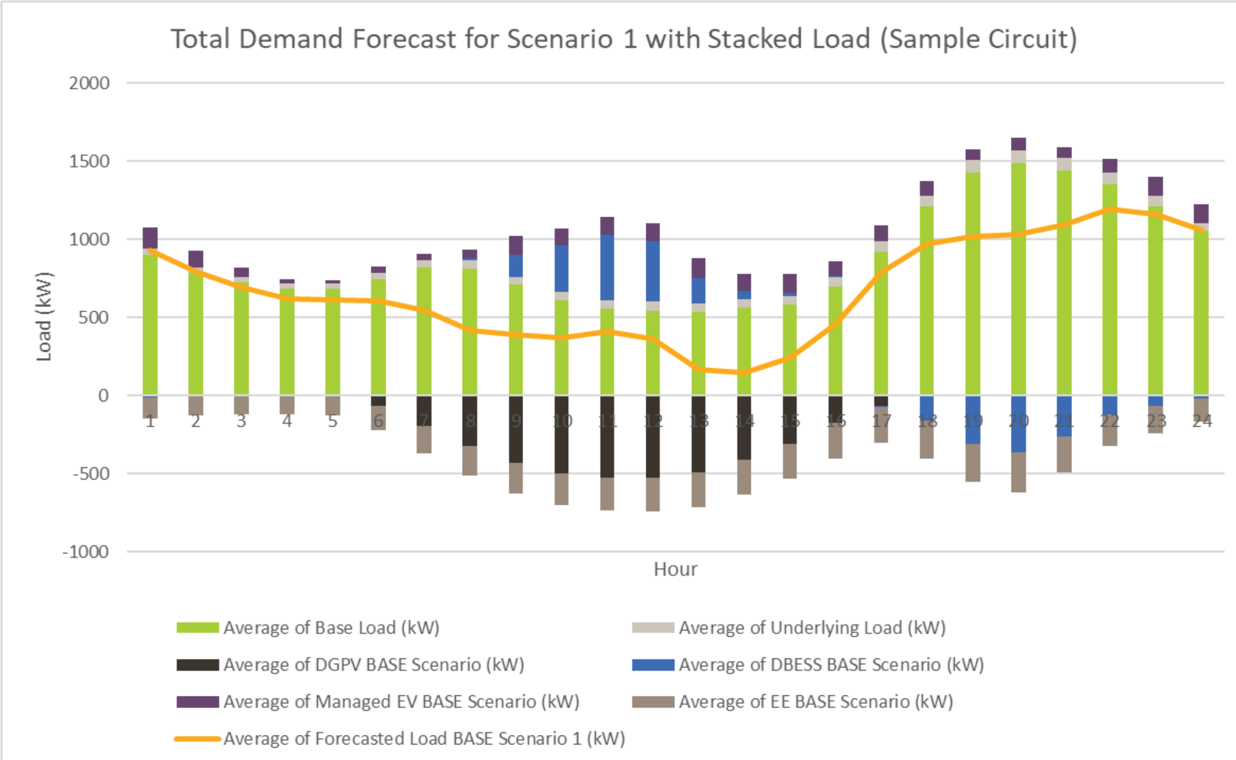


Figure 21: Total Demand Forecast for Scenario 1 with Stacked Load (Sample Circuit)

This process of computing the forecast is repeated for Scenario 2 - High Load Customer Technology Adoption Bookend and Scenario 3 - Low Load Customer Technology Adoption Bookend with the appropriate layers selected for each.

2.4.1.2 Scenario 2 – High Load Customer Technology Adoption Bookend

The following average daily hourly load profiles for a sample circuit in Scenario 2, the High Load Customer Technology Adoption Bookend scenario, are shown in the figure below for comparison:

- Underlying Load
- DGPV and DBESS Low Forecast
- Unmanaged EV High Forecast
- Energy Efficiency Low Forecast

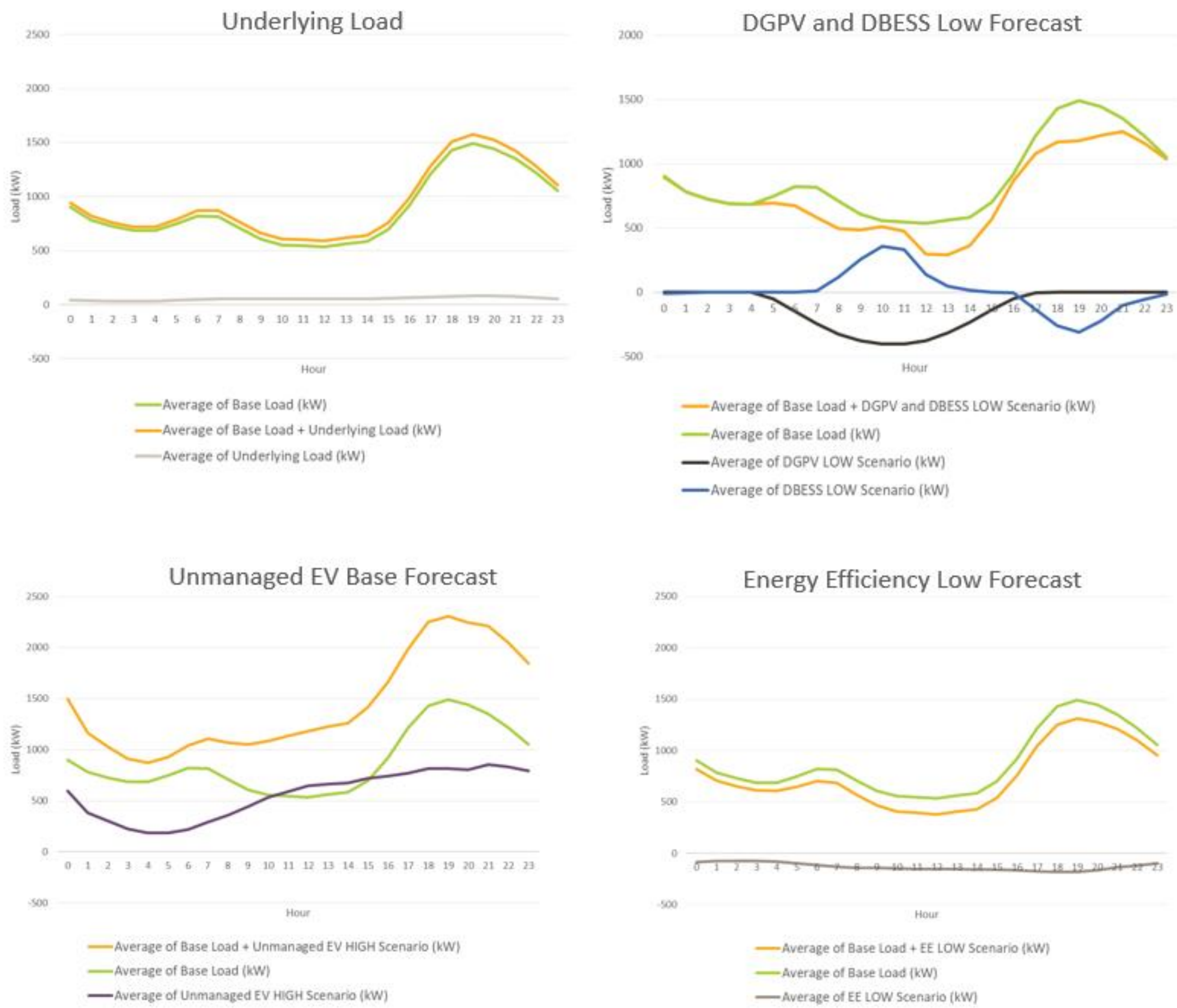


Figure 22: Scenario 2 Average Daily Hourly Load Profiles by Layer (Underlying Load, DGPV and BESS, EV, and EE) for Sample Circuit

As shown for Scenario 1 in the previous section, the following figures display the same information as the above figures, but with emphasis on the effect of the aggregated (or stacked) load layers that results in the average shape by layer.

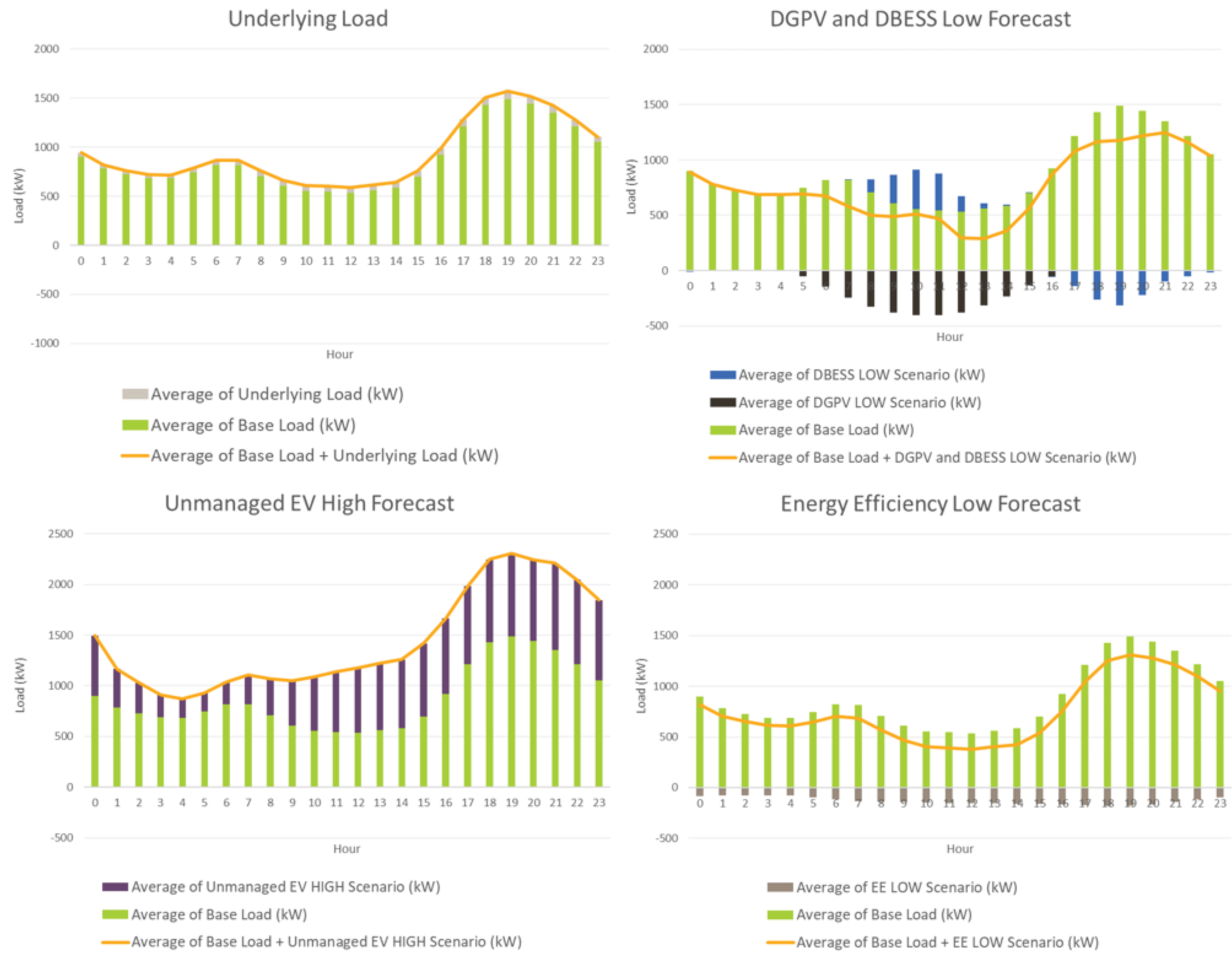


Figure 23: Scenario 2 Average Daily Hourly Load Profiles by Layer (Underlying Load, DGPV and BESS, EV, and EE) with Stacked Load for Sample Circuit

Scenario 2 – Total Forecast

This chart shows the average base load and average forecasted load for the High Load Technology Adoption Bookend Scenario. For this circuit the average forecasted load increases due to the impact of the forecasted layers in this scenario.

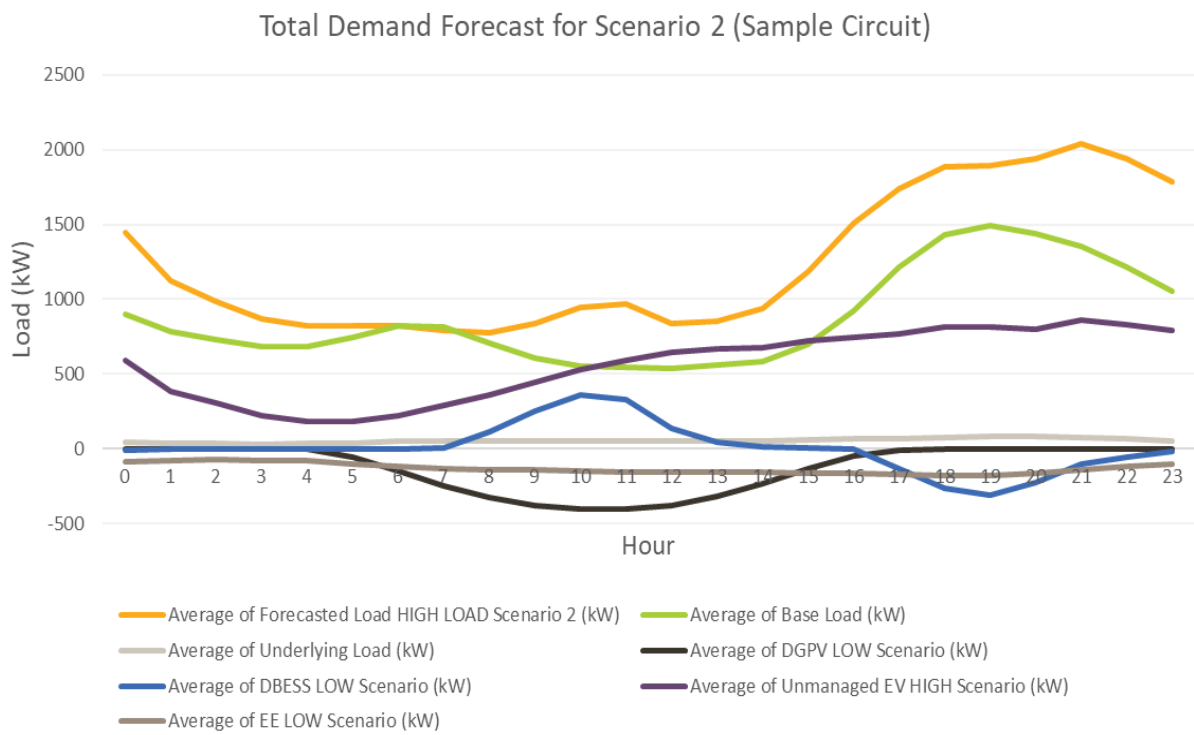


Figure 24: Total Demand Forecast for Scenario 2 (Sample Circuit)

This chart displays the same information as the previous, however it emphasizes the contribution of the forecast layers on the forecasted load shape. For this circuit there is a large contribution due to EV on the average peak forecasted load.

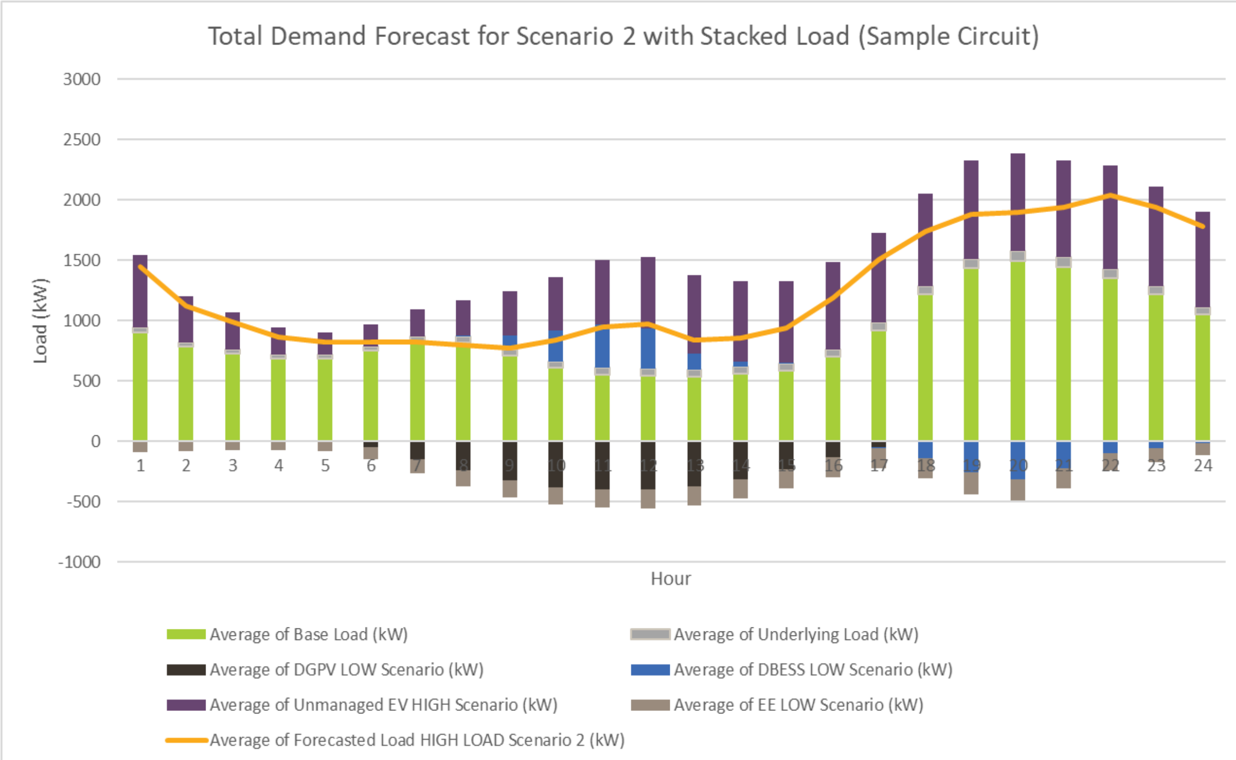


Figure 25: Total Demand Forecast for Scenario 2 with Stacked Load (Sample Circuit)

2.4.1.3 Scenario 3 – Low Load Customer Technology Adoption Bookend

The following average daily hourly load profiles for a sample circuit in Scenario 3, the Low Load Customer Technology Adoption Bookend scenario, are shown in the figure below for comparison:

- Underlying Load
- DGPV and DBESS High Forecast
- Managed EV Low Forecast
- Energy Efficiency High Forecast

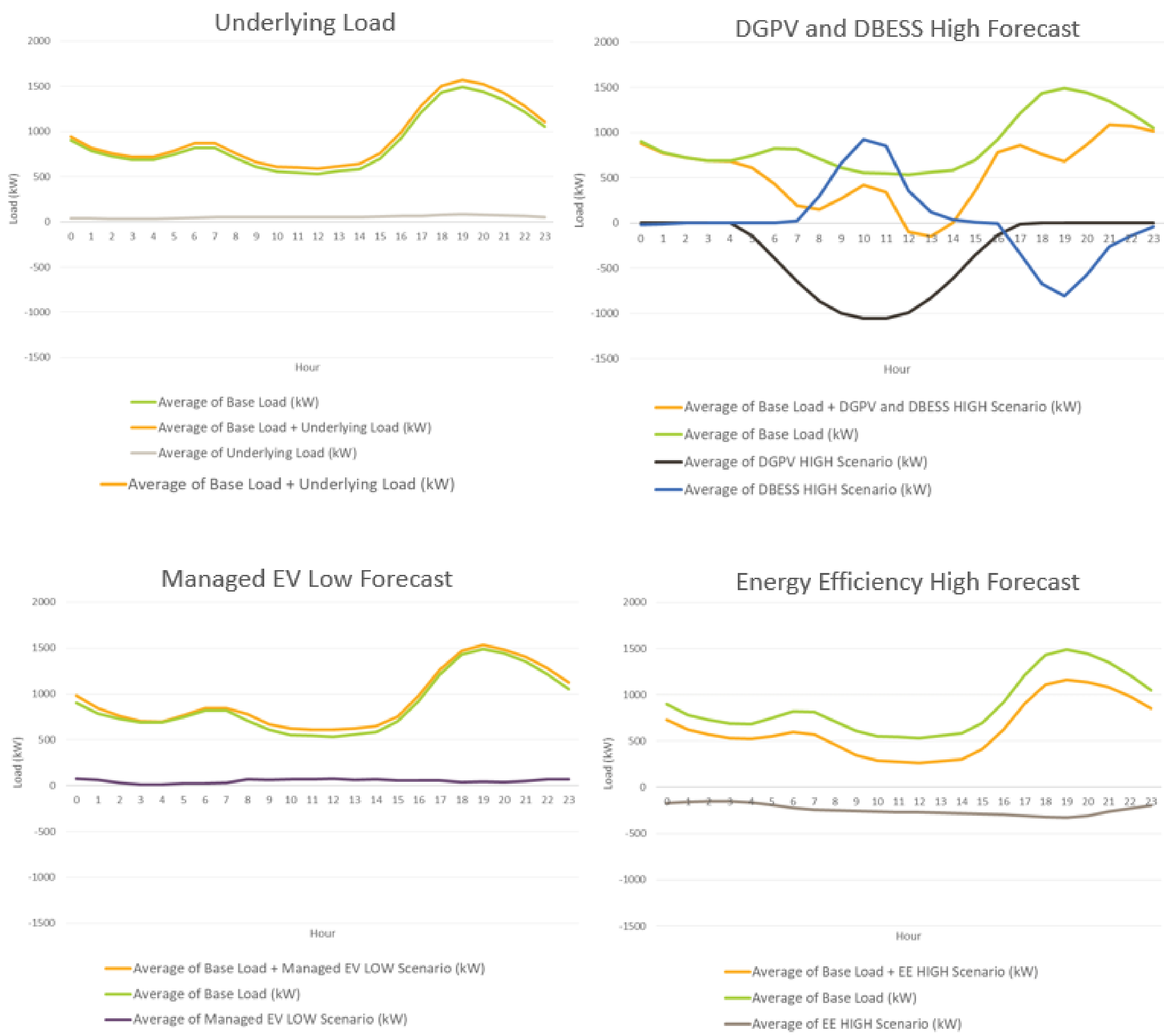


Figure 26: Scenario 3 Average Daily Hourly Load Profiles by Layer (Underlying Load, DGPV and BESS, EV, and EE) for Sample Circuit

As shown for Scenario 1 and 2 in the previous sections, the following figures display the same information as the above figures, but with emphasis on the effect of the aggregated (or stacked) load layers that results in the average shape by layer.

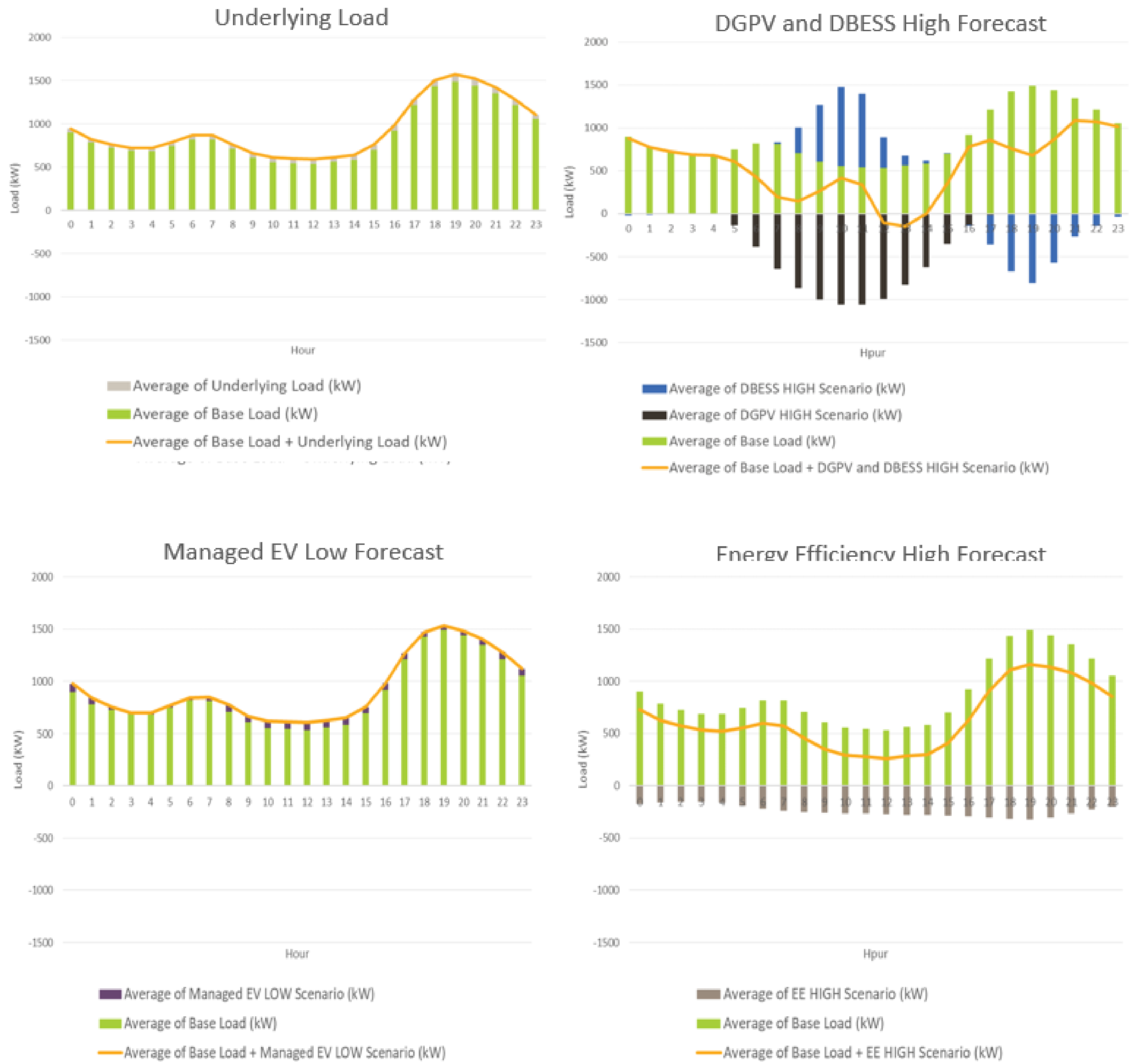


Figure 27: Scenario 3 Average Daily Hourly Load Profiles by Layer (Underlying Load, DGPV and BESS, EV, and EE) with Stacked Load for Sample Circuit

Scenario 3 – Total Forecast

This chart shows the average base load and average forecasted load for the Low Load Technology Adoption Bookend Scenario. For this circuit the average forecasted load decreases due to the impact of the forecasted layers in this scenario.

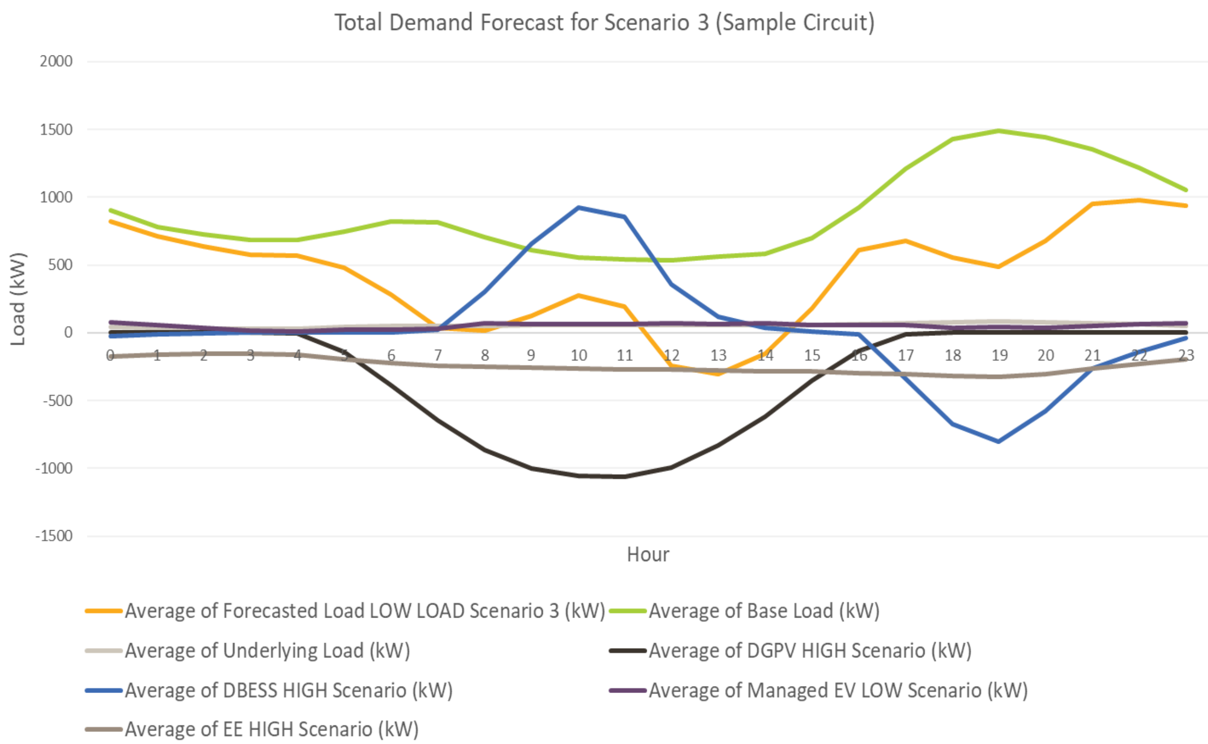


Figure 28: Total Demand Forecast for Scenario 3 (Sample Circuit)

This chart displays the same information as the previous, however it emphasizes the contribution of the forecast layers on the forecasted load shape. For this circuit there is a large contribution due to DGPV and DBESS on the average forecasted load.

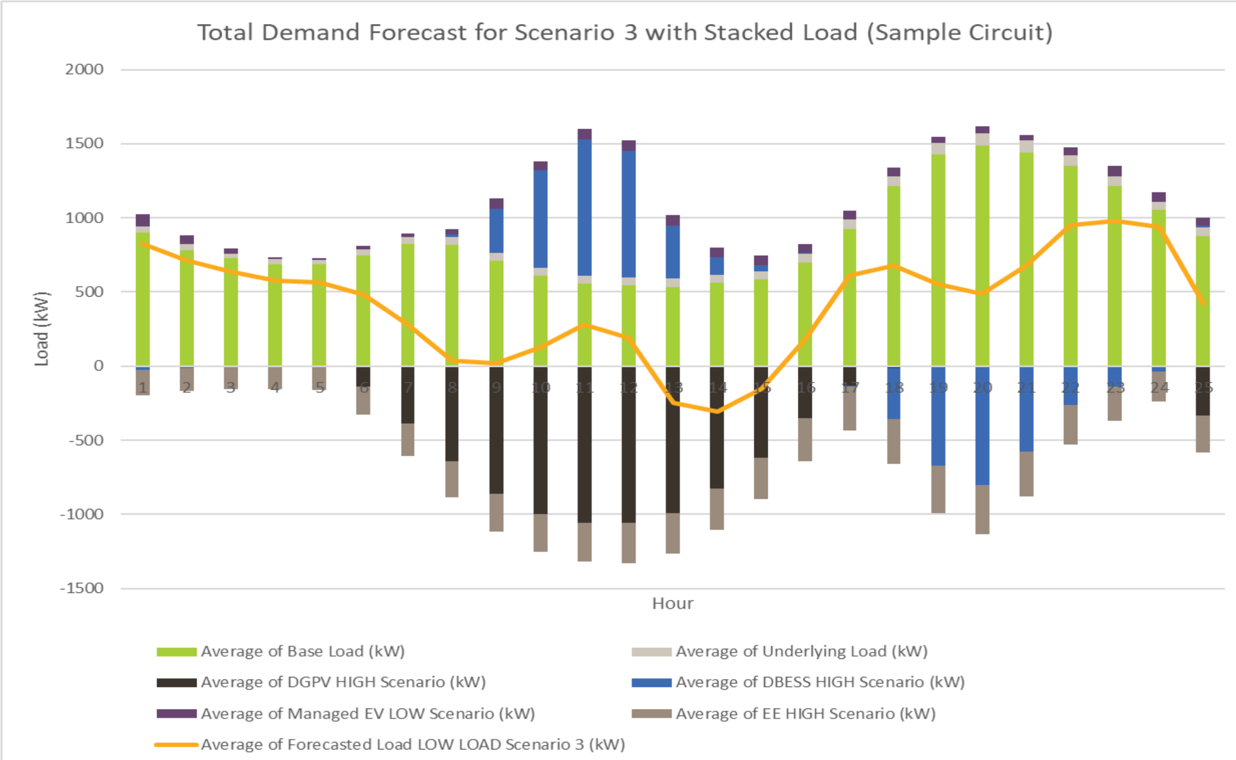


Figure 29: Total Demand Forecast for Scenario 3 with Stacked Load (Sample Circuit)

The process for extracting 8760 hourly data for the circuits and transformers from LoadSEER can be performed individually by scenario, layer selection, circuit (or transformer), and year. For each combination, a single file is required to be created and downloaded, which makes the process of extracting the 8760 hourly data for all scenarios, layers, circuits, transformer, and years time consuming and labor intensive. Therefore, the above sample circuit was selected to illustrate the effect of each layer under the different scenarios. The total demand forecast is described further in Section 3.1.

2.4.2 Forecast Allocation Based on Base Load and DGPV

The forecast allocation for Hawai'i Island and Maui County is based on existing load and DGPV as LoadSEER models are not yet available for these islands. This procedure mimics the allocation steps done in LoadSEER, but through a manual process. Therefore, the resulting location-based demand forecasts are not provided in a form as granular as the forecasts developed using LoadSEER. Through this manual process, peak load values are determined for each layer rather than the hourly demand profiles that LoadSEER can create. In general, the annual corporate forecast layers described in Section 2.3 are allocated amongst circuits using an allocation percentage for each circuit based on the base load or DGPV.

2.4.2.1 Forecasted Load Growth

As described in Section 2.3.1., the total annual underlying load to be allocated is first reduced by the total amount (MW) of service requests anticipated in the respective year to avoid double counting future loads. Next, the remaining underlying load is distributed amongst the circuits.

The amount allocated to each circuit is calculated based on the percentage of a circuit's base load relative to the sum of the base load for all circuits. This allocation process is repeated for each year (2021 through 2030) using the same percentage.

Finally, the underlying load allocated to each circuit is summed with the load growth adjustments (service requests) described in Section 2.2. to create the total forecasted load growth by circuit by year.

In summary, the steps to allocate the forecasted load growth by year is:

1. Determine the base load as a percentage of the sum of all circuit base loads.

$$\%\ Circuit\ Allocation_{Base\ Load} = \frac{Circuit\ Base\ Load}{\sum Circuit\ A\ Base\ Load + Circuit\ B\ Base\ Load + \cdots + Circuit\ n\ Base\ Load}$$

2. Determine the total underlying load to be allocated after accounting for service requests.

$$Total\ Underlying\ Load = Underlying\ Load\ Forecast - Service\ Requests$$

3. Allocate the underlying load from Step 2 using the percent allocation from Step 1.

$$\text{Underlying Load Allocation} = (\%\ Circuit\ Allocation_{Base\ Load}) \times (Total\ Underlying\ Load)$$

4. Sum the underlying load allocation from step 3 to the load growth adjustments described in Section 2.2.for the respective year.

$$Forecasted\ Load\ Growth = Service\ Requests + Underlying\ Load\ Allocation$$

5. Repeat steps 2 through 4 for each year in the study period.

While these steps are followed for Hawai'i Island and Lana'i, total amount of load anticipated due to service requests is greater than the underlying load forecast. Thus, only the service requests are allocated to the specific circuits where the new load growth is anticipated.

2.4.2.2 DER (DGPV and BESS)

The allocation of the DGPV and DBESS layers follow a similar procedure as the underlying load allocation in the previous section. However, rather than allocating the DER based on a circuit peak percentage, the allocation percentage is based on the historical residential DGPV allocation. This is consistent with the methodology used to determine the DER forecast allocation based on existing DER described in the *Distribution DER Hosting Capacity Grid Needs* document provided in the August Update.[21,22]

In summary, the steps to allocate the DER layers by year are:

1. Calculate the executed DGPV in the selected programs[23] on each circuit as a percentage of total executed DGPV in those selected programs on that island.

$$\%\ Circuit\ Allocation_{DGPV} = \frac{Executed\ DGPV\ in\ selected\ programs\ on\ Circuit}{Total\ Executed\ DGPV\ in\ selected\ programs}$$

2. Allocate the DGPV layer (e.g., DBESS or DGPV) from Section 2.3.2 using the percent allocation from Step 1.

$$\text{DGPV Allocation} = (\%\ Circuit\ Allocation_{DGPV}) \times (Total\ DGPV\ Load)$$

3. Repeat step 2 for each year in the study period.

The above steps are used for both the DBESS and DGPV layers.

2.4.2.3 Electric Vehicle

The electric vehicle load layer allocation follows a similar process as the DER allocation described in Section 2.4.2.2. The EV load layer described in Section 2.3.3. is distributed

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[21] *See* https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/20210803_heco_submittal_of_igp_inputs_and_assum_and_der_hosting_capacity.pdf

[22] This is also consistent with the methodology described in the *Distribution DER Hosting Capacity Grid Needs November 2021 Update* filed concurrently with this report (Nov. 2021, Dkt. No. 2018-0165).

[23] Selected programs include: Net Energy Metering ("NEM"), Feed-In Tariff ("FIT"), Customer Grid Supply ("CGS"), Customer Self-Supply ("CSS"), Customer Grid Supply Plus ("GSP"), Smart Export ("ISE"), Net Energy Metering Plus ("NEM Plus" or "NMP"), Standard Interconnection Agreement ("SIA"), Community-Based Renewable Energy ("CBRE") Phase 1, Power Purchase Agreement ("PPA").

amongst the circuits using the % Circuit Allocation based on residential DGPV calculated in step 1 of Section 2.4.2.2.

In summary, the steps to allocate the electric vehicle load by year are:

1. Allocate the electric vehicle load from Section 2.3.3 using the percent circuit allocation based on residential DGPV.

$$\text{EV Load Allocation} = (\%\ Circuit\ Allocation_{DGPV}) \times (Total\ EV\ Load)$$

2. Repeat step 1 for each year in the study period.

2.4.2.4 Energy Efficiency

The energy efficiency load layer allocation follows a similar process as the underlying load allocation described in Section 2.4.2.1. The energy efficiency load layer described in Section 2.3.4. is distributed amongst the circuits using the % Circuit Allocation calculated in step 1 of Section 2.4.2.1.

In summary, the steps to allocate the energy efficiency load by year are:

1. Allocate the energy efficiency load from Section 2.3.4 using the percent circuit allocation.

$$\text{EE Load Allocation} = (\%\ Circuit\ Allocation_{Base\ Load}) \times (Total\ EE\ Load)$$

2. Repeat step 1 for each year in the study period.

2.4.2.5 Total Demand Forecast

To create the location-based forecast, the annual values for each layer on each circuit are aggregated by year for years 2021 through 2030. The forecast layers for the forecasted load growth, DER (DGPV and DBESS), EV, and EE are added to the base load (See Section 2.1) to create the total demand forecast.

In summary, the total demand forecast for each year is:

$$Total\ Demand\ Forecast = \sum Base\ Load + Forecast\ Layers\ (Forecasted\ Load\ Growth, DER, EV, EE)$$

The total demand forecast is described further in Section 3.

3 Location-Based Forecasts

The location-based forecasts derived using the process described in Section 2 are provided by circuit and by transformer consistent with grid needs documentation described in the *Distribution Planning Methodology.*[24]

3.1 DEMAND FORECAST

The demand forecast lists the grid assets and shows the net peak forecast for these assets for years 2021 through 2030 and include:

- **Facility Type**: Substation transformer and/or circuit
- **Facility Name**: Substation transformer and circuit names
- **Equipment Rating (MVA)**: Transformer rating[25]
- **Peak Load (MW)**: Peak circuit load forecast for corresponding year

Demand forecasts by Circuit and Demand Forecasts by Transformer available on the Company website (see Appendix A: for a description of the files provided).

The following chart is a visual representation of the data that is provided in the demand forecast. The chart shows the peak day for 2030, extracted from the same residential circuit 8760 hourly Base scenario forecast shown in the previous section. The green plot is the Peak Day Base Load (historical load) and the orange plot is the total forecasted load (shown as Peak Day Forecasted Load BASE Scenario 1). The peak load value of the total forecasted load (orange) corresponds to the 2030 peak load value provided in the demand forecasts for circuits and transformers.

[24] DP methodology at 19.

[25] Transformer rating provided is the larger rating with fans operating ("FA") if applicable; otherwise, the rating with fans off ("OA") is provided.

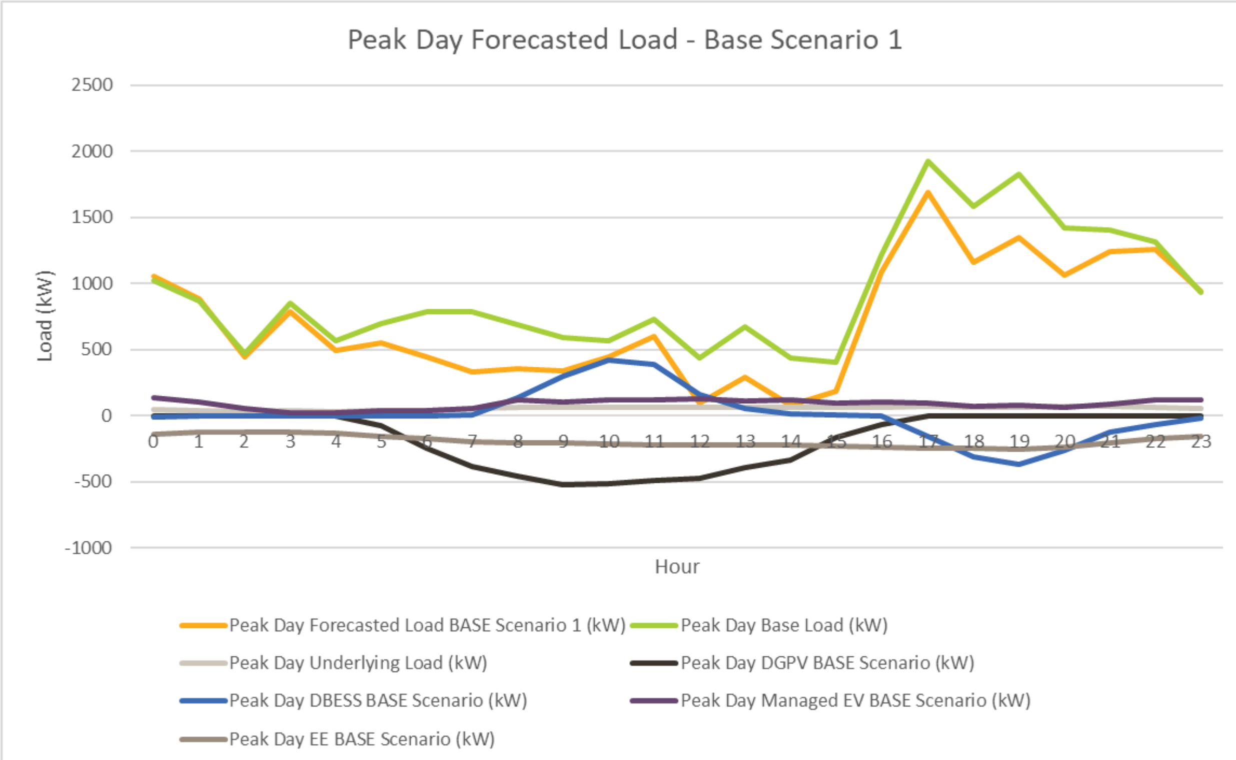

Figure 30: Peak Day Forecasted Load – Base Scenario 1

Note the sum of the circuit forecasts do not add up to the total transformer forecast. This occurs because the peaks of those circuits are not coincident and occur at different times throughout the year, whereas the transformer peak is determined as the peak of the combined hourly circuit profiles.

3.2 DEMAND FORECAST BY LOAD TYPE

A demand forecast by load type is provided for years 2021 through 2030. For each circuit, the corresponding transformer along with the following load type allocation is provided for each corresponding year on the Company website (see Appendix A: for a description of the files provided):

- **Forecasted Load Growth**: Underlying load allocation and new service requests
- **Base Load:** Historical peak demand[26]
- **DGPV**: Distributed generation photovoltaic systems load allocation
- **DBESS**: Distributed battery energy storage systems load allocation

[26] Provided for Hawai'i Island and Maui County (Maui, Lāna'i, and Moloka'i) only. See Section 2.1.

- **Electric Vehicle Charging**: Managed or Unmanaged EV Charging load allocation
- **Energy Efficiency**: Energy efficiency load allocation

Similar to the non-coincidence of the circuit peaks to transformer peak, the demand forecast peak value for each year is determined by the summation of all the hourly forecast layers and underlying load. The values listed in the appendices show the maximum values of each layer for each year, which likely occur at different times throughout the year. Because of the noncoincidence of the values listed in the tables, the sum of those forecast values listed will not equal the net forecast value as illustrated in Figure 30 above.

To compare the impact of the different scenarios and layers, in addition to the residential circuit shown in the previous sections, the 8760 hourly data for a primarily commercial circuit was also compiled from LoadSEER. Both circuits have a relatively large amount of DGPV allocated in the circuit level forecast. A comparison of the circuits and the impact of the scenarios and different layers is discussed in the following sections.

3.2.1 Residential Circuit Example Using LoadSEER

The following chart is a comparison of the average hourly demand forecast (shown as Forecasted Load) for the final forecast year (2030) for the three scenarios for a circuit with primarily residential customers. Each line represents the average forecasted load for 2030 for a different scenario. The primarily residential circuit shows a noticeable difference between the three scenarios. The magnitude of the allocation is large in comparison to the existing load on the circuits, so their impact is more visible than on the primarily commercial transformer example in the following section.

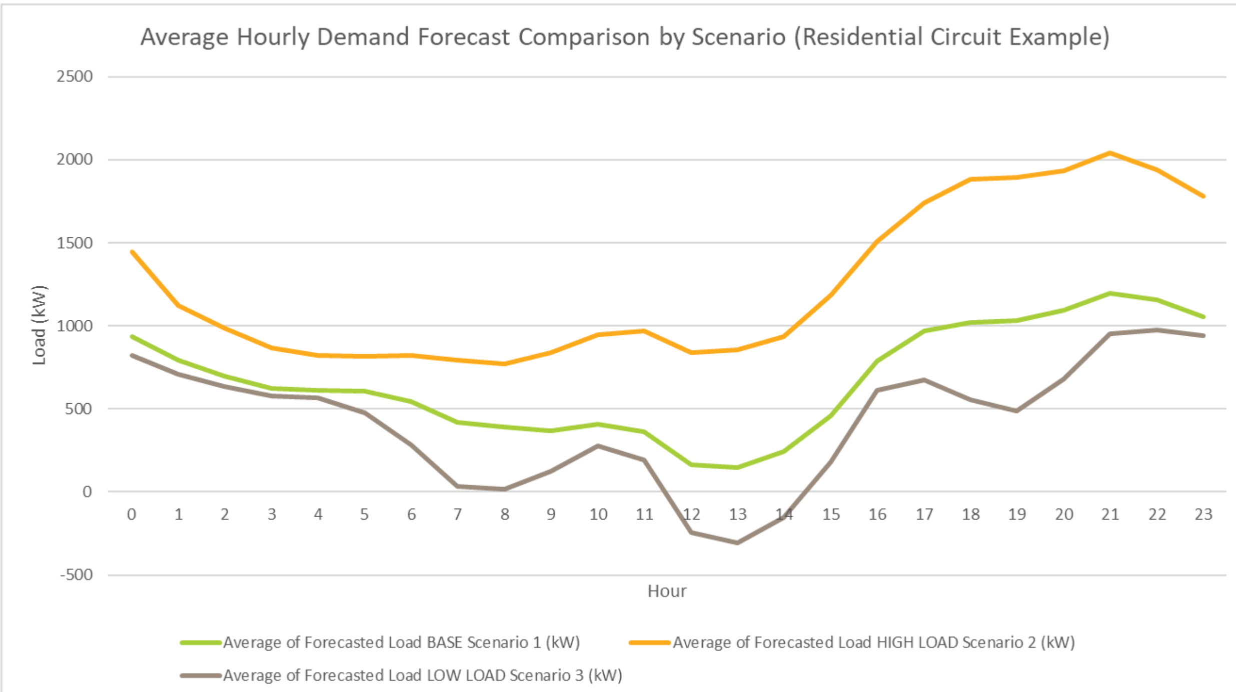

Figure 31: Average Hourly Demand Forecast Comparison by Scenario (Residential Circuit Example)

The following charts are for the Base scenario and shows the average base load, average forecasted load, and the individual forecast layers. This chart shows the forecasted hourly load shape and illustrates the impact the forecast layers have on the base load.

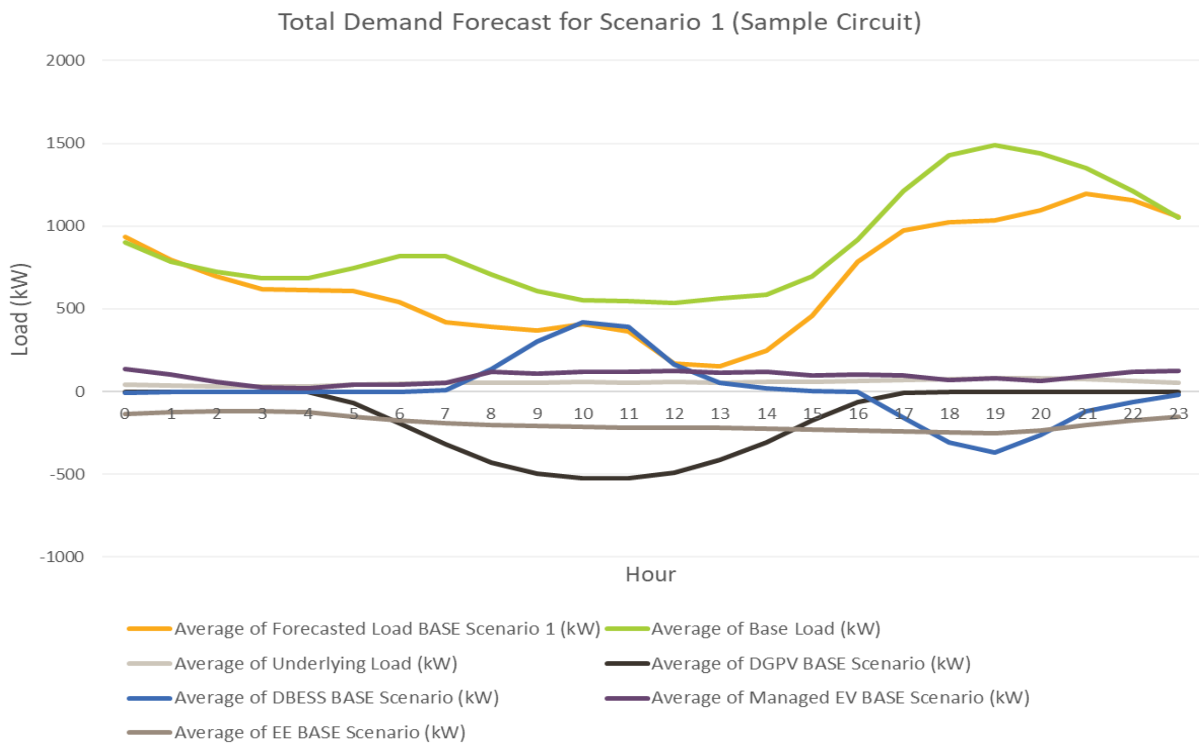

Figure 32: Hourly Demand Forecast (Residential Circuit Example)

The following chart is for the Base scenario and shows the average load profiles for the underlying load, DGPV, DBESS, EV, EE, and the cumulative impact of all the layers. The peak values provided in the demand forecast by load type are non-coincident, which can be visualized with this chart; the peak value for each layer occurs at different times.

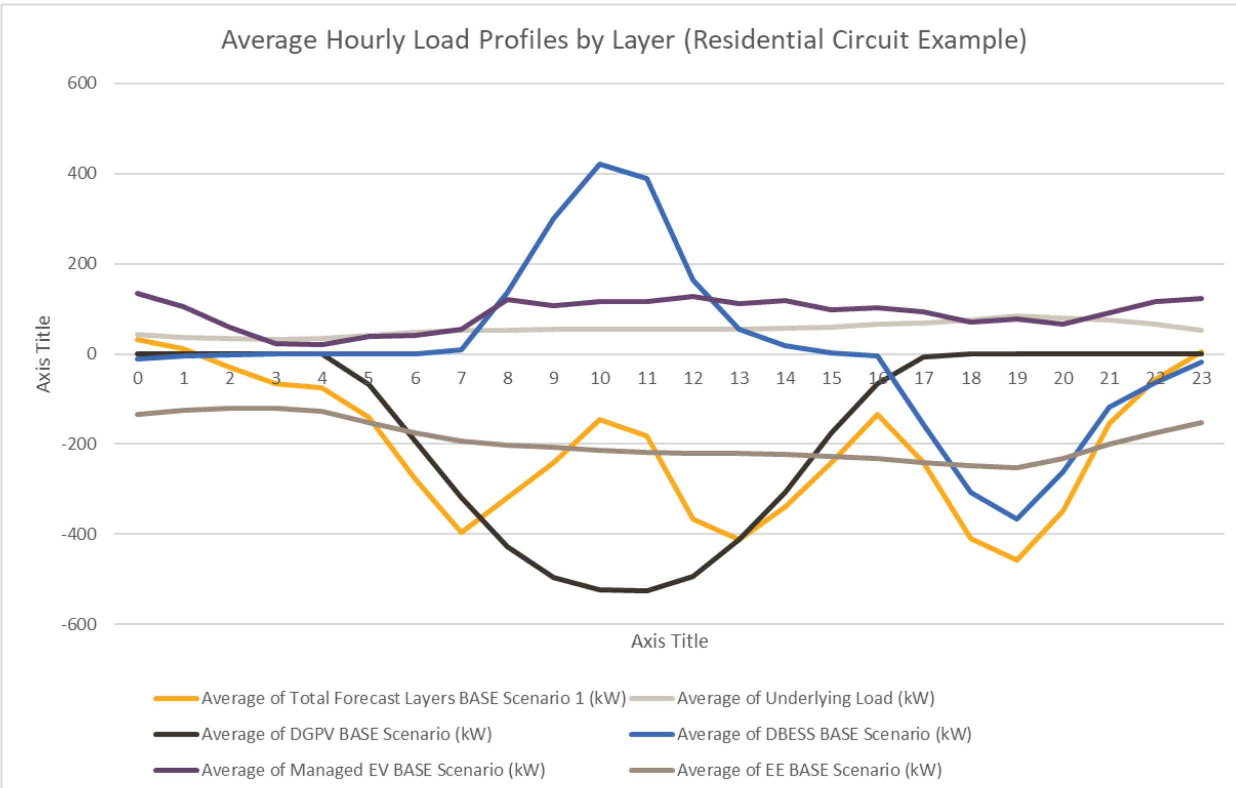

Figure 33: Average Hourly Load Profiles by Layer (Residential Circuit Example)

The following charts are for the Base scenario and show the forecasted peak day for 2030. This chart shows the forecasted hourly load shape and illustrates the impact the forecast layers have on the base load.

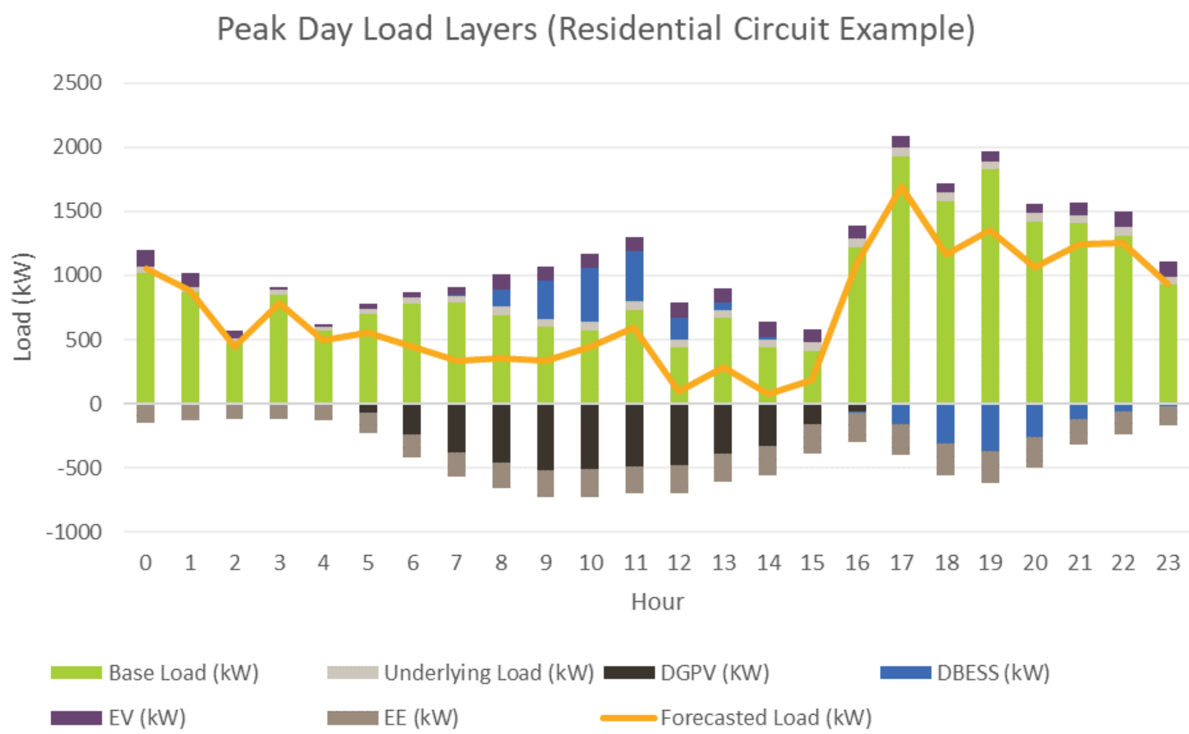

Figure 34: Peak Day Load Layers (Residential Circuit Example)

This chart includes the same layer data as the previous without the base load or forecasted load to focus on the individual layer contributions.

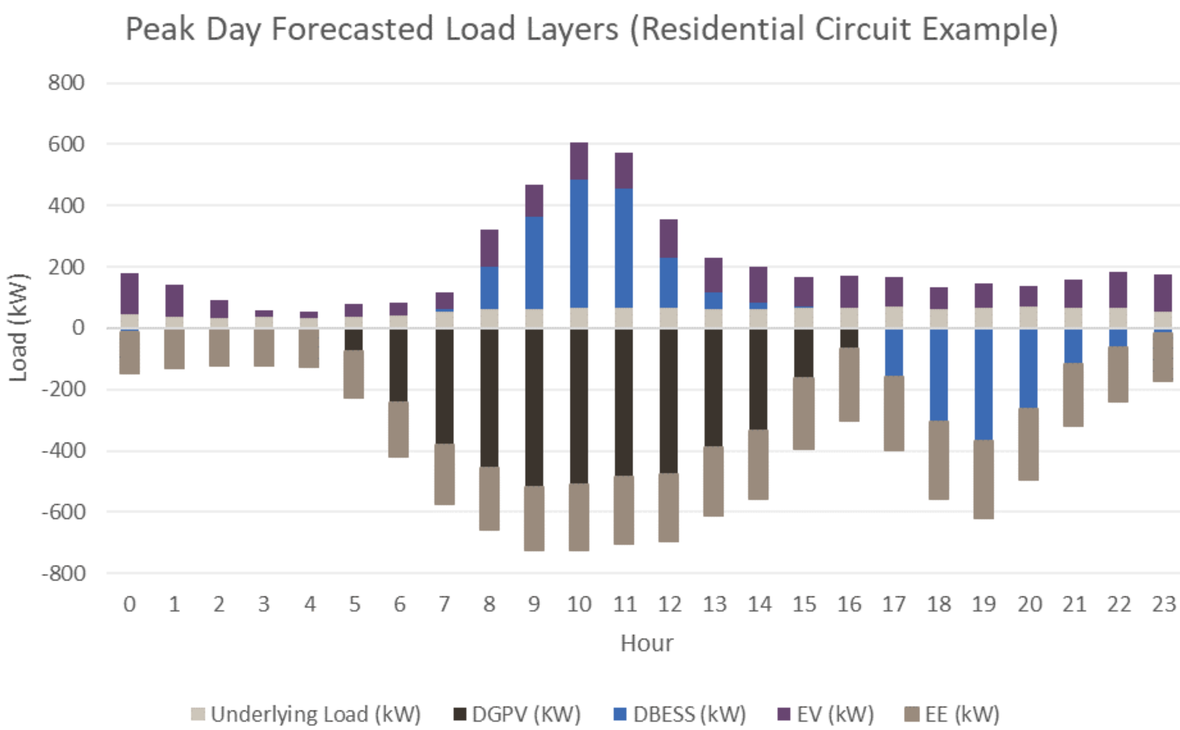

Figure 35: Peak Day Forecasted Load Layers (Residential Circuit Example)

3.2.2 Commercial Transformer Example Using LoadSEER

The following chart is a comparison of the average hourly demand forecast (shown as Forecasted Load) for the final forecast year (2030) for the three scenarios for a transformer with primarily commercial customers. Each line represents the average forecasted load for 2030 for a different scenario. The magnitude of the forecast layers is smaller in comparison to the existing load and service requests, so the cumulative impact of the different scenarios for this mainly commercial transformer is more subtle in comparison to the primarily residential circuit example in the previous section.

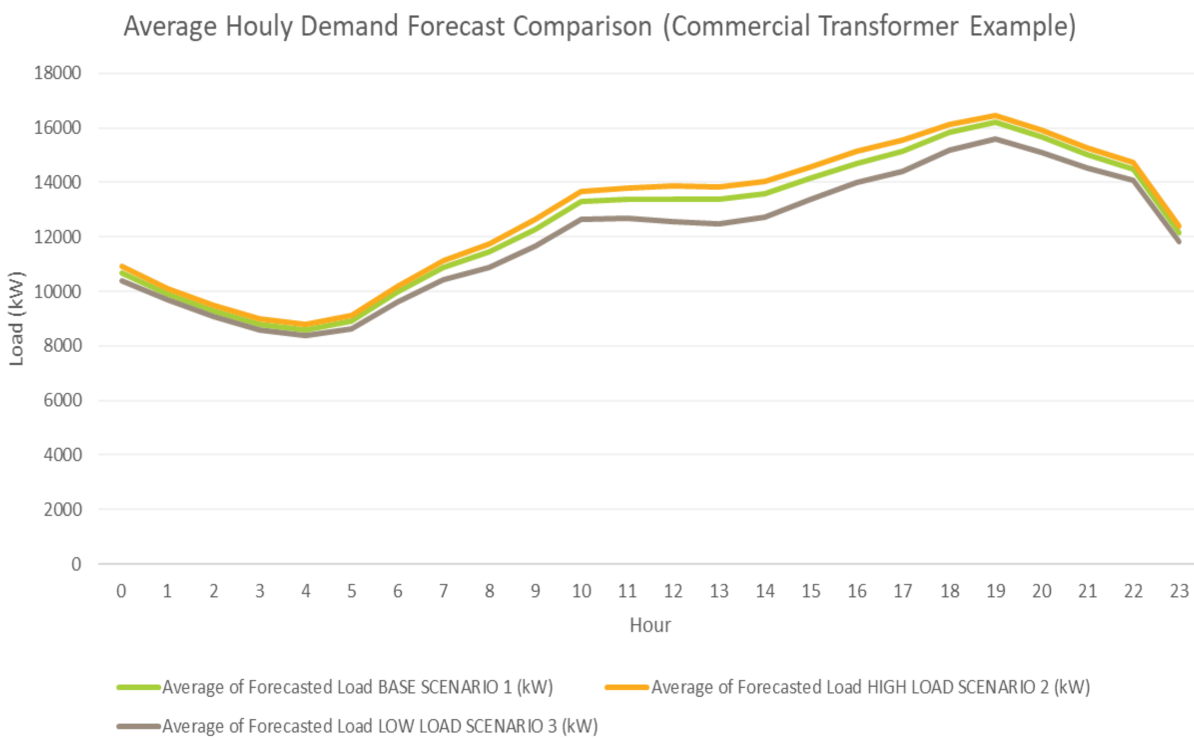

Figure 36: Average Hourly Demand Forecast Comparison by Scenario (Commercial Transformer Example)

The following charts are for the Base scenario and shows the average base load, average forecasted load, and the individual forecast layers. This chart shows the forecasted hourly load shape and illustrates the impact the forecast layers have on the base load.

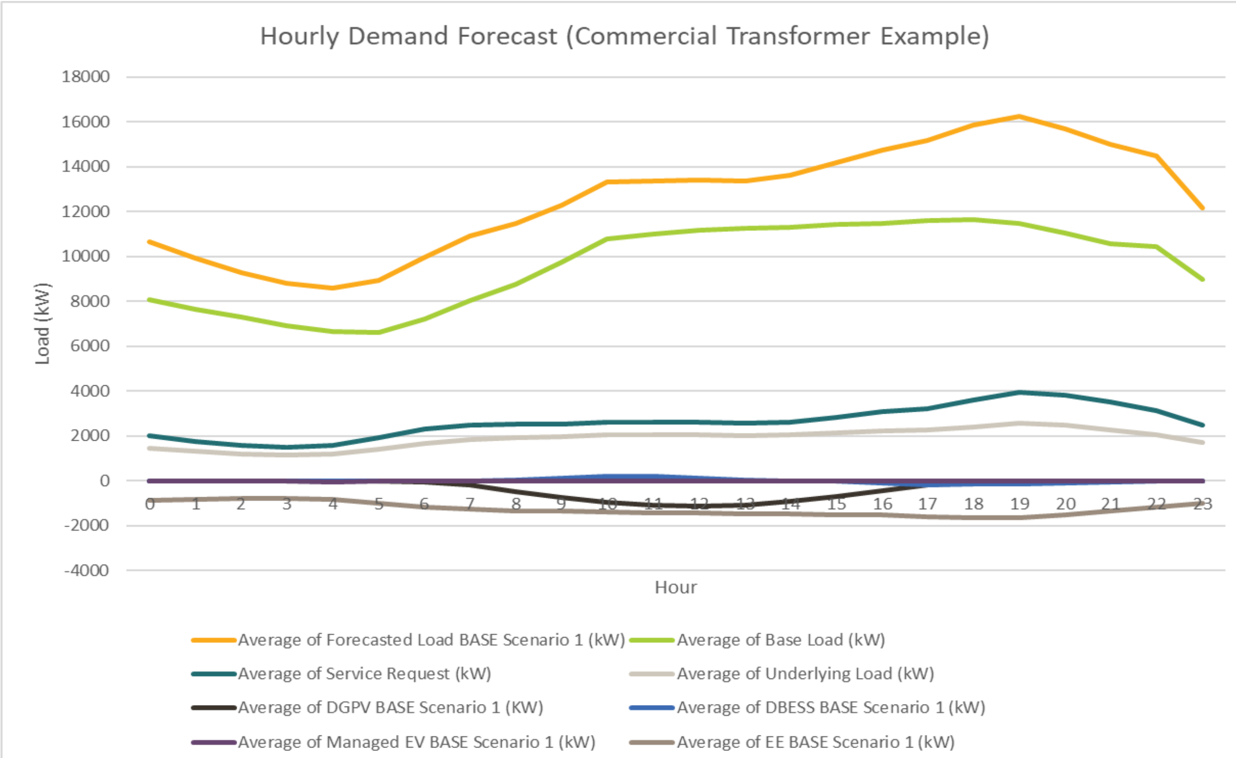

Figure 37: Hourly Demand Forecast (Commercial Transformer Example)

The following chart is for the Base scenario and shows the average load profiles for the service requests, underlying load, DGPV, DBESS, EV, EE, and the cumulative impact of all the layers. The peak values provided in the demand forecast by load type are non-coincident, which can be visualized with this chart; the peak value for each layer occurs at different times.

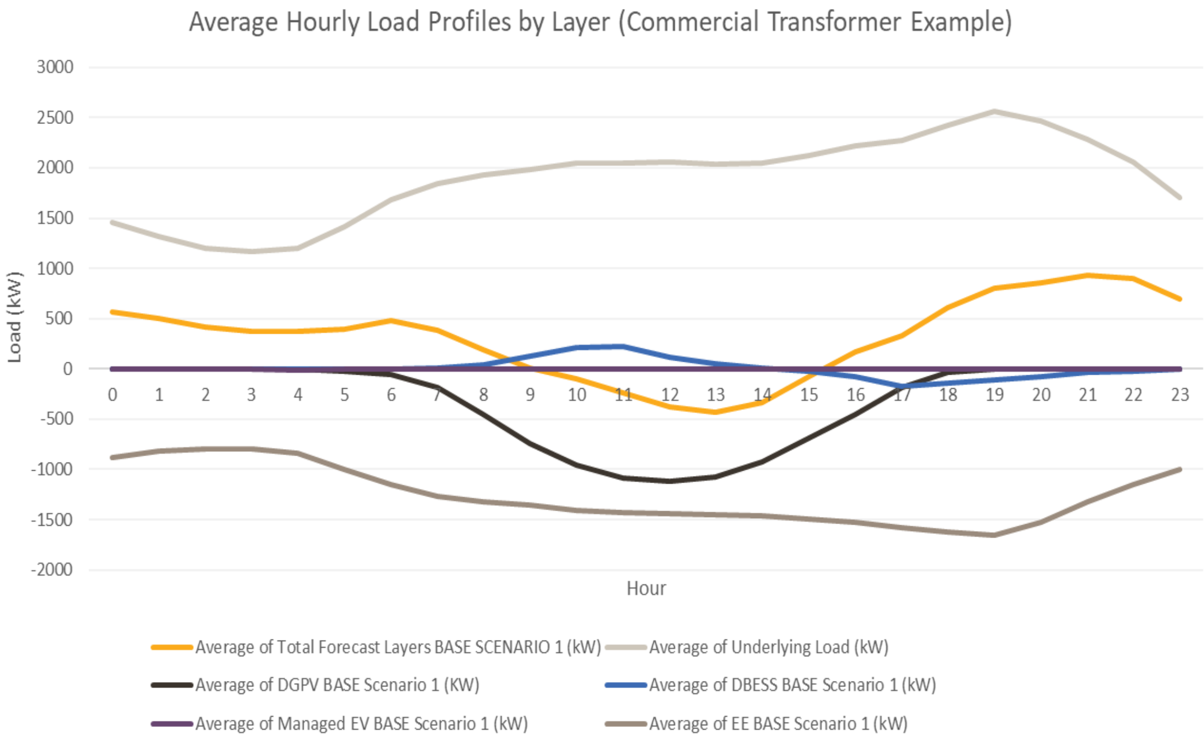

Figure 38: Average Hourly Load Profiles by Layer (Commercial Transformer Example)

The cumulative impact of all layers for each hour is shown below as the Forecasted Load in the following figure and compared against the individual load layers. The following charts are for the Base scenario and show the forecasted peak day for 2030. This chart shows the forecasted hourly load shape and illustrates the impact the forecast layers have on the base load.

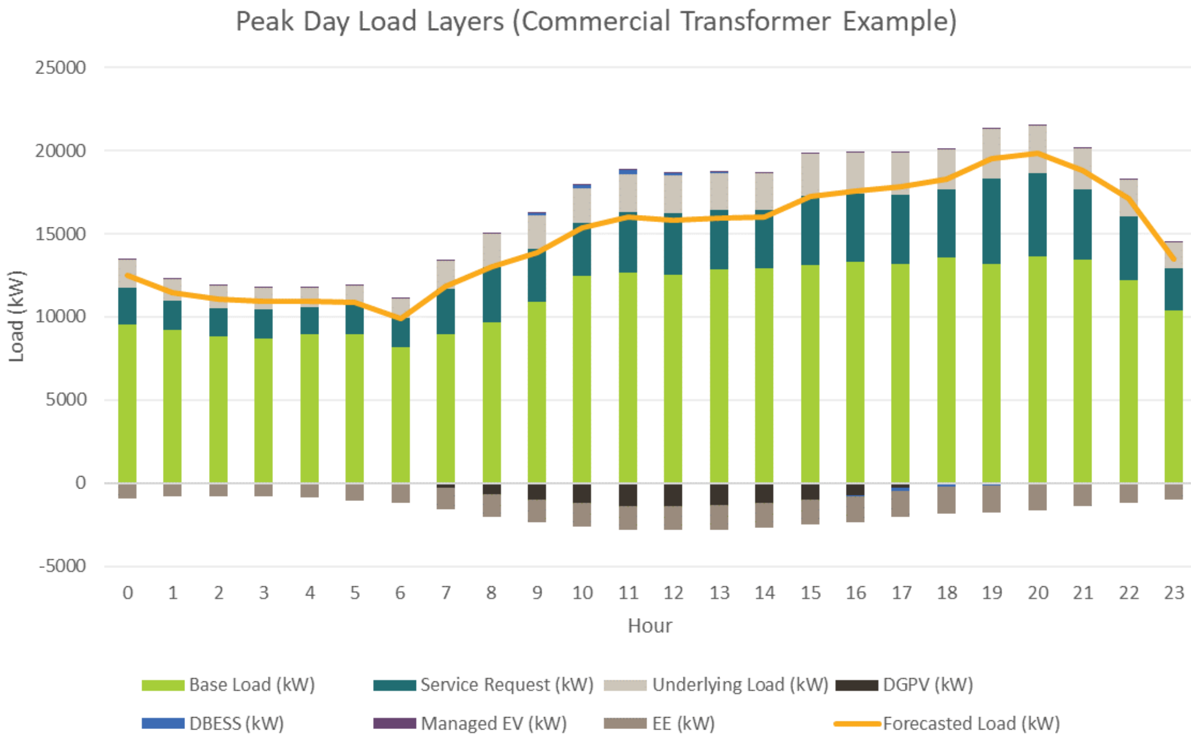

Figure 39: Peak Day Load Layers (Commercial Transformer Example)

This chart includes the same layer data as the previous without the base load or forecasted load to focus on the individual layer contributions.

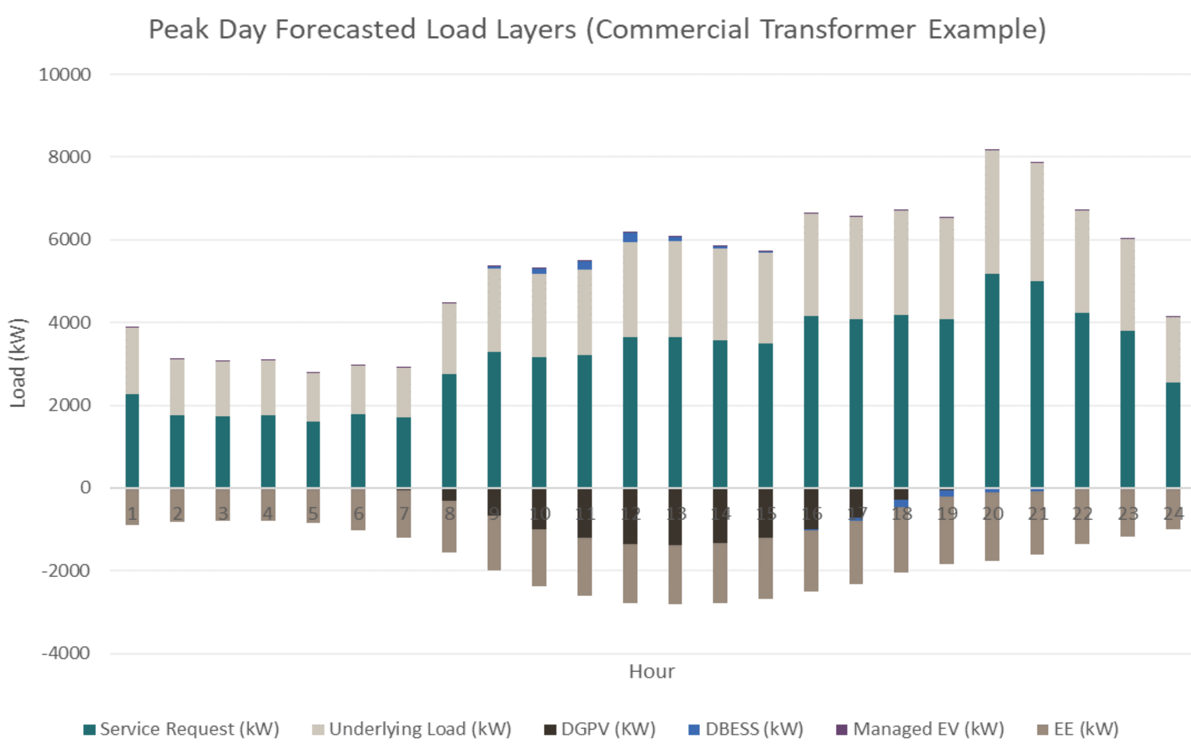

Figure 40: Peak Day Forecasted Load Layers (Commercial Transformer Example)

3.2.3 Circuit Example Based on Existing Load and DGPV

The charts in this section depict the total demand forecasts for a circuit on Hawai'i Island or Maui County that was developed with the different layers allocated based on the existing load and DGPV rather than through LoadSEER.

The following chart shows the total demand forecast under the three modeling scenarios for this example circuit.

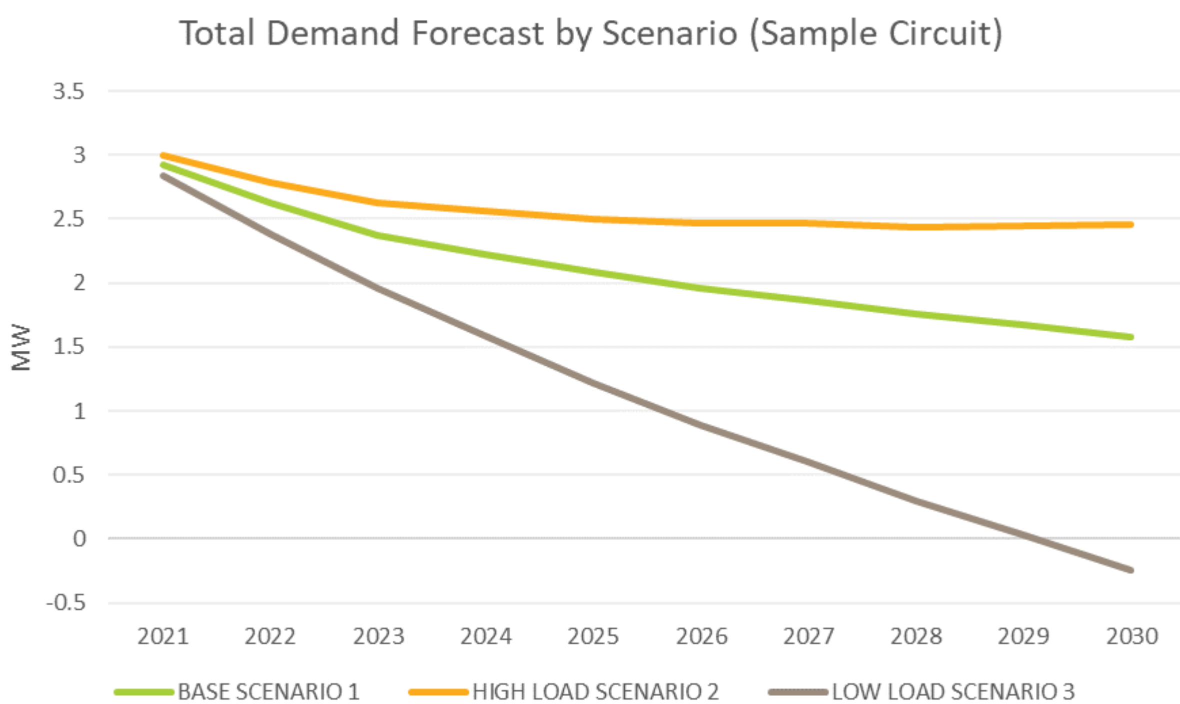

Figure 41: Total Demand Forecast Comparison by Scenario

The following charts show the total demand forecast by modeling scenario for the same example circuit broken down into the forecast layers. Since the forecast layers are small in comparison to the base load and total demand forecast, charts are also included with the total demand forecast and the base load layer removed to give a better picture of the breakdown of the Forecasted Load Growth, DER, EE, EV layers.

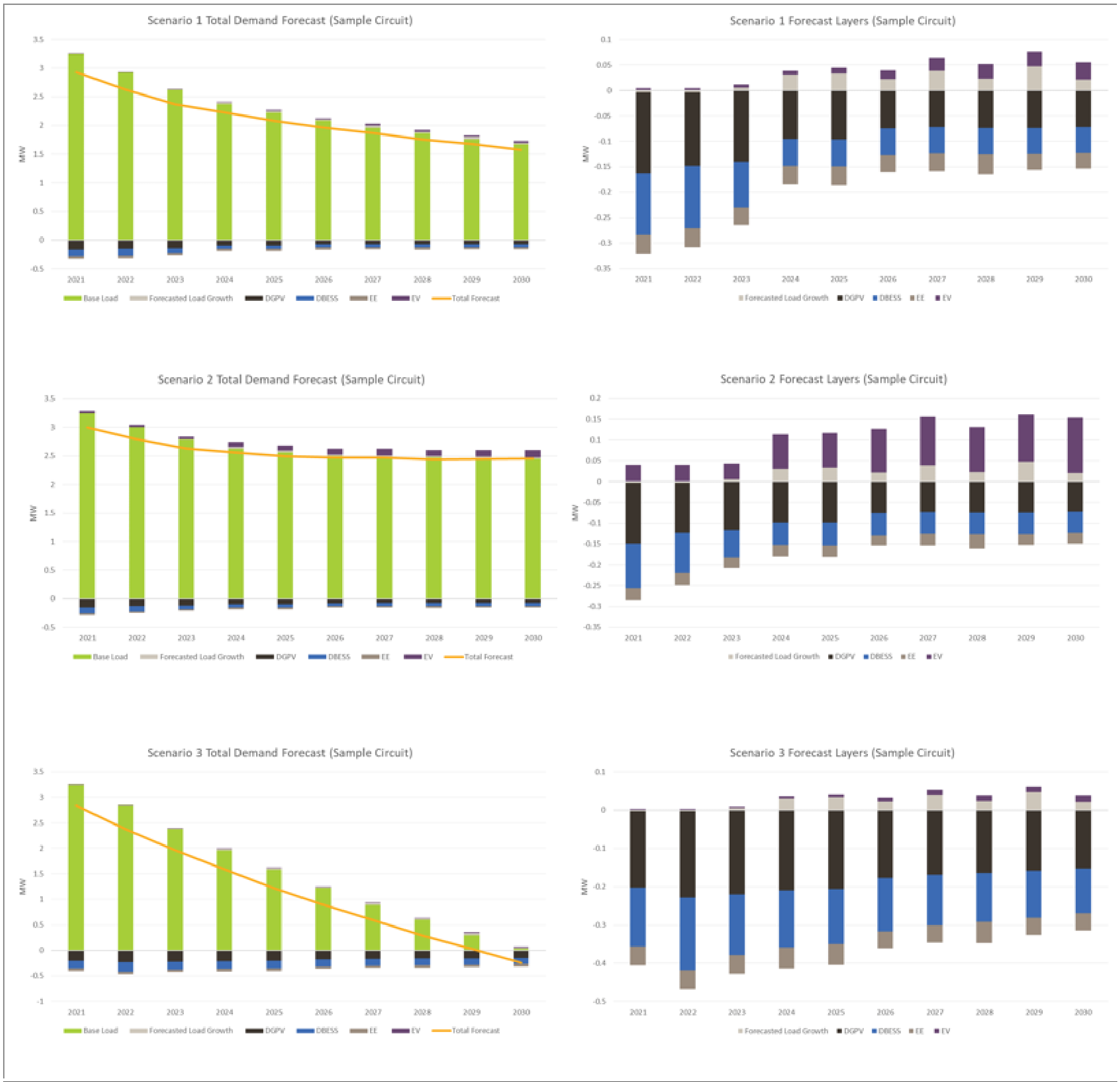

Figure 42: Total Demand Forecast and Forecast Layers by Scenario

4 Next Steps

As mentioned earlier, this document describes the first step of the Distribution Planning Process, the Forecast Stage.

A preliminary version of this report[27] and sample forecasts were provided to the Stakeholder Technical Working Group ("STWG") for review and to receive feedback. The process to derive the forecasts was discussed with the Stakeholder Technical Working Group ("STWG") on October 6, 2021. Shortly thereafter on October 8, 2021, the location-based forecasts for each island and each scenario were provided on the Company website as well for review.[28] A summary of the feedback received from the STWG is discussed in Appendix B: and will be considered for incorporation into the GNA Review Point.

After review, no revisions to the forecasts provided on October 8 were necessary at this time. A summary of the forecasts available on the Company website is outlined in Appendix A:.

In the next stage of the planning process, the analysis stage, the location-based forecasts will be used to assess the adequacy of the electric distribution system by comparing the forecasts against the distribution planning criteria. Through this next step, grid needs required to serve load growth and accommodate higher levels of DER will be identified.

[27] *See* https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/20211008_location_based_distribution_forecasts_draft.pdf

[28] *See* https://www.hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning/stakeholder-engagement/key-stakeholder-documents

Appendix A: Workbook Index

The location-based forecasts for each scenario by island are available on the Company's website in Excel workbooks as the tables are too voluminous to provide in table format herein.[29]

A summary of the workbooks is provided below.

Table A-1: Location-Based Distribution Forecasts Workbook Index

Island	Scenario	Modeling Case	Workbook[30]
O'ahu	1	Base	Oahu Location-Based Forecasts Scenario 1 (EXCEL)
	2	High Load Customer Technology Adoption Bookend	Oahu Location-Based Forecasts Scenario 2 (EXCEL)
	3	Low Load Customer Technology Adoption Bookend	Oahu Location-Based Forecasts Scenario 3 (EXCEL)
Hawai'i Island	1	Base	Hawaii Location-Based Forecasts Scenario 1 (EXCEL)
	2	High Load Customer Technology Adoption Bookend	Hawaii Location-Based Forecasts Scenario 2 (EXCEL)
	3	Low Load Customer Technology Adoption Bookend	Hawaii Location-Based Forecasts Scenario 3 (EXCEL)
Maui Island	1	Base	Maui Location-Based Forecasts Scenario 1 (EXCEL)

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

[30] File name as it appears on the Company website.

Island	Scenario	Modeling Case	Workbook[30]
	2	High Load Customer Technology Adoption Bookend	Maui Location-Based Forecasts Scenario 2 (EXCEL)
	3	Low Load Customer Technology Adoption Bookend	Maui Location-Based Forecasts Scenario 3 (EXCEL)
Lanaʻi	1	Base	Lanai Location-Based Forecasts Scenario 1 (EXCEL)
	2	High Load Customer Technology Adoption Bookend	Lanai Location-Based Forecasts Scenario 2 (EXCEL)
	3	Low Load Customer Technology Adoption Bookend	Lanai Location-Based Forecasts Scenario 3 (EXCEL)
Molokaʻi	1	Base	Molokai Location-Based Forecasts Scenario 1 (EXCEL)
	2	High Load Customer Technology Adoption Bookend	Molokai Location-Based Forecasts Scenario 2 (EXCEL)
	3	Low Load Customer Technology Adoption Bookend	Molokai Location-Based Forecasts Scenario 3 (EXCEL)

Appendix B: Stakeholder Feedback

The Company recognizes stakeholder engagement as an integral part of the IGP process. In an effort to proactively solicit stakeholder feedback on this report, the Company provided a draft report to stakeholders for review and comment on October 1, 2021. The Company subsequently met with the STWG on October 6, 2021 to address questions and receive feedback from the stakeholders. Meeting minutes capturing feedback from the discussion and presentation materials from the meeting can be found on the IGP website. [31]

Additionally, the Company received feedback from various Organizations which is consolidated anonymously below. Feedback from stakeholders in this section are shown in bold, and the Company's response to the questions or feedback are shown in italics.

1. **At 39, if the service requests are greater than the underlying load forecast in certain circuits, would this indicate a forecasting error?**

   The corporate underlying load forecast is allocated to the circuit level using spatial forecasting capabilities to aid in the identification of granular pockets of area load growth. The forecasts have inherent uncertainties. In comparison, service requests are actual customer requests for specific new loads which are typically based on detailed watts per unit or watts per square foot estimates.

2. **Are the location-based distribution forecasts calibrated to the overall load forecast (i.e. if all location-based forecasts were summed up, would they equal the overall system load forecast?)**

   The location-based distribution forecasts are related to the overall load forecast by the incremental system load growth that is used as an input file to LoadSEER. Forecasted layers are grown on the distribution circuits until the aggregate amount reaches the respective corporate limit specified by the input files. The aggregated amount will roughly

[31] *See* https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/stakeholder_technical/20211006_stwg_meeting_notes.pdf

equal the incremental value of the corporate forecast. However, because LoadSEER is meant to be used at the distribution level, it is normally not recommended to aggregate forecasts above the substation level and they will not sum to the overall system load forecast.

EXHIBIT 4

Distribution DER Hosting Capacity Grid Needs

Hawaiian Electric

Distribution DER Hosting Capacity Grid Needs

November 2021 Update

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1 Introduction

On August 3, 2021, the Companies submitted their updated and revised Integrated Grid Planning ("IGP") Inputs & Assumptions and Distribution DER Hosting Capacity Grid Needs documents under Docket No. 2018-0165.[1] This document is an update to the Distribution DER Hosting Capacity Grid Needs document.

The distributed energy resources ("DER") hosting capacity grid needs identified in the August 3, 2021 filing were driven by the forecasted DER growth on distribution circuits based on the market DER forecast provided in the 2020 Integrated Grid Planning Inputs and Assumptions March 2021 Update.[2] This DER hosting capacity grid needs update is being filed to reflect the updated DER forecast sensitivities provided in the Hawaiian Electric Revision to Updated and Revised Inputs and Assumptions ("August Update") filed on August 19, 2021.[3] The update provides low, base, and high DER forecast sensitivities to identify hosting capacity grid needs for the next five years. These three sensitivities correspond to low, base, and high scenarios to provide a bookend approach around a reference, or base, forecast. Note that the base (or reference) scenario[4] has also been updated since the August 3 filing. A preliminary report using the high DER forecast, the October 2021 Update, [5] was provided to the Stakeholder Technical Working Group ("STWG") for review and to provide feedback. A summary of the feedback is provided in Appendix B:.[6]

The DER hosting capacity grid needs analysis is part of the Distribution Planning Process employed by the Company to plan the future of the distribution system. The Distribution Planning Process as described in the *Distribution Planning Methodology*[7,8] was developed in

[1] *See* Hawaiian Electric Updated and Revised Inputs and Assumptions & Distribution DER Hosting Capacity Grid Needs filed on August 3, 2021 in Docket No. 2018-0165, Instituting a Proceeding to Investigate Integrated Grid Planning.

[2] *See* https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/forecast_assumptions/20210330_wg_fa_deliverable_draft.pdf

[3] *See* Hawaiian Electric Revision to Updated and Revised Inputs and Assumptions filed on August 19, 2021 in Docket No 2018-0165.

[4] The August 3, 2021 filing was based on the market DER forecast provided in the 2020 Integrated Grid Planning Inputs and Assumptions March 2021 Update. Since then, the IGP DER forecasts were updated and filed on August 3, 2021. The low, base, and high scenarios in this analysis utilize the August 3 updates.

[5] *See* https://www.hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning/stakeholder-engagement/key-stakeholder-documents

The analysis presented herein was revised as needed and results may differ from the October 2021 Update provided on October 1, 2021.

[7] *See* https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/distribution_planning/20200602_dpwg_distribution_planning_methodology.pdf

[8] Concurrent to this filing, an update to the Distribution Planning Methodology was filed in the Grid Needs Assessment (Nov. 2021, Dkt. No. 2018-0165). References in this document are made to the document in footnote 8.

collaboration with stakeholder and customer engagement through the Distribution Planning Working Group ("DPWG"). The document was developed to identify the steps and tools used by the Company to analyze the distribution system and determine grid needs required to serve load growth and safely interconnect DER while maintaining power quality and reliability for all customers.

The Process is comprised of four stages: forecast, analysis, solution options, and evaluation.

1. **Forecast Stage**: Develop circuit-level forecasts based on the corporate demand forecast.
2. **Analysis Stage**: Determine the adequacy of the distribution system.
3. **Solution Options Stage**: Identify the grid needs requirements.
4. **Evaluation Stage**: Evaluation of solutions.

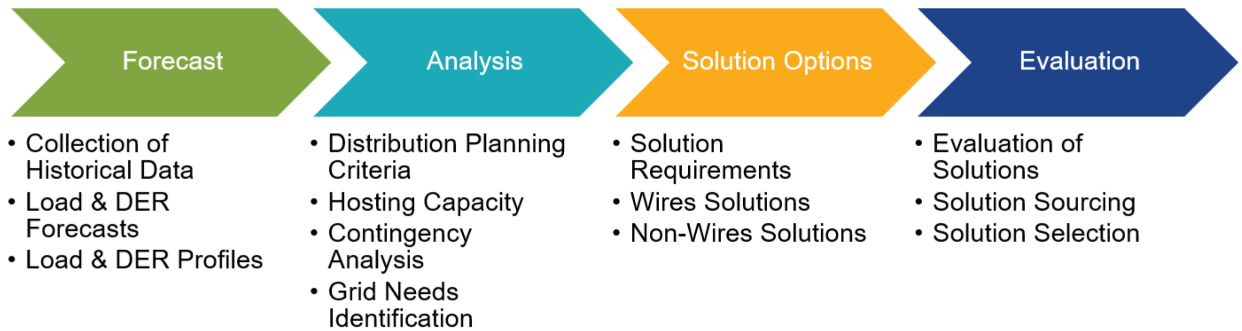

Figure 1: Stages of the Distribution Planning Process

This Distribution Planning Process is incorporated into the IGP process as it uses the corporate forecasts that include planned electrical demand and DER developed through IGP as an input to the distribution planning analyses to identify distribution grid needs. These distribution grid needs are then used as an input into the IGP process which will select portfolios of solutions to address resource, transmission, and distribution needs. The figure below shows how the Distribution Planning Process (see orange box) is performed in parallel which then converges with other identified steps in the IGP Process.

Figure 2: Distribution Planning Process and IGP Process[9]

This document focuses on hosting capacity grid needs identified for the next five years (year 2021 through 2025) driven by the forecasted DER growth on distribution circuits based on forecast sensitivities provided in the August Update.

As discussed in the August Update, various forecast sensitivities and scenarios were developed to address forecasting uncertainty. Three scenarios were selected from the August Update to provide a bookend approach to demonstrate the range of possible DER adoption and are summarized in the following table.[10]

[9] Hawaiian Electric, Presentation to IGP Stakeholder Technical Working Group, June 17, 2021.

[10] *See* Hawaiian Electric Revision to Updated and Revised Inputs and Assumptions filed on August 19, 2021 in Docket No 2018-0165. Table 6-3.

Table 1-1. DER Scenarios from August 2021 Update

No.	*Modeling Case*	*DER Forecast*
1	*Base*	*Base Forecast*
2	*High Load Customer Technology Adoption Bookend*	*Low Forecast*
3	*Low Load Customer Technology Adoption Bookend*	*High Forecast*

Hosting Capacity Grid Needs

The overall process and methodology, using modeling tools such as LoadSEER and Synergi,[11] to develop the grid needs driven by hosting capacity is provided herein. Since this report addresses the hosting capacity grid needs specifically, the distribution planning process figure discussed at the recent Stakeholder Technical Working Group meeting in June 2021[12] was streamlined to show details related only to this analysis and is shown in Figure 3. Potential wires and non-wires alternative ("NWA") solutions opportunities using the Non-Wires Opportunity Evaluation Methodology Report[13] will be evaluated later as part of the IGP process.

[11] *See* Hawaiian Electric, *Distribution Planning Methodology*, June 2020 for an overview of the LoadSEER and Synergi models.

[12] *See* https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/20210617_presentation_slides_igp_stakeholder.pdf at slide 20.

[13] *See* https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/distribution_planning/20200602_dpwg_non_wires_opportunity_evaluation_methodology.pdf

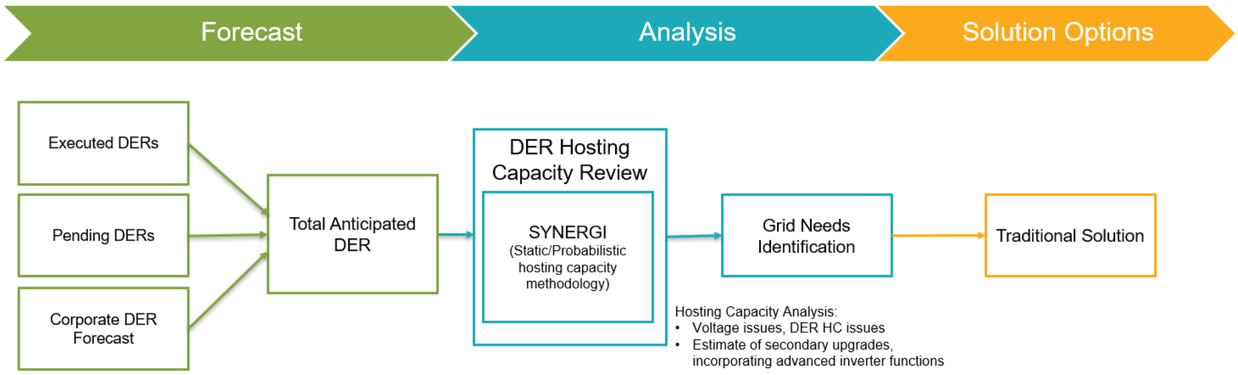

Figure 3: Hosting Capacity Grid Needs Identification Stages

The distribution planning criteria is used to establish circuit-level hosting capacity which is a circuit's ability to accommodate or host DERs to an identified kilowatt (kW) amount based on steady state load flow analyses. The methodology used to develop these hosting capacity numbers is geared towards analyzing DER growth due to small systems distributed on a circuit. Single large DER interconnections are typically evaluated on a case-by-case basis because their impact on the circuit largely depends on its generating capacity and location. In other words, circuit-level hosting capacity is the maximum aggregate kW amount of small scale DERs a circuit can host before any thermal or voltage violations occur.[14] This hosting capacity kW is utilized to identify the circuits with a grid need when the forecasted DER reaches this identified amount.

The following steps are used to identify circuits with hosting capacity violations in the next five years based on the current market DER forecast:

1. Determine the annual anticipated DER (kW) by circuit.
2. Screen circuits for analysis.
3. Perform substation transformer and circuit-level hosting capacity analysis.
4. Identify grid needs and solution options.

Throughout the year, Hawaiian Electric reviews and processes DER applications. In accordance with the Initial Technical Review ("ITR") process outlined in Rule 14H, the hosting capacity screen is one step in the overall interconnection technical review and addresses several screens outlined in Rule 14H.

[14] Hawaiian Electric, *Distribution Planning Methodology* June 2020, at 12.

2 Total Anticipated DER By Circuit

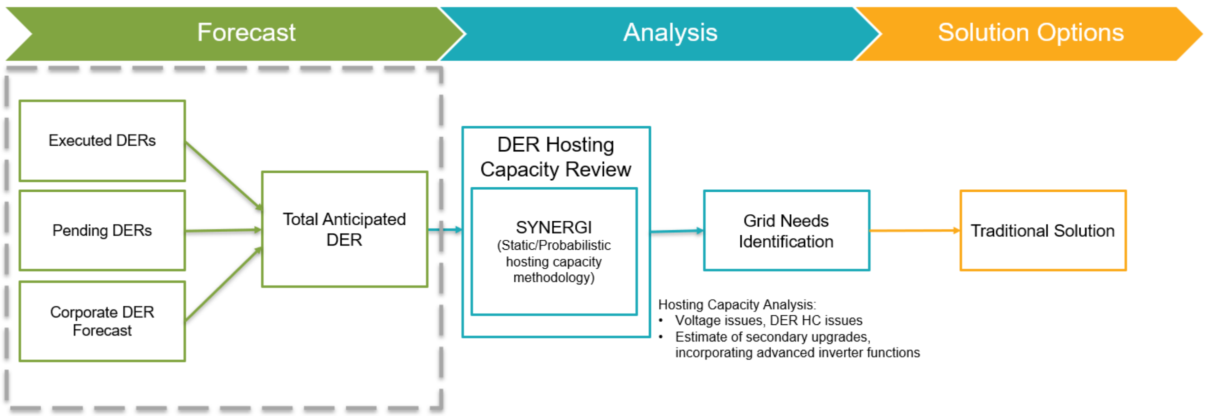

Figure 4: Forecast Stage of the Distribution Planning Process

This section describes the first step used to identify hosting capacity driven distribution grid needs:

1. **Determine the total anticipated DER (kW) by circuit.**
2. Screen circuits for analysis.
3. Perform substation transformer and circuit-level hosting capacity analysis.
4. Identify grid needs and solution options.

The total anticipated DER for a circuit is calculated by adding together the aggregate executed DER on that circuit and the forecasted DER growth for that circuit. The two components of this calculation are explained in the following sections.

$$Total\ Anticipated\ DER = Aggregated\ Executed\ DER + Adjusted\ DER\ Growth$$

The steps described in this section to determine the total anticipated DER by circuit were repeated for each of the DER forecasts: base, low, and high forecast.

2.1 AGGREGATE EXECUTED DER

The first step is to identify the existing DER on the circuits. Executed DER at the beginning of the study period is aggregated by total program size (kW) by circuit.[15] The programs included are:

- Net Energy Metering ("NEM")
- Feed-In Tariff ("FIT")
- Customer Grid Supply ("CGS")
- Customer Self-Supply ("CSS")
- Customer Grid Supply Plus ("GSP")
- Smart Export ("ISE")
- Net Energy Metering Plus ("NEM Plus" or "NMP")
- Standard Interconnection Agreement ("SIA")
- Community-Based Renewable Energy ("CBRE") Phase 1
- Power Purchase Agreement ("PPA")

For purposes of this hosting capacity analysis, battery energy storage capacity is not included in the aggregated DER values as it is assumed that energy storage systems will not export during the day.

2.2 ADJUSTED DER GROWTH BY CIRCUIT

The corporate demand forecast is provided at the system level, meaning there is one forecast for each island, and is built with separate layers such as underlying load, DER, energy efficiency ("EE"), and electric vehicles ("EV"). To perform the distribution planning hosting capacity analyses that typically occur at the circuit-level, the forecasted DER growth by feeder is determined based on the corporate DER forecast. Adjustments to the forecasted DER growth are made to account for any DER not captured, such as CBRE Phase 2 small projects, and explained in the following sections. The adjusted DER growth is then added to the aggregated executed DER to get the total anticipated DER by circuit used during the hosting capacity assessment in the Analysis stage.

The forecasted DER growth by feeder is derived from the corporate DER forecasts[16] using LoadSEER when available. Currently, LoadSEER models are available only for O'ahu with plans

[15] Executed programs as of December 31, 2020 are included.

[16] The DER forecasts (DER growth) by island are provided in Excel workbooks. See Appendix A:.

for implementation in the middle of 2022 on the islands of Maui and Hawaiʻi Island[17]. Since LoadSEER was recently adopted by the Company to create circuit-level forecasts, models for all islands are not fully built or complete to implement LoadSEER for this process. For all other islands, the forecasted DER growth is developed by allocating an island's corporate DER forecast proportional to the amount of executed DER on each circuit as a percentage of total executed DER on that island. In summary, the forecasted DER growth by year by circuit is determined using one of the following methods:

1. DER forecast allocation in LoadSEER.
2. DER forecast allocation based on existing DER.

Adjustments are also made to the forecasted DER growth by feeder to account for pending known large projects such as CBRE Phase 1, FIT, and large SIA (>250kW) projects. Because size and location of these projects are already known, they are added to the respective circuits in the estimated year of execution to get the adjusted DER growth by feeder. [18]

$$Forecasted\ DER\ Growth = Corporate\ DER\ Forecast + Adjustments$$ [19]

$$Adjusted\ DER\ Growth = Forecasted\ DER\ Growth + Large\ Project\ Adjustments$$ [20]

2.2.1 DER Forecast Allocation in LoadSEER

LoadSEER is an electric load forecasting software that creates circuit-level forecasts by combining historical SCADA and weather data along with forecasted new load, DER, EV, and EE spatially allocated throughout the system. LoadSEER spatially allocates these layers at the distribution level through an agent-based simulation that determines the likelihood (i.e., propensity score) that each of these types will be adopted at each service point. This process refines the system level forecast and provides location information such as customer consumption, historical DER adoption, census tract data, among others, with circuit-level forecasts. LoadSEER constrains the total amount that gets allocated for each of these layers by an incremental system level limit for each layer. The system level constraint is based on the corporate DER forecast. The resulting DER forecast allocation provides the feeder-level forecasted DER growth that is needed to calculate the adjusted DER forecast and thus the total anticipated DER by feeder.

The corporate DER forecast includes NEM, CGS, CSS, GSP, ISE, NMP, SIA, and a future program. Adjustments are made to the corporate DER forecast to account for the CBRE Phase

[17] The implementation of LoadSEER for the neighbor islands is targeted for middle of 2022 as reported in Exhibit 2 of Hawaiian Electric Companies' Quarterly DER Technical Report filed on September 30, 2021 in Docket No. 2019-0323.

[18] The DER growth by feeder (circuit) are provided in Excel workbooks. See Appendix A:.

[19] Adjustment for CBRE Phase 2 small projects.

[20] Large project adjustments include CBRE Phase 1, FIT, and large SIA (> 250 kW).

2 small projects program as well as pending CBRE Phase 1 and large (>250kW) SIA projects. For this update, the amount of CBRE Phase 2 small projects was revised to 30 MW[21] to be consistent with the 30 MW small project capacity described in the latest Order.[22] This 30MW of CBRE Phase 2 small projects were included by adding 6 MW per year to the corporate DER forecast. This was done for each scenario: Base, Low, and High. This amount is divided into residential and commercial customer types and is used as the system level DER limit for the spatial allocation in LoadSEER. LoadSEER can consider separate residential and commercial DER profiles when building feeder-level forecasts which will be important for the location-based forecasts provided in the Location-Based Forecasts for Distribution Grid Needs included with this filing. However, the residential/commercial split was not necessary for this hosting capacity grid needs analysis.

The resulting DER forecast allocation is then adjusted by adding pending CBRE Phase 1 and large SIA projects. Because the project size and location of these pending projects are already known, these adjustments were added to the individual feeder forecasted DER growth to produce the adjusted DER by feeder. The adjusted DER forecast is added to the aggregate executed DER to produce the total anticipated DER that is used in the Analysis stage.

In summary, the steps to determine the total anticipated DER by circuit by year are:

1. Starting with the corporate DER forecast, add 30 MW for CBRE Phase 2 small projects.
2. Run spatial allocation in LoadSEER to derive the forecasted DER growth by year by circuit.
3. Add pending large projects to construct adjusted DER by year by circuit.
4. Add aggregate executed DER to get the total anticipated DER.

2.2.2 DER Forecast Allocation Based on Existing DER

Since LoadSEER models are unavailable for Hawai'i Island and Maui County, a different method for the DER forecast allocation was required. This method involves allocating a system level amount proportional to the amount of executed DER in selected programs[23] on each circuit.

Similar to O'ahu, the corporate DER forecasts for Hawai'i Island and Maui County need to be adjusted for CBRE Phase 2 small projects and pending CBRE Phase 1 and FIT projects to get the system level amounts to allocate. The different CBRE Phase 2 small projects program cap

[21] The August 3, 2021 filing assumed 40 MW of CBRE Phase 2 small projects.

[22] *See* Order No. 37879 issued on July 27, 2021 in Docket No. 2015-0389, Approving the March 30 CBRE Filings, with Modifications.

[23] Selected programs include NEM, CGS, CSS, GSP, ISE, NMP, and SIA.

for each island is considered in the calculation of the adjusted DER forecast. The CBRE Phase 2 small projects added are consistent with the capacities described in the latest Order.[24]

The proportional amount that determines the allocation is calculated as the executed DER in selected programs on a feeder as a percentage of the total system executed DER in those same selected programs. The executed FIT and PPA projects are removed from the aggregate executed DER for each feeder as determined above in Section 2.1 to get the amount of executed DER in the selected programs for each feeder. Including only these smaller type programs in this calculation focuses the forecasted DER growth on increasing residential DER systems. The executed FIT and PPA projects were removed because these are typically larger projects that would slant the results of this calculation toward these circuits where small DER may not be as likely to be adopted.

Next, the amount of executed DER in the selected programs on that circuit is expressed as a percentage of the total executed DER in those selected programs on the respective island. The incremental system level DER limit based on the corporate forecast and CBRE Phase 2 small projects is then allocated to the circuit based on this percentage. For example, if the executed DER in the selected programs on a circuit is 5% of the total executed DER on that island, 5% of the adjusted DER forecast will be allocated to that circuit. Pending CBRE Phase 1 and FIT projects are added to the resulting feeder-level forecasted DER growth to get the adjusted DER growth. The adjusted DER growth is added to the aggregate executed DER to produce the total anticipated DER that is used in the Analysis stage.

In summary, the steps to get the total anticipated DER by circuit by year are:

1. Starting with the corporate DER forecast, add CBRE Phase 2 small projects.

2. Determine forecasted DER growth by year by circuit.
    a. Remove the executed FIT and PPA projects from the aggregate executed DER for each feeder to get the amount of executed DER in the selected programs on each feeder.

    b. Calculate the executed DER in the selected programs on each circuit as a percentage of total executed DER in those selected programs on that island.

$$\%\ Circuit\ Allocation_{DER} = \frac{Executed\ DER\ in\ selected\ programs\ on\ Circuit}{Total\ Executed\ DER\ in\ selected\ programs}$$

[24] *See* Order No. 37879 issued on July 27, 2021 in Docket No. 2015-0389, Approving the March 30 CBRE Filings, with Modifications at 33.

   c. Allocate the incremental system level DER limit for each year (year 2021 through 2025) among circuits based on the percentage calculated in the previous step.

3. Add pending large projects to construct adjusted DER by year by circuit.

$$\text{DER Forecast Allocation} = (\%\ Circuit\ Allocation_{DER}) \times (Incremental\ system\ level\ DER\ limit)$$

4. Add aggregate executed DER to get the total anticipated DER.

3 Analysis

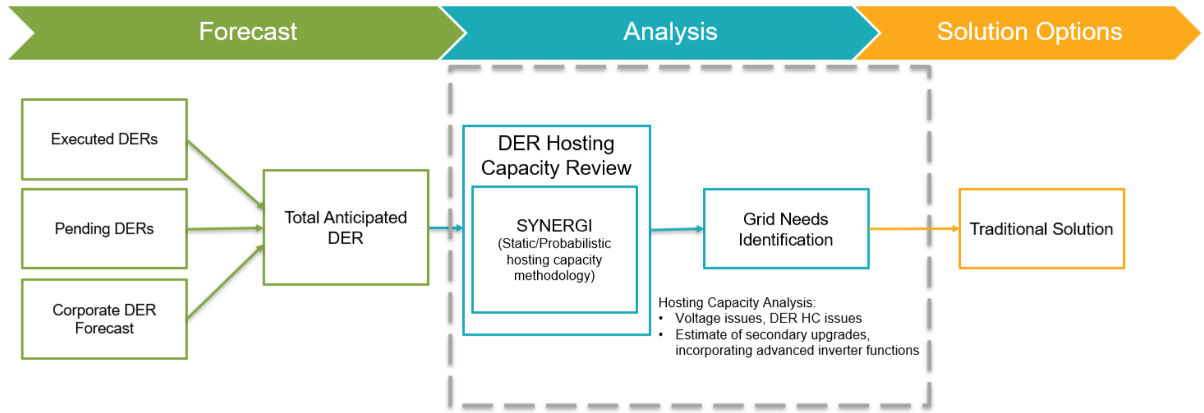

Figure 5. Analysis Stage of the Distribution Planning Process

This section describes steps 2 and 3 used to identify hosting capacity driven distribution grid needs:

1. Determine the annual anticipated DER (kW) by circuit.
2. **Screen circuits for analysis.**
3. **Perform substation transformer and circuit-level hosting capacity analysis.**
4. Identify grid needs and solution options.

The steps described in this section to determine the total anticipated DER by circuit were repeated for each of the DER forecasts: base, low, and high forecast. A circuit-level hosting capacity assessment is used to determine if a circuit can accommodate the anticipated DER in the study period. A summary of the circuit selection and hosting capacity analysis process is shown in the figure below.

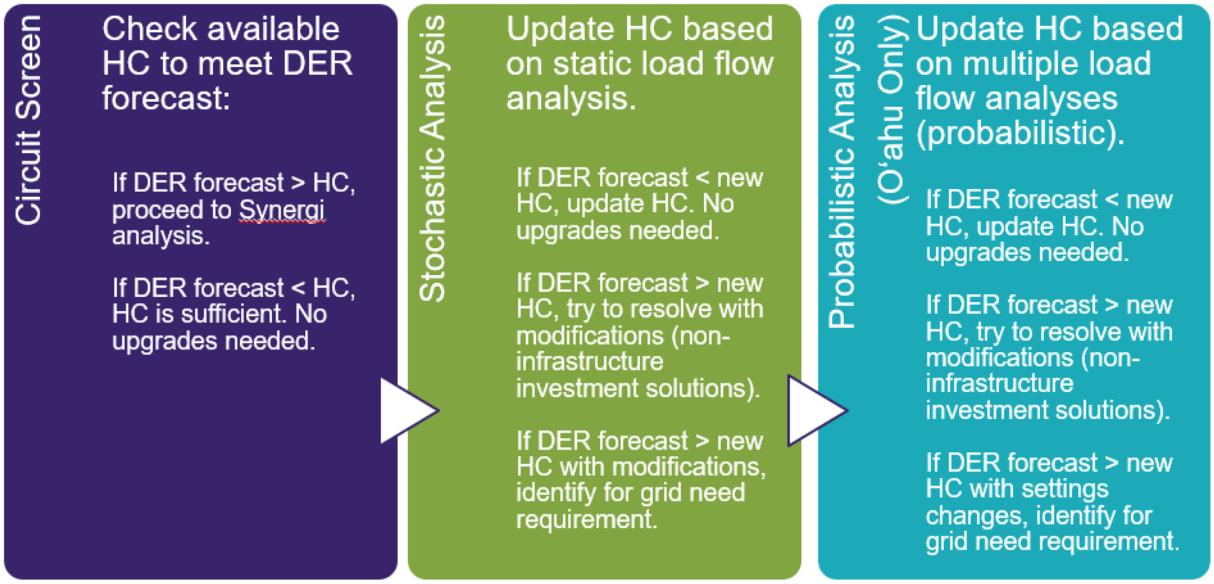

Figure 6. Summary of Hosting Capacity Analysis

3.1 SCREEN CIRCUITS FOR ANALYSIS

The Company utilizes a multi-step screening process, which increases in complexity (i.e., time and resources) to further assess the circuit's ability to host the forecasted DER. Circuits are screened and selected by comparing the anticipated DER by circuit described in Section 2 with the current hosting capacity to determine if the current circuit hosting capacity can accommodate the level of total anticipated DER in the last year of the study period (year 2025). If a circuit is unable to accommodate the anticipated DER in year 2025 with its current hosting capacity, the circuit is selected for further analysis where the hosting capacity is reassessed.

In summary, circuits are selected for further analysis if:

- Total anticipated DER in the year 2025 is greater than the current hosting capacity.

If the total anticipated DER in year 2025 is less than the current hosting capacity, then there are no grid needs and no further analysis is required.

Using this selection screening criteria, a total of 185 circuits using the high DER forecast, 111 circuits using the base DER forecast, and 103 circuits using the low DER forecast are selected for further analysis. A summary of the circuits selected by island and forecast is shown in the table below. Company-owned radial distribution circuits are included in the hosting capacity analysis. Dedicated and network (non-radial) circuits are not included in the tables.

Table 3-1: Summary of Circuit Selection Screening

Island	Total Circuits	Existing Hosting Capacity Satisfies Need (Analysis Not Required)			Total Anticipated DER in 2025 > Hosting Capacity (Analysis Required)		
		Low	Base	High	Low	Base	High
O‘ahu	384	357	350	303	27	34	81
Hawai‘i Island	137	95	95	76	42	42	61
Maui Island	88	59	58	52	29	30	36
Lana‘i	3	1	1	1	2	2	2
Moloka‘i	8	5	5	3	3	3	5
Total (All Islands)	620	517	509	435	103	111	185

3.2 HOSTING CAPACITY ASSESSMENT

If a circuit is selected for further analysis, the circuit-level hosting capacity is reassessed and updated using one or both of the following methods:

1. Stochastic hosting capacity methodology.
2. Probabilistic hosting capacity methodology.

Both methods use the Synergi load flow software to simulate DER growth to determine the circuit hosting capacity for DER.

A stochastic hosting capacity analysis is done first. This method analyzes specific points in time that envelope the circuit's characteristics. This method is a much quicker analysis compared to the probabilistic method which is computationally intensive performing the analysis over a variation of DER growth scenarios utilizing time series data. The updated hosting capacity is then compared to the amount of anticipated DER in year 2025. If the revised hosting capacity is greater than the amount of anticipated DER in year 2025, there are no grid needs and no further analysis is required.

If the updated hosting capacity is less than the anticipated DER in year 2025, a subsequent hosting capacity evaluation may be performed using the probabilistic hosting capacity for circuits with available models. If the probabilistic hosting capacity is higher than the anticipated DER in year 2025, the probabilistic hosting capacity will become the updated hosting capacity.

If the stochastic hosting capacity or probabilistic hosting capacity result is less than the anticipated DER in year 2025, the circuit is identified as requiring solution options and further described in Section 3.5.

3.3 STOCHASTIC HOSTING CAPACITY METHODOLOGY (PV GROW)

Initially, the hosting capacity is reassessed using Synergi's built-in PV Grow function. PV Grow stochastically adds PV generators to the selected feeders in proportion to customer load. Generators are added to the feeders until an exception, such as a voltage or thermal violation, occurs. Once an exception is hit, the amount of PV (kW) added plus existing becomes the feeder hosting capacity.

In this analysis, the hosting capacity is determined for a snapshot in time, specifically, the hour representing the daytime minimum load ("DML") and does not account for the capacity available at other hours which may vary due to load variations throughout the day. To perform this analysis, the following circuit data is input into Synergi:

- Minimum gross demand (kVA and kW) and date and time of occurrence.
- Peak demand (kVA and kW) and date and time of occurrence.

A load flow is simulated in conjunction with the PV Grow analysis to assess daytime minimum load conditions and hosting capacity for the base case. If there are base case violations, such as high and low voltages or thermal overloads, or the hosting capacity is lower than the anticipated DER, then simple mitigation solutions such as modifications to existing equipment (i.e. modifications that do not require infrastructure investments) will be applied and simulated again. These modifications may include substation LTC setting changes, switching, or phase balancing. If a solution option involves substation LTC setting changes then a load flow is also simulated using the peak demand case to verify no violations will occur with the new settings. This process is repeated until a solution option is found that results in no violations in both the DML and peak cases, and hosting capacity accommodates the anticipated DER. The results from the PV Grow analysis is the updated hosting capacity.

If no solution can be found using the PV Grow analysis, then additional analysis may be performed using the probabilistic hosting capacity methodology described below or the circuit is identified as requiring a grid need. Results of the PV Grow analysis are shown in Table 2.

3.4 PROBABILISTIC HOSTING CAPACITY METHODOLOGY

The probabilistic hosting capacity is an updated methodology developed in collaboration with the Electric Power Research Institute ("EPRI") that resulted from discussions with stakeholders to improve the hosting capacity methodology.[25] In contrast to the initial hosting capacity analysis, using the Synergi PV Grow function, that models a single DER growth scenario for a single hour, this updated method models 576 hourly profiles. Probabilistic modeling techniques are applied to calculate hosting capacity under multiple DER growth scenarios to provide a more robust hosting capacity and is described in further detail in the *Distribution Planning Methodology*. [26]

The hosting capacity is determined by creating a base case of the circuit model and utilizing circuit-level forecasts generated from LoadSEER, solar irradiance profiles and the scripts developed by EPRI in Synergi to execute the probabilistic hosting capacity analysis. The analysis produces a feeder hosting capacity profile by statistically analyzing feeder exceptions found at different DER penetration levels across multiple DER growth scenarios. Therefore, these results are expected to be a more precise representation of feeder hosting capacity thresholds than results from the PV Grow analysis.

Similar to the stochastic hosting capacity analysis, the probabilistic hosting capacity results are compared to the total anticipated DER in year 2025. If the probabilistic hosting capacity is higher than the anticipated DER, the results become the updated hosting capacity. If the probabilistic hosting capacity is lower than the anticipated DER, simple non-infrastructure investment solutions may be considered and reanalyzed. If the probabilistic hosting capacity is still lower than the anticipated DER, the circuit is identified as requiring a grid need. Results of the probabilistic hosting capacity analysis for O'ahu are combined with the results from Section 3.3 and are shown in Table 2.

[25] *See* Hawaiian Electric Companies' Initial Statement of Position on Deferred Issues and Technical Track Issues issued on August 14, 2017 in Docket No. 2014-0192.

[26] Hawaiian Electric, *Distribution Planning Methodology,* June 2020 at 13-17.

3.5 HOSTING CAPACITY RESULTS

The hosting capacity analysis results are grouped into the following categories by circuit:

- **Existing Hosting Capacity Satisfies Need**: Existing hosting capacity can accommodate the total anticipated DER in year 2025. No grid needs are required.
- **Updated Hosting Capacity (Without Modifications) Satisfies Need:** Updated hosting capacity can accommodate the total anticipated DER in year 2025. No grid needs are required.
- **Updated Hosting Capacity (With Modifications) Satisfies Need:** Updated hosting capacity along with modifications that do not require infrastructure investments can accommodate the total anticipated DER in year 2025.
- **Solution Option Required:** Updated hosting capacity is unable to accommodate the total anticipated DER in year 2025. Grid need identified.

A summary of the hosting capacity assessment by island is shown below using each forecast. The results for O'ahu include results from both the stochastic and probabilistic analyses. For all other islands, the results are from the PV Grow analysis. Hosting capacity results by circuit by island are provided in the workbooks described in Appendix A:.

Table 3-2: Summary of Hosting Capacity Results

Island	Forecast	Grid Needs Not Required		Grid Needs Required		Total Circuits
		Existing Hosting Capacity Satisfies Need	Updated HC (w/o modifications) Satisfies Need	Updated HC (w/ modifications) Satisfies Need	Solution Option Required	
O'ahu	High	303	49	15	17	384
	Base	350	22	6	6	384
	Low	357	17	5	5	384
Hawai'i Island	High	76	27	32	2	137
	Base	95	21	19	2	137
	Low	95	21	19	2	137
Maui Island	High	52	16	13	7	88
	Base	58	15	12	3	88
	Low	59	15	11	3	88
Lana'i	High	1	0	0	2	3
	Base	1	0	0	2	3
	Low	1	0	0	2	3
Moloka'i	High	3	0	0	5	8
	Base	5	0	0	3	8
	Low	5	0	0	3	8
Total (All Islands)	High	435	92	60	33	620
	Base	509	58	37	16	620
	Low	517	53	35	15	620

3.5.1 High DER Forecast

Of the 620 circuits assessed, 435 circuits are able to accommodate the total anticipated DER in 2025 with the existing hosting capacity using the high DER forecast. In addition, 92 circuits are able to accommodate the anticipated DER through an updated hosting capacity without grid needs. The remaining 93 circuits are identified as requiring grid needs and are discussed in the Section 4.

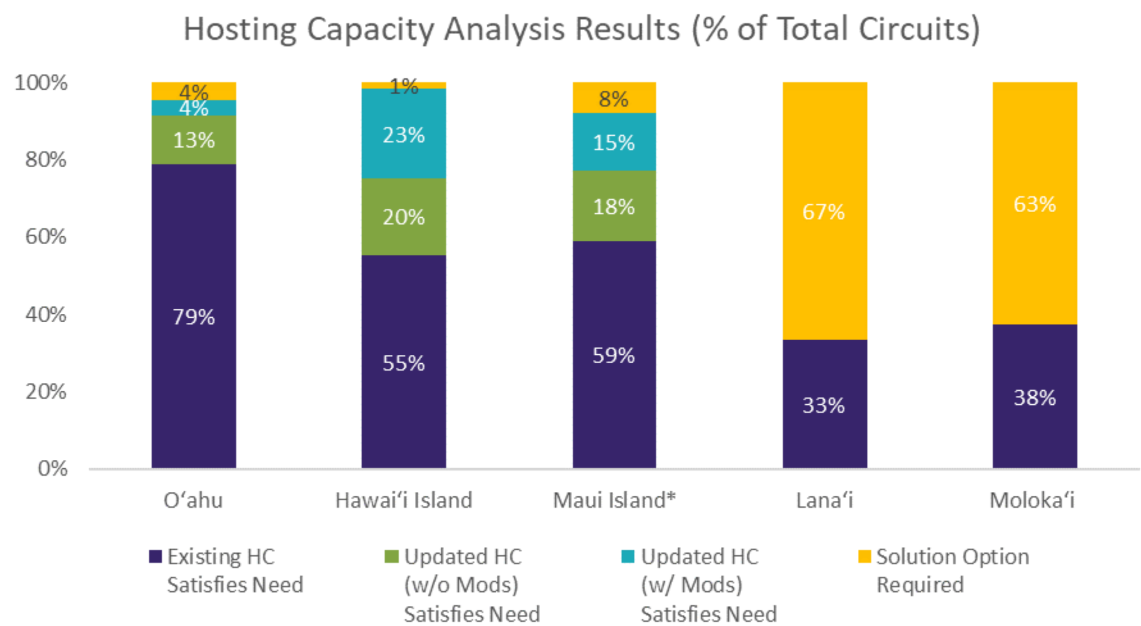

Figure 7: Summary of Hosting Capacity Results (% of Total Circuits) Using the High DER Forecast[27]

[27] Total percentage does not equal to 100 % due to rounding.

3.5.2 Base DER Forecast

Of the 620 circuits assessed, 509 circuits are able to accommodate the total anticipated DER in 2025 with the existing hosting capacity using the base DER forecast. In addition, 58 circuits are able to accommodate the anticipated DER through an updated hosting capacity without grid needs. The remaining 53 circuits are identified as requiring grid needs and are discussed in the Section 4.

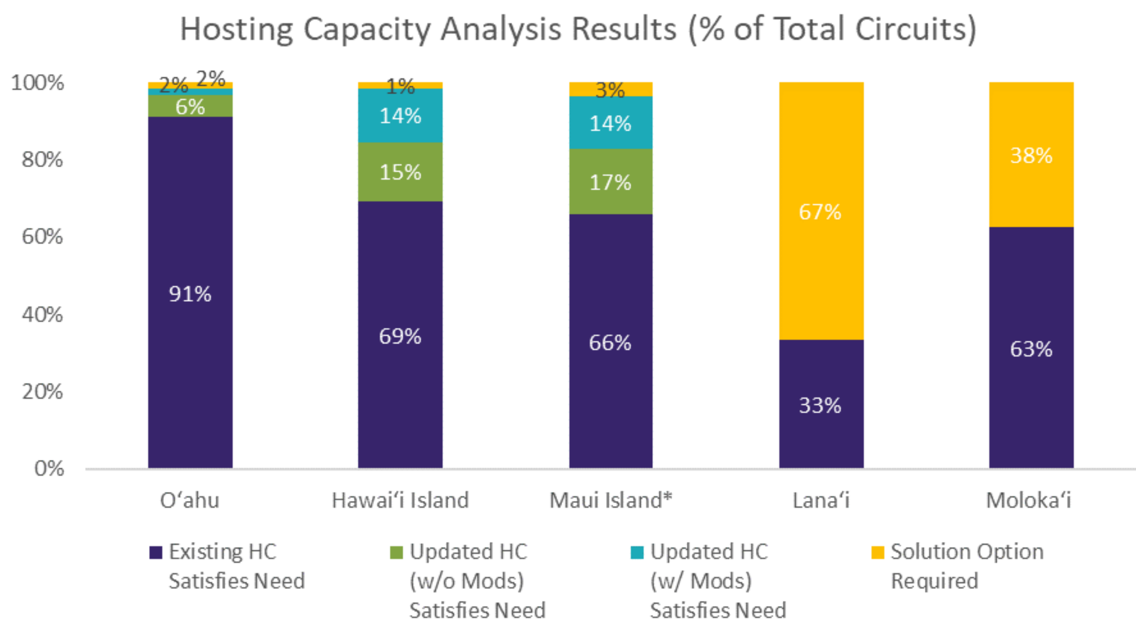

Figure 8: Summary of Hosting Capacity Results (% of Total Circuits) Using the Base DER Forecast[28]

[28] Total percentage does not equal to 100 % due to rounding.

3.5.3 Low DER Forecast

Of the 620 circuits assessed, 517 circuits are able to accommodate the total anticipated DER in 2025 with the existing hosting capacity using the base DER forecast. In addition, 53 circuits are able to accommodate the anticipated DER through an updated hosting capacity without grid needs. The remaining 50 circuits are identified as requiring grid needs and are discussed in the Section 4.

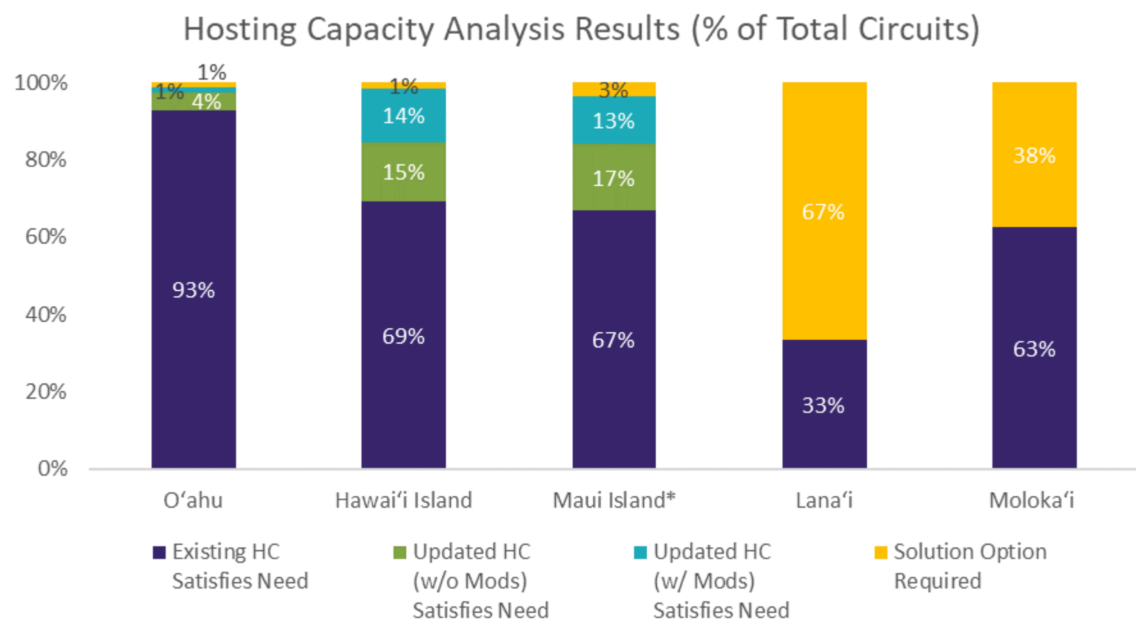

Figure 9: Summary of Hosting Capacity Results (% of Total Circuits) Using the Low DER Forecast[29]

[29] Total percentage does not equal to 100 % due to rounding.

4 Grid Needs

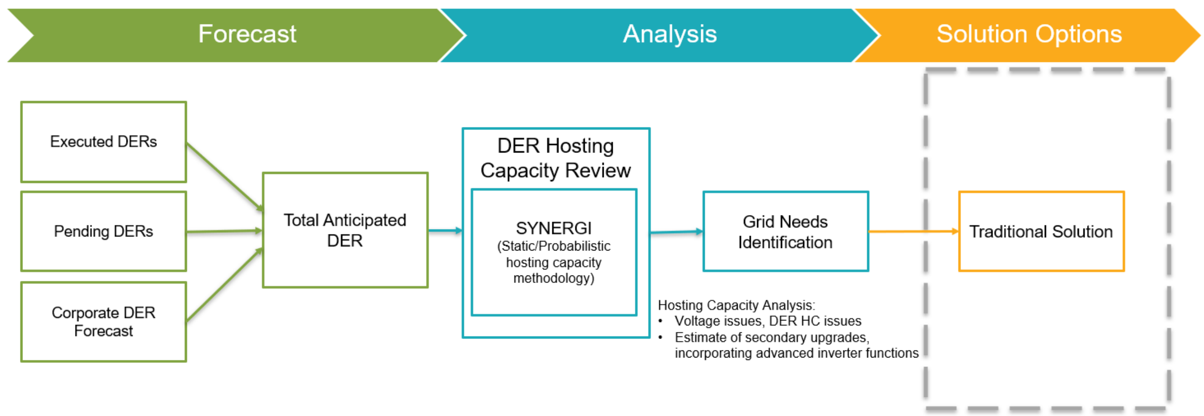

Figure 10: Solution Options Stage of the Distribution Planning Process

This section describes the last step to identify distribution grid needs:

1. Determine the annual anticipated DER (kW) by circuit.
2. Screen circuits for analysis.
3. Perform substation transformer and circuit-level hosting capacity analysis.
4. **Identify grid needs and solution options.**

Grid needs are identified for circuits requiring mitigation resulting from the hosting capacity analysis described in Section 3. A circuit is flagged as requiring mitigation if the hosting capacity is unable to accommodate the anticipated DER in 2025. For these circuits, the annual anticipated DER for each year for the study period (year 2021 through 2025) is compared to the hosting capacity. The earliest year that the anticipated DER is greater than the hosting capacity is identified as the year in which mitigation is required (i.e. operating date). A comparison of the annual anticipated DER to updated hosting capacity by circuit for each island is provided in the workbooks described in Appendix A:.[30]

[30] Workbooks are available on the Company website at: https://www.hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning/stakeholder-engagement/key-stakeholder-documents

As described in the *Distribution Planning Methodology*, a traditional solution will be defined for each grid need identified and include:[31]

- **Substation**: Transformer asset identification
- **Circuit**: Feeder asset identification
- **Distribution Service Required**: Hosting Capacity, Distribution Capacity or Distribution Reliability (Back-Tie) Service
- **Primary Driver of Grid Need**: Defines whether the identified grid need is primarily driven by DER growth, demand growth, other factor(s), or a combination of factors
- **Violation Type**: Thermal and/or voltage violation that triggers the grid need
- **Operating Date**: The date at which traditional infrastructure must be constructed and energized, in advance of the forecasted grid need to maintain safety and reliability
- **Traditional Solution**: Traditional solution identified for mitigation (Solution Options)
- **Cost Estimate**: Estimated cost to provide traditional solution identified.

The hosting capacity grid needs assessment tables shown in the following sections are simplified and do not include all the fields defined above as some are not applicable for the hosting capacity grid needs or the fields are consistent for all islands for all years. The following fields are applicable to all islands and are not replicated in the tables in the subsequent sections:

- Distribution Service Required: Increase circuit hosting capacity
- Primary Driver of Grid Need: DER growth

For the circuits identified in Section 3.5 as requiring grid needs, some have solution options which can be addressed through modifications to existing equipment while others require infrastructure investments. For the solutions that do not require infrastructure investments (non-infrastructure investments), the cost to implement is minimal and therefore not provided in the following sections. These modifications include:

- LTC Settings Change: Adjusting the load tap changer ("LTC") on an existing transformer or regulator

[31] Hawaiian Electric, *Distribution Planning Methodology*, June 2020 at 20.

Circuits requiring infrastructure investments may include:

- Circuit phase balancing
- Dynamic LTC[32]
- New line voltage regulator
- New tie switch
- Reconductoring
- Step-down transformer upgrade

For these circuits, high-level cost estimates based on unit cost information from previous similar projects are provided.

A summary of the circuits requiring grid needs by solution type is shown below for each scenario. The number of circuits requiring grid needs is highest using the high DER forecast and decreases further using the base and low DER forecasts, respectively. Some circuits may require grid needs in two or more scenarios. Grid needs by circuit by scenario are provided in the following sections.

[32] Dynamic LTC is the ability to autonomously adjust the LTC setting of a transformer throughout the day based on triggers such as time of day or irradiance.

Table 4-1: Grid Needs Assessment Summary

Island	Forecast	Solution Option		Total Circuits
		Non-Infrastructure Investments[33]	Infrastructure Investments	
O'ahu	High	15	17	32
	Base	6	6	12
	Low	5	5	10
Hawai'i Island	High	32	2	34
	Base	19	2	21
	Low	19	2	21
Maui Island	High	13	7	20
	Base	12	3	15
	Low	11	3	14
Lana'i	High	–	2	2
	Base	–	2	2
	Low	–	2	2
Moloka'i	High	–	5	5
	Base	–	3	3
	Low	–	3	3
Total (All Islands)	High	60	33	93
	Base	37	16	53
	Low	35	15	50

[33] LTC settings changes only.

4.1 HIGH DER FORECAST

Using the high DER forecast, of the 93 circuits identified as requiring grid needs in Section 3.5.1, 60 circuits have solution options that can be addressed through minimal infrastructure investments (e.g. LTC settings change) and 33 circuits require infrastructure investments.

Table 4-2: Grid Needs Assessment Summary Using the High DER Forecast

Island	Total Circuits[34]	Violation Type[35]		Solution Option	
		Voltage	Conductor Overload	Non-Infrastructure Investments[36]	Infrastructure Investments
O‘ahu	32	31	5	15	17
Hawai‘i Island	34	34	-	32	2
Maui Island	20	19	2	13	7
Lana‘i	2	2	-	-	2
Moloka‘i	5	5	-	-	5
Total (All Islands)	93	91	7	60	33

The grid needs assessment by island by circuit are detailed in the following tables.

O‘ahu

Table 4-3: O‘ahu Grid Needs Assessment Using the High DER Forecast

Substation	Circuit	Violation Type	Operating Date	Traditional Solution	Cost Estimate
AIEA 2	AIEA	Voltage	2022	LTC setting change	-
WAILUPE	AINA KOA	Voltage	2022	Circuit phase balancing	$14,400
KAMILOIKI	ANUU	Voltage	2023	LTC setting change	-
KAPAHULU 4	DIAMOND HEAD	Voltage	2022	LTC setting change	-

[34] "Total Circuits" represents the number of circuits that have grid needs requirements.

[35] Circuit totals by violation type do not match the total circuits column as some circuits have both voltage and conductor overload violations and are counted in both columns.

[36] LTC settings changes only.

Substation	Circuit	Violation Type	Operating Date	Traditional Solution	Cost Estimate
EWA BEACH 2	EWA BEACH 3	Voltage	2023	LTC setting change	-
EWA BEACH 2	EWA BEACH 4	Voltage	2023	LTC setting change	-
KAHALA 2 4KV	FARMERS RD	Voltage, conductor overloading	2023	Circuit phase balancing, Install two 3ph line regulators, Reconductoring	$605,191
WAIALUA 2	KAENA PT	Voltage	2023	LTC setting change	-
KAHALA 1 4KV	KAHALA	Voltage, conductor overloading	2022	Install 3ph line regulator, Reconductoring, new tie switch	$1,206,917
KEOLU 2	KAILUA HTS	Voltage	2025	LTC setting change	-
KALAMA 1 4KV	KAINALU	Voltage, conductor overloading	2021	Dynamic LTC, Install two 1ph line regulators, Reconductoring	$439,727
AIKAHI 1	KALAHEO	Voltage	2025	LTC setting change	-
WAIALUA 3	KAWAILOA	Voltage	2021	LTC setting change	-
KAHALA 2 4KV	KILAUEA 4KV	Voltage	2022	Circuit phase balancing and Install 3ph line regulator	$213,600
KAHALA 2 4KV	KOLOA	Voltage, conductor overloading	2024	Circuit phase balancing, Install 3ph line regulator, Reconductoring	$470,854
KUILIMA 2	KUILIMA 1	Voltage	2025	LTC setting change	-
WOODLAWN 2	LOWREY	Voltage	2023	Install two 1ph line regulators	$140,000
MAKAKILO 2	MAKAKILO 2	Voltage	2022	LTC setting change	-
PIIKOI 3	MANOA-PIIKOI	Voltage	2024	Circuit phase balancing	$3,600
MAKAHA 2	MAUKA	Voltage	2023	Circuit phase balancing	$3,600
MIKILUA 2	MIKILUA 3	Voltage	2023	Circuit phase balancing	$3,600

Substation	Circuit	Violation Type	Operating Date	Traditional Solution	Cost Estimate
MIKILUA 2	MIKILUA 4	Voltage, transformer overloading	2021	Step-down transformer upgrade	$68,000
MIKILUA 3	MIKILUA 5	Voltage	2023	Dynamic LTC	$154,000
KALAMA 1 4KV	ONEAWA	Voltage	2022	LTC setting change	-
PAUOA 1	PAUOA 2	Voltage	2023	Circuit phase balancing and partial 4kV-12kV conversion	$610,200
PIIKOI 4	PIIKOI 8	Conductor overloading	2022	Reconductoring	$270,000
AHI 2	PORTLOCK	Voltage	2024	LTC setting change	-
WAIALUA 3	WAIALUA	Voltage	2022	LTC setting change	-
WAILUPE	WAILUPE	Voltage	2023	Circuit phase balancing	$7,200
WAIMANALO BCH 1	WAIMANALO	Voltage	2025	Dynamic LTC	$154,000
WAIMEA 1	WAIMEA 2	Voltage	2024	LTC setting change	-
WAIALAE 1 4KV	WAI-WILHELMINA	Voltage	2025	Install two 1ph line regulators	$140,000

Hawaiʻi Island

Table 4-4: Hawaii Island Grid Needs Assessment Using the High DER Forecast

Substation	Circuit	Violation Type	Operating Date	Traditional Solution	Cost Estimate
Captain Cook	Captain Cook 12	Voltage	2025	LTC setting change	-
Halaula	Halaula 1	Voltage	2022	Install two 3ph line regulator	$420,000
Hawaiian Paradise Park 2	Hawaiian Paradise Park 13	Voltage	2021	LTC setting change	-
Hawaiian Paradise Park 2	Hawaiian Paradise Park 14	Voltage	2021	LTC setting change	-

Substation	Circuit	Violation Type	Operating Date	Traditional Solution	Cost Estimate
Honokaa 2	Honokaa 12	Voltage	2021	LTC setting change	–
Huehue	Huehue 11	Voltage	2024	LTC setting change	–
Kahaluu 1	Kahaluu 11	Voltage	2025	LTC setting change	–
Kaloko 2	Kaloko 13	Voltage	2025	LTC setting change	–
Kapua 1	Kapua 11	Voltage	2021	LTC setting change	–
Kauhale	Kauhale 11	Voltage	2021	LTC setting change	–
Kauhale	Kauhale 12	Voltage	2021	LTC setting change	–
Kaumana	Kaumana 11	Voltage	2025	LTC setting change	–
Kawaihae	Kawaihae 11	Voltage	2024	LTC setting change	–
Kawaihae	Kawaihae 12	Voltage	2025	LTC setting change	–
Keahole Airport	Keahole Airport 11	Voltage	2022	LTC setting change	–
Keahole Airport	Keahole Airport 12	Voltage	2025	LTC setting change	–
Keahole Airport	Keahole Airport 13	Voltage	2024	LTC setting change	–
Komohana 1	Komohana 12	Voltage	2021	LTC setting change	–
Kuakini 1	Kuakini 11	Voltage	2023	LTC setting change	–
Kurtistown	Kurtistown 12	Voltage	2021	LTC setting change	–
Laupahoehoe	Laupahoehoe 2	Voltage	2022	LTC setting change	–
Mauna Lani 2	Mauna Lani 14	Voltage	2021	LTC setting change	–
Namakani Paio	Namakani Paio	Voltage	2021	LTC setting change	–
Ookala	Ookala	Voltage	2021	LTC setting change	–
Orchid Isle	Orchid Isle 11	Voltage	2021	LTC setting change	–
Orchid Isle	Orchid Isle 12	Voltage	2021	LTC setting change	–
Paauilo	Paauilo 1	Voltage	2021	LTC setting change	–
Panaewa	Panaewa 12	Voltage	2021	LTC setting change	–
Puueo 2	Puueo 11	Voltage	2021	LTC setting change	–
Puueo 2	Puueo 12	Voltage	2021	LTC setting change	–

Substation	Circuit	Violation Type	Operating Date	Traditional Solution	Cost Estimate
Puuwaawaa	Puuwaawaa 11	Voltage	2021	Install 3ph line regulator	$210,000
Waikii	Waikii 12	Voltage	2021	LTC setting change	-
Waikoloa	Waikoloa 12	Voltage	2022	LTC setting change	-
Waipunahina	Waipunahina 11	Voltage	2022	LTC setting change	-

Maui Island

Table 4-5: Maui Island Grid Needs Assessment Using the High DER Forecast

Substation	Circuit	Violation Type	Operating Date	Traditional Solution	Cost Estimate
Huelo	Huelo 74A/Huelo	Voltage	2024	Install 1ph line regulator	$70,000
Kahului 4	Kahului 8/4048	Voltage	2024	LTC setting change	-
Kahului 5	Kahului 8/4049	Voltage	2021	LTC setting change	-
Kauhikoa	Kauhikoa 98/1295	Voltage	2025	LTC setting change	-
Kihei 4	Kihei 35/1515	Voltage	2023	Install 3ph line regulator	$210,000
Kuau	Kuau 73/4066	Voltage	2021	LTC setting change	-
Kuihelani	Kuihelani 209/1653	Voltage	2021	LTC setting change	-
Kuihelani	Kuihelani 209/1708	Voltage	2021	LTC setting change	-
Kula	Kula 13/1237	Voltage, conductor overloading	2021	Reconductor and Install two 3ph line regulators	$2,235,909
Kula	Kula 13/1238	Voltage	2023	LTC setting change	-
Lahaina 5	Lahaina 34/1398	Voltage	2021	Install 3ph line regulator	$210,000

Substation	Circuit	Violation Type	Operating Date	Traditional Solution	Cost Estimate
Makawao	Makawao 12/1236	Voltage	2023	LTC setting change	-
Onehee	Onehee 40/4055	Conductor overloading	2025	Reconductor	$560,000
Paia Mauka	Paia Mauka 93/4042	Voltage	2021	Circuit phase balancing	$14,400
Peahi	Peahi 94/1294	Voltage	2021	LTC setting change	-
Pukalani 1	Pukalani 17/1282	Voltage	2022	LTC setting change	-
Spreckelsville	Spreckelsville 92/4043	Voltage	2021	LTC setting change	-
Waiinu 3	Waiinu 36/1493	Voltage	2022	LTC setting change	-
Wailea 4	Wailea 25/1517	Voltage	2022	Circuit phase balancing	$14,400
Wailea 4	Wailea 25/1518	Voltage	2022	LTC setting change	-

Lana‘i

Table 4-6: Lanai Grid Needs Assessment Using the High DER Forecast

Substation	Circuit	Violation Type	Operating Date	Traditional Solution	Cost Estimate
Miki Basin	Miki Basin PP 302/1208	Voltage	2023	Install 3ph line regulator	$252,000
Miki Basin	Miki Basin PP 302/1210	Voltage	2022	Install 3ph line regulator	$252,000

Moloka'i

Table 4-7: Molokai Grid Needs Assessment Using the High DER Forecast

Substation	Circuit	Violation Type	Operating Date	Traditional Solution	Cost Estimate
Palaau	Palaau PP 81/105A	Voltage	2022	Install 3ph line regulator	$252,000
Palaau	Palaau PP 81/106B	Voltage	2023	Install 3ph line regulator	$252,000
Palaau	Palaau PP 81/109B	Voltage	2021	Install 3ph line regulator	$252,000
Palaau	Palaau PP 81/110B	Voltage	2021	Install 3ph line regulator	$252,000
Palaau	Palaau PP 81/111A	Voltage	2021	Install three 3ph line regulator	$756,000

4.2 BASE DER FORECAST

Using the base DER forecast, of the 53 circuits identified as requiring grid needs in Section 3.5.2, 37 circuits have solution options that can be addressed through minimal infrastructure investments (e.g. LTC settings change) and 16 circuits require infrastructure investments.

Table 4-8: Grid Needs Assessment Summary Using the Base DER Forecast

Island	Total Circuits[37]	Violation Type[38]		Solution Option	
		Voltage	Conductor Overload	Non-Infrastructure Investments[39]	Infrastructure Investments
O'ahu	12	11	1	6	6
Hawai'i Island	21	21	-	19	2
Maui Island	15	15	1	12	3

[37] "Total Circuits" represents the number of circuits that have grid needs requirements.

[38] Circuit totals by violation type do not match the total circuits column as some circuits have both voltage and conductor overload violations and are counted in both columns.

[39] LTC settings changes only.

Island	Total Circuits[37]	Violation Type[38]		Solution Option	
		Voltage	Conductor Overload	Non-Infrastructure Investments[39]	Infrastructure Investments
Lana‘i	2	2	–	–	2
Moloka‘i	3	3	–	–	3
Total (All Islands)	53	52	2	37	16

The grid needs assessment by island by circuit are detailed in the following tables.

O‘ahu

Table 4-9: O‘ahu Grid Needs Assessment Using the Base DER Forecast

Substation	Circuit	Violation Type	Operating Date	Traditional Solution	Cost Estimate
AIEA 2	AIEA	Voltage	2024	LTC setting change	–
WAILUPE	AINA KOA	Voltage	2023	Circuit phase balancing	$7,200
KAPAHULU 4	DIAMOND HEAD	Voltage	2024	LTC setting change	–
KALAMA 1 4KV	KAINALU	Voltage	2021	Dynamic LTC, Install two 1ph line regulators	$294,000
WAIALUA 3	KAWAILOA	Voltage	2021	LTC setting change	–
KAHALA 2 4KV	KILAUEA 4KV	Voltage	2023	Circuit phase balancing and Install 3ph line regulator	$213,600
MAKAKILO 2	MAKAKILO 2	Voltage	2023	LTC setting change	–
PIIKOI 3	MANOA-PIIKOI	Voltage	2023	Circuit phase balancing and LTC setting change	$3,600
MAKAHA 2	MAUKA	Voltage	2023	Circuit phase balancing	$3,600
KALAMA 1 4KV	ONEAWA	Voltage	2024	LTC setting change	–
PIIKOI 4	PIIKOI 8	Conductor overloading	2023	Reconductoring	$270,000
WAIALUA 3	WAIALUA	Voltage	2021	LTC setting change	–

Hawaiʻi Island

Table 4-10: Hawaii Island Grid Needs Assessment Using the Base DER Forecast

Substation	Circuit	Violation Type	Operating Date	Traditional Solution	Cost Estimate
Halaula	Halaula 1	Voltage	2024	Install two 3ph line regulator	$420,000
Hawaiian Paradise Park 2	Hawaiian Paradise Park 13	Voltage	2021	LTC setting change	-
Hawaiian Paradise Park 2	Hawaiian Paradise Park 14	Voltage	2021	LTC setting change	-
Honokaa 2	Honokaa 12	Voltage	2022	LTC setting change	-
Kapua 1	Kapua 11	Voltage	2021	LTC setting change	-
Kauhale	Kauhale 11	Voltage	2021	LTC setting change	-
Kauhale	Kauhale 12	Voltage	2021	LTC setting change	-
Keahole Airport	Keahole Airport 11	Voltage	2024	LTC setting change	-
Komohana 1	Komohana 12	Voltage	2021	LTC setting change	-
Kurtistown	Kurtistown 12	Voltage	2021	LTC setting change	-
Laupahoehoe	Laupahoehoe 2	Voltage	2022	LTC setting change	-
Namakani Paio	Namakani Paio	Voltage	2021	LTC setting change	-
Ookala	Ookala	Voltage	2021	LTC setting change	-
Orchid Isle	Orchid Isle 11	Voltage	2021	LTC setting change	-
Orchid Isle	Orchid Isle 12	Voltage	2021	LTC setting change	-
Paauilo	Paauilo 1	Voltage	2021	LTC setting change	-
Panaewa	Panaewa 12	Voltage	2021	LTC setting change	-
Puueo 2	Puueo 11	Voltage	2021	LTC setting change	-
Puueo 2	Puueo 12	Voltage	2021	LTC setting change	-
Puuwaawaa	Puuwaawaa 11	Voltage	2021	Install 3ph line regulator	$210,000
Waikoloa	Waikoloa 12	Voltage	2022	LTC setting change	-

Maui Island

Table 4-11: Maui Island Grid Needs Assessment Using the Base DER Forecast

Substation	Circuit	Violation Type	Operating Date	Traditional Solution	Cost Estimate
Kahului 5	Kahului 8/4049	Voltage	2021	LTC setting change	-
Kihei 4	Kihei 35/1515	Voltage	2025	LTC setting change	-
Kuau	Kuau 73/4066	Voltage	2021	LTC setting change	-
Kuihelani	Kuihelani 209/1653	Voltage	2021	LTC setting change	-
Kuihelani	Kuihelani 209/1708	Voltage	2021	LTC setting change	-
Kula	Kula 13/1237	Voltage, conductor overloading	2022	Reconductor and Install two 3ph line regulators	$2,235,909
Kula	Kula 13/1238	Voltage	2025	LTC setting change	-
Lahaina 5	Lahaina 34/1398	Voltage	2021	Install 3ph line regulator	$210,000
Paia Mauka	Paia Mauka 93/4042	Voltage	2021	Circuit phase balancing	$3,600
Peahi	Peahi 94/1294	Voltage	2021	LTC setting change	-
Pukalani 1	Pukalani 17/1282	Voltage	2022	LTC setting change	-
Spreckelsville	Spreckelsville 92/4043	Voltage	2021	LTC setting change	-
Waiinu 3	Waiinu 36/1493	Voltage	2022	LTC setting change	-
Wailea 4	Wailea 25/1517	Voltage	2023	LTC setting change	-
Wailea 4	Wailea 25/1518	Voltage	2023	LTC setting change	-

Lana'i

Table 4-12: Lanai Grid Needs Assessment Using the Base DER Forecast

Substation	Circuit	Violation Type	Operating Date	Traditional Solution	Cost Estimate
Miki Basin	Miki Basin PP 302/1208	Voltage	2023	Install 3ph line regulator	$252,000
Miki Basin	Miki Basin PP 302/1210	Voltage	2023	Install 3ph line regulator	$252,000

Moloka'i

Table 4-13: Molokai Grid Needs Assessment Using the Base DER Forecast

Substation	Circuit	Violation Type	Operating Date	Traditional Solution	Cost Estimate
Palaau	Palaau PP 81/109B	Voltage	2023	Install 3ph line regulator	$252,000
Palaau	Palaau PP 81/110B	Voltage	2021	Install 3ph line regulator	$252,000
Palaau	Palaau PP 81/111A	Voltage	2021	Install three 3ph line regulator	$756,000

4.3 LOW DER FORECAST

Using the low DER forecast, of the 50 circuits identified as requiring grid needs in Section 3.5.3, 35 circuits have solution options that can be addressed through minimal infrastructure investments (e.g. LTC settings change) and 15 circuits require infrastructure investments.

Table 4-14: Grid Needs Assessment Summary Using the Low DER Forecast

Island	Total Circuits[40]	Violation Type[41]		Solution Option	
		Voltage	Conductor Overload	Non-Infrastructure Investments[42]	Infrastructure Investments
O‘ahu	10	9	1	5	5
Hawai‘i Island	21	21	–	19	2
Maui Island	14	14	1	11	3
Lana‘i	2	2	–	–	2
Moloka‘i	3	3	–	–	3
Total (All Islands)	50	49	2	35	15

The grid needs assessment by island by circuit are detailed in the following tables.

O‘ahu

Table 4-15: O‘ahu Grid Needs Assessment Using the Low DER Forecast

Substation	Circuit	Violation Type	Operating Date	Traditional Solution	Cost Estimate
WAILUPE	AINA KOA	Voltage	2024	Circuit phase balancing	$7,200
KALAMA 1 4KV	KAINALU	Voltage	2021	Dynamic LTC	$154,000
AIKAHI 1	KALAHEO	Voltage	2023	LTC setting change	–
WAIALUA 3	KAWAILOA	Voltage	2021	LTC setting change	–

40 "Total Circuits" represents the number of circuits that have grid needs requirements.

41 Circuit totals by violation type do not match the total circuits column as some circuits have both voltage and conductor overload violations and are counted in both columns.

42 LTC settings changes only.

Substation	Circuit	Violation Type	Operating Date	Traditional Solution	Cost Estimate
KAHALA 2 4KV	KILAUEA 4KV	Voltage	2024	Circuit phase balancing and Install 3ph line regulator	$213,600
MAKAKILO 2	MAKAKILO 2	Voltage	2023	LTC setting change	-
MAKAHA 2	MAUKA	Voltage	2023	Circuit phase balancing	$3,600
KALAMA 1 4KV	ONEAWA	Voltage	2024	LTC setting change	-
PIIKOI 4	PIIKOI 8	Conductor overloading	2025	Reconductoring	$270,000
WAIALUA 3	WAIALUA	Voltage	2022	LTC setting change	-

Hawaiʻi Island

Table 4-16: Hawaii Island Grid Needs Assessment Using the Low DER Forecast

Substation	Circuit	Violation Type	Operating Date	Traditional Solution	Cost Estimate
Halaula	Halaula 1	Voltage	2024	Install two 3ph line regulator	$420,000
Hawaiian Paradise Park 2	Hawaiian Paradise Park 13	Voltage	2021	LTC setting change	-
Hawaiian Paradise Park 2	Hawaiian Paradise Park 14	Voltage	2021	LTC setting change	-
Honokaa 2	Honokaa 12	Voltage	2022	LTC setting change	-
Kapua 1	Kapua 11	Voltage	2021	LTC setting change	-
Kauhale	Kauhale 11	Voltage	2021	LTC setting change	-
Kauhale	Kauhale 12	Voltage	2021	LTC setting change	-
Keahole Airport	Keahole Airport 11	Voltage	2024	LTC setting change	-
Komohana 1	Komohana 12	Voltage	2021	LTC setting change	-
Kurtistown	Kurtistown 12	Voltage	2021	LTC setting change	-

Substation	Circuit	Violation Type	Operating Date	Traditional Solution	Cost Estimate
Laupahoehoe	Laupahoehoe 2	Voltage	2022	LTC setting change	-
Namakani Paio	Namakani Paio	Voltage	2021	LTC setting change	-
Ookala	Ookala	Voltage	2021	LTC setting change	-
Orchid Isle	Orchid Isle 11	Voltage	2021	LTC setting change	-
Orchid Isle	Orchid Isle 12	Voltage	2021	LTC setting change	-
Paauilo	Paauilo 1	Voltage	2021	LTC setting change	-
Panaewa	Panaewa 12	Voltage	2021	LTC setting change	-
Puueo 2	Puueo 11	Voltage	2021	LTC setting change	-
Puueo 2	Puueo 12	Voltage	2021	LTC setting change	-
Puuwaawaa	Puuwaawaa 11	Voltage	2021	Install 3ph line regulator	$210,000
Waikoloa	Waikoloa 12	Voltage	2022	LTC setting change	-

Maui Island

Table 4-17: Maui Island Grid Needs Assessment Using the Low DER Forecast

Substation	Circuit	Violation Type	Operating Date	Traditional Solution	Cost Estimate
Kahului 5	Kahului 8/4049	Voltage	2021	LTC setting change	-
Kuau	Kuau 73/4066	Voltage	2021	LTC setting change	-
Kuihelani	Kuihelani 209/1653	Voltage	2021	LTC setting change	-
Kuihelani	Kuihelani 209/1708	Voltage	2021	LTC setting change	-
Kula	Kula 13/1237	Voltage, conductor overloading	2022	Reconductor and Install two 3ph line regulators	$2,235,909
Kula	Kula 13/1238	Voltage	2025	LTC setting change	-

Substation	Circuit	Violation Type	Operating Date	Traditional Solution	Cost Estimate
Lahaina 5	Lahaina 34/1398	Voltage	2021	Install 3ph line regulator	$210,000
Paia Mauka	Paia Mauka 93/4042	Voltage	2021	Circuit phase balancing	$3,600
Peahi	Peahi 94/1294	Voltage	2021	LTC setting change	-
Pukalani 1	Pukalani 17/1282	Voltage	2022	LTC setting change	-
Spreckelsville	Spreckelsville 92/4043	Voltage	2021	LTC setting change	-
Waiinu 3	Waiinu 36/1493	Voltage	2023	LTC setting change	-
Wailea 4	Wailea 25/1517	Voltage	2023	LTC setting change	-
Wailea 4	Wailea 25/1518	Voltage	2023	LTC setting change	-

Lana'i

Table 4-18: Lanai Grid Needs Assessment Using the Low DER Forecast

Substation	Circuit	Violation Type	Operating Date	Traditional Solution	Cost Estimate
Miki Basin	Miki Basin PP 302/1208	Voltage	2023	Install 3ph line regulator	$252,000
Miki Basin	Miki Basin PP 302/1210	Voltage	2022	Install 3ph line regulator	$252,000

Moloka'i

Table 4-19: Molokai Grid Needs Assessment Using the Low DER Forecast

Substation	Circuit	Violation Type	Operating Date	Traditional Solution	Cost Estimate
Palaau	Palaau PP 81/109B	Voltage	2023	Install 3ph line regulator	$252,000
Palaau	Palaau PP 81/110B	Voltage	2021	Install 3ph line regulator	$252,000
Palaau	Palaau PP 81/111A	Voltage	2021	Install three 3ph line regulator	$756,000

5 Summary and Next Steps

With the use of advanced tools and analysis (e.g., LoadSEER and Synergi), the Company has been able to do a wide-scale update of the available hosting capacity on all primary distribution circuits, as well as determine which circuits require further analysis to accommodate the total anticipated DER in year 2025.

Using the high DER forecast, the analysis finds:

- 527 circuits do not require grid needs:
  - 435 circuits can accommodate the 5-year DER forecast with existing hosting capacity.
  - 92 circuits can accommodate the 5-year DER forecast through updated hosting capacity without modifications.
- 93 circuits require grid needs at the primary distribution circuit-level:
  - 60 circuits can accommodate through minimal investment (e.g., LTC setting changes).
  - 33 circuits require solutions/mitigations, which will serve as an input to the Grid Needs Assessment stage of the IGP process. Total estimated costs for traditional solutions on all islands is $10.7 M.

Updated hosting capacities and implementation of the above mitigations and solutions will provide an increase of hosting capacity of 64 MW on O‘ahu, 37 MW on Hawai‘i Island, 64 MW on Maui Island, 0.17 MW on Lana‘i, and 1.4 MW on Moloka‘i.[43]

Using the base DER forecast, the analysis finds:

- 567 circuits do not require grid needs:
  - 509 circuits can accommodate the 5-year DER forecast with existing hosting capacity.
  - 58 circuits can accommodate the 5-year DER forecast through updated hosting capacity without modifications.
- 53 circuits require grid needs at the primary distribution circuit-level:
  - 37 circuits can accommodate through minimal investment (e.g., LTC setting changes).

[43] Hosting capacity increases quantified are circuit-level hosting capacity only and not representative of the system-level hosting capacity which may be lower due to system-level constraints that are not evaluated during this process.

- 16 circuits require solutions/mitigations, which will serve as an input to the Grid Needs Assessment stage of the IGP process. Total estimated costs for traditional solutions on all islands is $5.6 M.

Updated hosting capacities and implementation of the above mitigations and solutions will provide an increase of hosting capacity of 27 MW on O'ahu, 20 MW on Hawai'i Island, 47 MW on Maui Island, 0.04 MW on Lana'i, and 0.5 MW on Moloka'i.[43]

Using the low DER forecast, the analysis finds:

- 570 circuits do not require grid needs:
  - 517 circuits can accommodate the 5-year DER forecast with existing hosting capacity.
  - 53 circuits can accommodate the 5-year DER forecast through updated hosting capacity without modifications.
- 50 circuits require grid needs at the primary distribution circuit-level:
  - 35 circuits can accommodate through minimal investment (e.g., LTC setting changes).
  - 15 circuits require solutions/mitigations, which will serve as an input to the Grid Needs Assessment stage of the IGP process. Total estimated costs for traditional solutions on all islands is $5.5 M.

Updated hosting capacities and implementation of the above mitigations and solutions will provide an increase of hosting capacity of 22 MW on O'ahu, 20 MW on Hawai'i Island, 45 MW on Maui Island, 0.04 MW on Lana'i, and 0.5 MW on Moloka'i.[43]

Consistent with the *Non-Wires Opportunity Evaluation Methodology*,[44,45] cost estimates are developed for solutions that require significant upgrades. These estimates will be used as inputs to the Grid Needs Assessment stage of the IGP process to evaluate if they qualify as an NWA opportunity, and if so, be procured as part of the overarching IGP process where a portfolio of solutions will be selected to address the identified grid needs.

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[44] Hawaiian Electric, Non-Wires Opportunity Evaluation Methodology June 2020, https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/distribution_planning/20200602_dpwg_non_wires_opportunity_evaluation_methodology.pdf

[45] Concurrent to this filing, an update to the Non-Wires Opportunity Evaluation Methodology was filed in the Grid Needs Assessment (Nov. 2021, Dkt. No. 2018-0165). References in this document are made to the document in footnote 52.

Appendix A: Workbook Index

The DER forecasts, hosting capacity analysis, and grid needs for each scenario by island are available on the Company's website in Excel workbooks as the tables are too voluminous to provide in table format herein.[46]

A summary of the workbooks is provided below.

Table A-1: Distribution DER Hosting Capacity Grid Needs Workbook Index

Scenario	Modeling Case	DER Forecast	Workbook[47]
1	Base	Base Forecast	Distribution DER Hosting Capacity Grid Needs Base Forecast (EXCEL) (November 2021)
2	High Load Customer Technology Adoption Bookend	Low Forecast	Distribution DER Hosting Capacity Grid Needs Low Forecast (EXCEL) (November 2021)
3	Low Load Customer Technology Adoption Bookend	High Forecast	Distribution DER Hosting Capacity Grid Needs High Forecast (EXCEL) (November 2021)

[46] *See* https://www.hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning/stakeholder-engagement/key-stakeholder-documents

[47] File name as it appears on the Company website.

Appendix B: Stakeholder Engagement

The Company recognizes stakeholder engagement as an integral part of the IGP process. In an effort to proactively solicit stakeholder feedback on this report, the Company provided a preliminary report, the October 2021 Update, to stakeholders for review and comment on October 1, 2021. The Company subsequently met with the STWG on October 6, 2021 to address questions and receive feedback from the stakeholders. Meeting minutes capturing feedback from the discussion and presentation materials from the meeting can be found on the IGP website.[48]

Additionally, the Company received feedback from various Organizations which is consolidated anonymously below. Feedback from stakeholders in this section are shown in **bold**, and the Company's response to the questions or feedback are shown in *italics*.

1. **Does Hawaiian Electric plan to run the Hosting Capacity analysis with variations of forecast layers other than DERs (i.e. EoT adoption, EE, etc.)?**

   Hawaiian Electric does not plan to run the HC analysis with variations of forecast layers other than DERs. Different variations of forecast layers for EoT and EE were included with the Locational Forecast report.

2. **At 9, Hawaiian Electric states, "This document focuses on hosting capacity grid needs identified for the next five years (year 2021 through 2025) driven by the forecast DER growth on distribution circuits…" How often will Hawaiian Electric update this distribution hosting capacity?**
   a. **Will updates occur every five years to align with the timeline analyzed in this analysis, or will updates occur along with the shorter IGP cycle?**

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

Distribution circuit hosting capacity numbers are updated in the Locational Value Map ("LVM")[49] as technical reviews for DER applications are performed. Hosting capacity grid needs will be updated with each IGP cycle.

b. **In light of the RESOLVE and PLEXOS modeling using 2025 as a start year, how will mid-term distribution grid-needs (2025-2030) and long-term distribution grid needs (beyond 2030) be integrated into the IGP process?**

Identifying distribution grid needs beyond five years is highly uncertain as developers do not have concrete plans more than 3-5 years in advance. Therefore, the Company would not identify needs that lead to distribution grid investments more than 5 years before it is expected to be needed.

3. **At 15, HECO states, "This 30MW of CBRE Phase 2 small projects were included by adding 6 MW per year to the corporate DER forecast. This was done for each scenario: Base, Low, and High. This amount is divided into residential and commercial customer types and is used as the system level DER limit for the spatial allocation in LoadSEER." Please clarify whether the 30 MW of CBRE is the total system level DER limit for the spatial allocation in LoadSEER, or whether this is added to the corporate forecast. Additionally, please clarify why splitting commercial and residential unnecessary for this HCA.**

The 30 MW of CBRE is added in addition to the corporate DER forecast. For the hosting capacity analysis, the amount of commercial and residential DERs that were allocated on each circuit were added together to determine the total forecasted DER on the circuit. Splitting the commercial and residential PV is unnecessary because the impact to hosting capacity is the same.

[49] LVMs for each island are available on the Company website at: https://www.hawaiianelectric.com/clean-energy-hawaii/integration-tools-and-resources/locational-value-maps.

4. **It would be helpful to clarify (or re-describe) what "total circuits" represents in Table 4.**

   In Table 4,[50] the "Total Circuits" represents the number of circuits that have grid needs requirements for the high DER forecast scenario.[51]

5. **For Tables 5-9 (at 28-34), how did Hawaiian Electric develop cost estimates for solutions to expand hosting capacity requiring infrastructure investments?**

   The cost estimates in Tables 5-9[52] are high-level estimates using unit costs based on previous similar projects.[53]

6. **At 21, it is explained that "the hosting capacity is determined for a snapshot in time, specifically the hour representing the daytime minimum load ("DML")". Out of what time-series data are the daytime minimum load and peak demand hours selected (i.e. from 8760 hours for a given year, for multiple years, from a representative day in each month, etc.)?**

   Generally, the previous year's 8760 data (i.e., year 2020) was used to select daytime minimum or peak demand load hours. In cases where there may be missing data, an earlier year's data is used.

   a. **Did HECO consider looking at time periods other than the DML to perform the analysis?**

      Currently and in the near future, the DML time period represents the circuits' hosting capacity limit due to the high amounts of PV. As BESS penetration increases, other time periods will be analyzed.

[50] Table 4 in the October 2021 Update is relabeled as Table 4-2 in this report.
[51] See Section 4.1 High DER Forecast at 31.
[52] Tables 5 through 9 in the October 2021 Update are relabeled as Table 4-3 through Table 4-7 in this report.
[53] See Section 4 Grid Needs at 27.

b. **If so, what were the alternatives considered and what lead HECO to choosing to perform the analysis based on the DML?**

See response to 6.a.

7. **At 16, HECO explains that the forecasted DER growth is based on executed DER in selected programs and adjustments are made for large projects (including CBRE Phase 1, FIT, and large SIA) and for CBRE Phase 2 small projects. At 13, HECO states that battery energy storage capacity is not included in the aggregated DER values. Please confirm that the DER growth analyzes PV technology only.**

The DER growth for the hosting capacity analysis looked at PV technology only. Energy storage profiles were removed from the executed DER amount as they are not expected to export coincidentally with DGPV. The analysis focused on hosting capacity during the day. However, the intent is to move toward a more time-based analysis to account for battery systems discharging at other times of the day as battery system penetration increases.

a. **If so, how was the load profile determined for the PV additions (i.e. a composite of historic profiles weighted across the different programs, one uniform PV profile, etc.)?**

Historical load measurements that include executed DERs were used to determine the load. Future PV additions up to the circuit hosting capacity were modeled at 100% rated capacity.

b. **If not, which different types of DERs make up the expected DER growth and how was the load profile determined for this mix of DERs?**

For this filing we considered DGPV growth and didn't account for the other layers in the hosting capacity analyses.

c. **If the DER growth forecast only analyzes PV technology, how will HECO account for the prevalence of paired solar plus storage systems plus other**

DERs such as EVs, EE, and DR equipment and their effect on circuit hosting capacity?

The locational forecast includes the Energy storage, EV, and EE layers. In the future these layers will be accounted through LoadSEER and the output files will be considered for analysis.

EXHIBIT 5

AEG IGP Supply Curve Memo

Applied Energy Group

MEMORANDUM

To: Christopher Lau, HECO Team

From: Eli Morris, Ken Walter and Fuong Nguyen, Applied Energy Group (AEG)

Date: November 1, 2021

RE: HECO IGP Supply Curve Inputs

In 2021, Hawaiian Electric Company (HECO) engaged AEG to develop energy efficiency supply curves for inclusion in its 2021 Integrated Grid Plan (IGP) using the results of the Hawaii statewide potential study AEG performed on behalf of the Hawaii Public Utility Commission. The supply curves are designed to allow Hawaiian Electric to consider energy efficiency as a resource on par with supply-side options. In addition to supply curve development, AEG assisted HECO with stakeholder engagement to gather input and buy-in on the methodology and key components of the supply curve development effort.

This memo describes the key aspects of the supply curve development support AEG provided to HECO, including stakeholder engagement, measure bundling methodology, and summary supply curve information.

Stakeholder Engagement

AEG worked with HECO to present information, solicit feedback and respond to questions from stakeholders throughout this the supply curve development process. A summary of stakeholder engagement activities is provided below:

- On September 7th, AEG presented the general supply curve methodology and bundling process to stakeholders during the HECO's IGP stakeholder meeting.
- On September 15th, AEG responded to questions from the Consumer Advocate regarding the Hawaii Statewide Market Potential Study (MPS) used as the basis for the supply curves, clarifying the development of the MPS business-as-usual potential case, achievable high case, and codes and standards in the model.[1] AEG's responses were incorporated into HECO's Reply to Party Comments and Commission Questions that was filed on September 21, 2021, in Docket No. 2018-0165.
    - Following this meeting, draft supply curves were uploaded to the IGP website for stakeholder review and comment.
- On September 23rd, AEG attended the Technical Working Group meeting to provide additional clarity and context regarding the supply curve bundling and definition of incremental potential as it would be applied in the IGP model.
    - AEG provided updated draft supply curves revising the incremental potential to eliminate re-purchases (described later in this document) and including exhibits responsive to stakeholder feedback.
- On October 18th, AEG provided responses to additional Information Requests (IRs) from Commission staff clarifying the definitions of potential used for the supply curves and their relationship to the potential

[1] Division of Consumer Advocacy's Comments on the August IGP Update filed on September 10, 2021, in Docket No. 2018-0165 at 6.

levels in the Statewide MPS, as well as definitions for the peak period under consideration.[2] AEG noted at this time that the supply curve summary files would be updated to include peak MW impacts and costs in $/MW in addition to the energy-focused (MWh) summary information previously included.

- Draft supply curves including MW impacts and $/MW were provided to HECO on October 29th, to be uploaded for stakeholder review and comment. Upon review by HECO, the hourly impacts were unitized to be used in conjunction with the cumulative peak impact by bundle and $/MW costs adjusted for cumulative measure impacts to better align with the available modeling input fields in its RESOLVE model.

Documents pertaining to stakeholder engagement and responses can be found here: https://www.hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning/stakeholder-engagement/key-stakeholder-documents

Energy Efficiency Supply Curve Development Methodology

There are two primary options for incorporating energy efficiency resources into integrated grid planning:

1. Use one of the achievable potential cases form the Statewide Market Potential Study, which has already been screened for cost-effectiveness. The expected amount of cost-effective and achievable potential would be decremented from the load forecast.
2. Perform the economic screening in the IGP, treating energy efficiency as an available resource that can be selected based on its cost and value. This option requires creating a new level of energy efficiency potential, referred to as "achievable technical," which has not been screened for cost-effectiveness.

The advantage of using option 1 is that it is simple to implement in the IGP as a decrement to the load forecast. However, the disadvantage of this option is that it requires a determination of avoided costs prior to running the IGP. Because of this, energy efficiency resource bundles are either in or out in every scenario, so the IGP model is not able to assess how the optimal level of energy efficiency may vary based on changes in other assumptions.

Option 2 allows the IGP to dynamically select cost-effective resources based on more granular cost groupings and competing resources. It also allows different IGP scenarios to select different bundles according to the needs under each scenario. The downside of using this option is that each bundle that competes in the IGP increases the run time of the model, so thought must be given to the optimal number of resource bundles, considering tradeoffs in data granularity and model performance.

Based on HECO's IGP objectives and considering stakeholder input, it was determined that Option 2 was the most appropriate way to consider energy efficiency within the IGP. The remainder of this methodology section describes the process AEG employed to develop supply curves that enable dynamic resource optimization within the IGP while accounting for limitations in the number of resources that could be modeled.

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 for IGP modeling, AEG applied the customer participation rates from the "Future Achievable – High" case form the Statewide MPS, which account for market barriers, customer awareness and attitudes, program maturity, and other factors that may affect market penetration of energy efficiency measures.

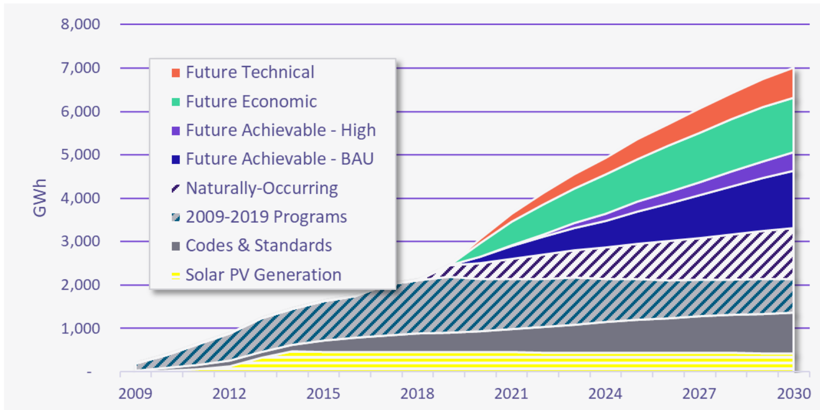
Differences from the Hawaii statewide potential study

Figure 1 (also included in the Statewide MPS report) illustrates the levels of potential assessed in the Statewide MPS. Striped layers show impacts that are contained in the baseline forecast and therefore not part of the

[2] HECO's Response to Commission's Information Requests filed on October 25, 2021, in Docket No. 2018-0165.

energy efficiency supply curves. These categories include naturally occurring efficiency, codes & standards impacts, and the lingering effects of past program achievement.

[3]



Because the achievable technical potential used to develop the IGP supply curves does not consider cost-effectiveness, it is not the same as any of the levels of potential shown in Figure 1. Rather, the amount of available achievable technical potential would fall between the "Future Technical" and "Future Achievable – High" potentials.

Measure Grouping

As discussed above, each resource modeled in the IGP model increases the required runtime. Therefore, it is important to design bundles around meaningful metrics to allow the IGP model to assess the relative cost and value of different levels of energy efficiency without having to consider a large number of distinct resources. Based on discussions with HECO regarding when energy efficiency provides the most value, AEG bundled the measures based on two factors: relative contributions during peak periods and cost-effectiveness (as determined in the Statewide MPS).

Peak Impacts

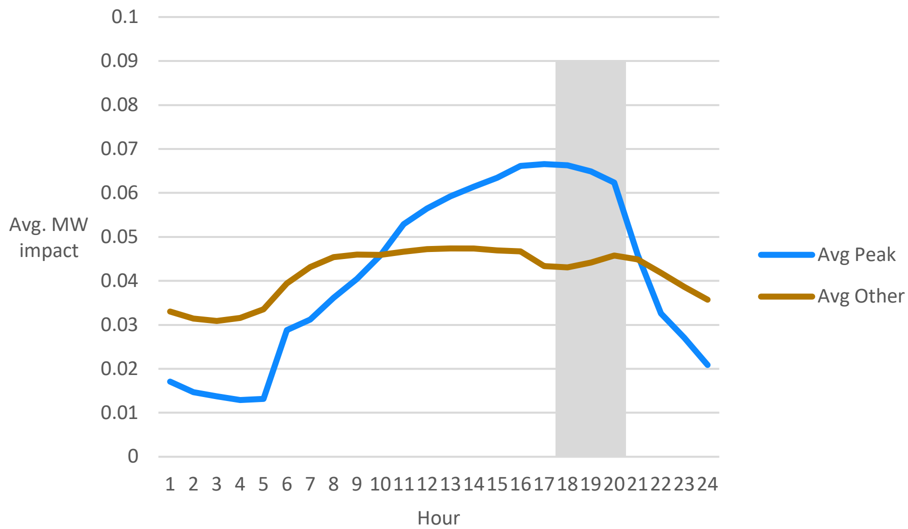
Each energy efficiency measure has an island-specific load shape, which was created during the potential study process. By taking the annual savings calculated from the potential study and distributing it across this shape, impacts in each hour of the year can be calculated for each measure shape.

For the first level of bundling, AEG considered the relative "peakiness" of each measure by comparing its impacts during HECO's peak hours to a flat shape. This calculation determined which measures would be considered peak-focused and which measures' impacts were mainly in non-peak hours. Where referenced in this document and related workbooks, 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 2 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.

[3] 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 2 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. Through conversation with HECO, it was decided that although 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. Because the benefit-cost ratios (using the Total Resource Cost test perspective) from the Statewide MPS capture both energy and capacity benefits, these ratios represent a convenient metric for bundling measures considering both cost and value. Table 1 shows the ranges used for bundle classification, which serve to separate measures that are highly cost effective (A) from those which were potentially more sensitive to IGP scenarios (B and C), and finally isolate very non-cost-effective measures (D) to avoid them skewing the overall cost of the more attractive groups.

Table 1 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 because peak-focused measures gain extra value in terms of cost-effectiveness, 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 IGP model's needs, it might choose lower absolute costs first, which could produce differences between the IGP model selections and the MPS. This flexibility is an expected feature of the chosen methodology.

Bundle Creation

Once all measures were assigned to appropriate bundles based on peakiness and cost-effectiveness, AEG developed supply curves for IGP modeling, described based on their cost, energy and demand impacts, and hourly shape. The process for developing each component is described below.

Bundle Costs

To compete energy efficiency resources against other resources in the IGP, 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. As noted above, it is possible for measure LCOEs to be negative, therefore it is possible that a bundle can have a net negative cost if savings within the bundle are dominated by one or more measures with negative LCOEs.

Bundle Energy and Demand Impacts

The energy impacts within each bundle are the sum of the various measures assigned to it. Measure bundling assignments are available in the IGP documentation linked above, and a summary of bundles by end use is provided in the analysis results section below.

The reported peak demand impact of each bundle is similarly the sum of the peak hour impacts of each measure. The potential of various measures that would apply to the same end use in the peak hour is already accounted for in the potential study itself, so no further adjustment is needed to account for overlap of measures.

Bundle Hourly Shapes

Each bundle's hourly shape emerges from summing the constituent measure impacts in each hour of the year. This aggregated hourly shape is what is provided to the IGP.

Analysis Results

Figure 3 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 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 to be consistent with the IGP model.

In conversation with stakeholders, AEG acknowledged that 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 Market Potential Study. The modeled potential without re-acquisitions is a conservative estimate, but in discussion with HECO and stakeholders we reached agreement that a conservative estimate was preferable to overstating possible potential for this resource planning process.

Figure 3 Incremental Annual Energy Savings Potential (Achievable Technical) by Measure Bundle (All Islands Combined)

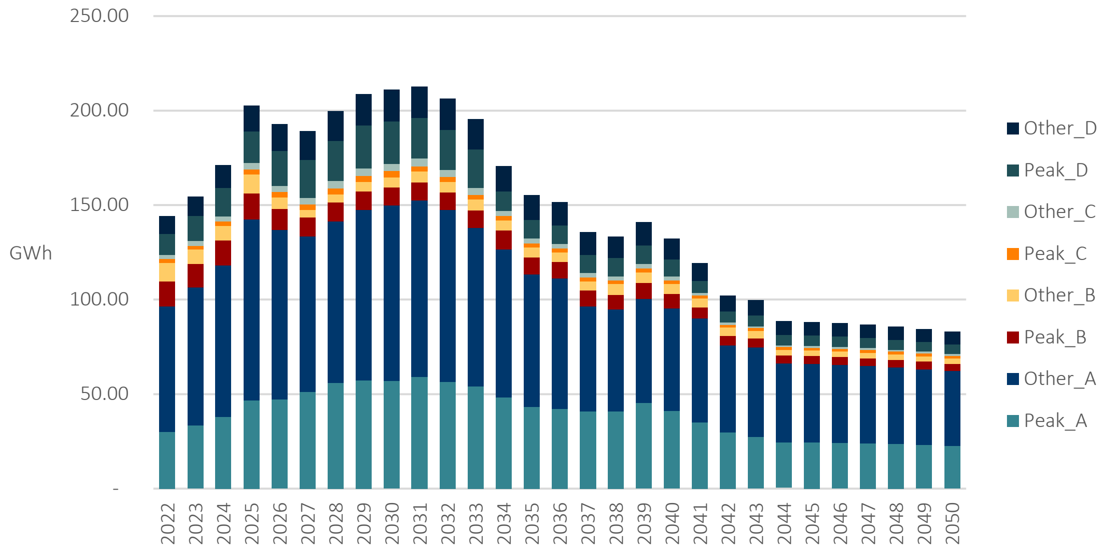


Table 2 and Figure 4 below show the cumulative energy savings by end use for each bundle. The savings here represent the total Achievable Technical Potential in 2045 from the MPS.[4]

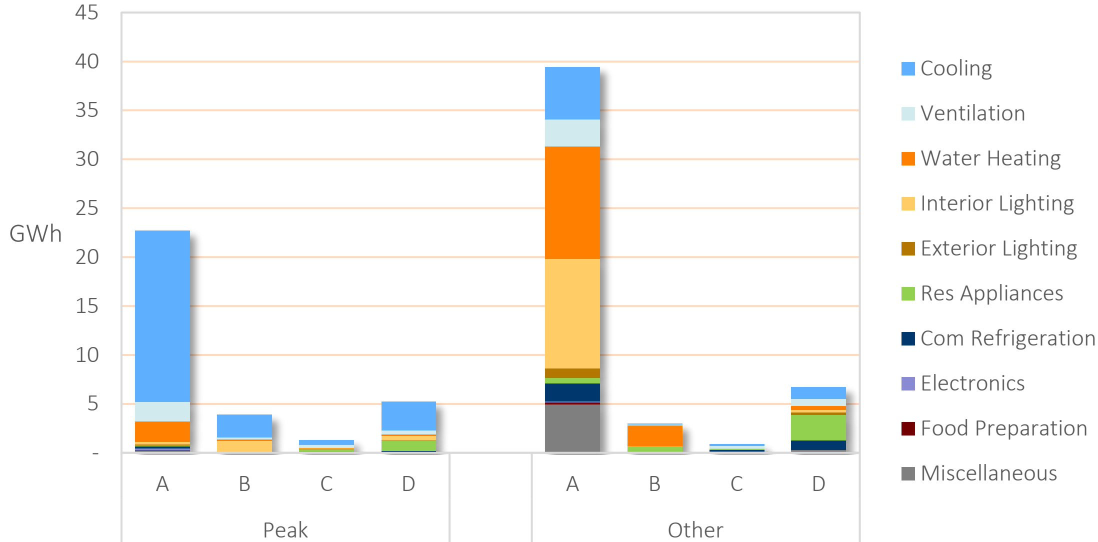
The Peak bundles are dominated by the cooling end use. The Peak A bundle, which includes the most cost-effective measures from the potential study, is gets 77% of its savings from the cooling end use. The Other bundles are made up mainly of water heating, lighting, and appliance measures, which tend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

Table 2 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**

[4] The Statewide MPS study period only ran to 2045. Annual potential from 2046-2050 shown in some charts and provided for the IGP was calculated based on the year-over-year trend from 2040-2045. This is consistent with HECO's methodology for the IGP.

Figure 4 Achievable Technical Energy Savings (GWh) by Measure Grouping and End Use (All Islands Combined)



With this categorization and bundling complete, the hourly impacts for each bundle across the planning horizon and associated levelized costs were provided to HECO for input into the IGP. 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).

Island Level Summary Results

Oahu Results

Figure 5 Oahu Annual Energy Savings Potential (Achievable Technical) by Measure Bundle

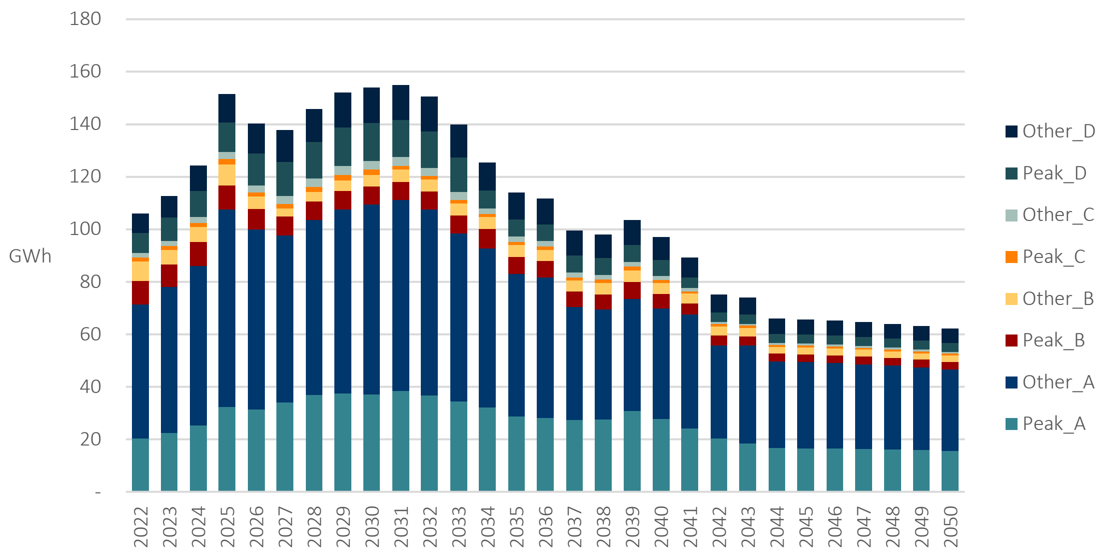
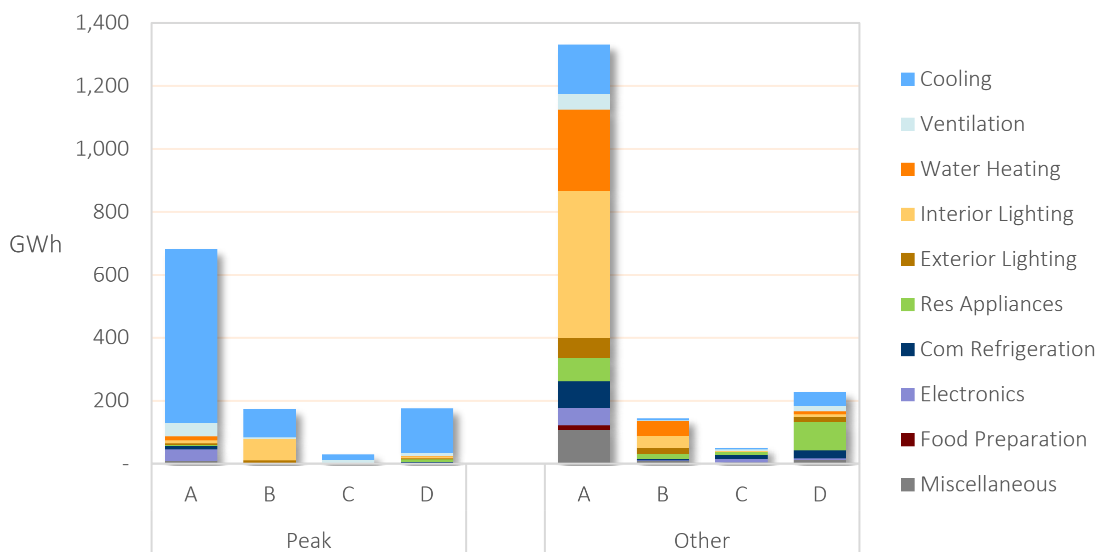


Figure 6 Oahu Achievable Technical Energy Savings (GWh) by Measure Grouping and End Use



Maui Results

Figure 7 *Maui Annual Energy Savings Potential (Achievable Technical) by Measure Bundle*

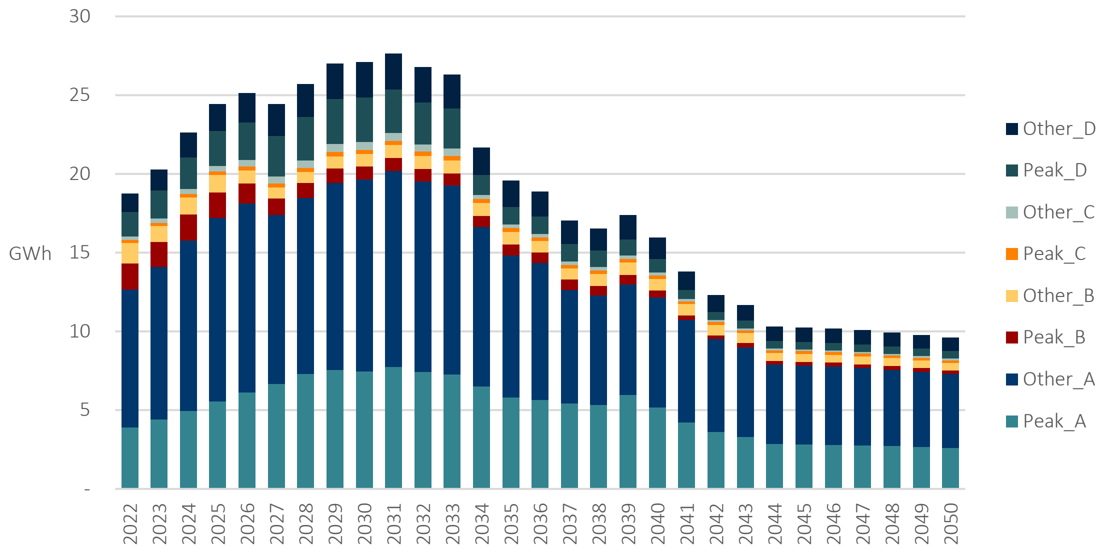
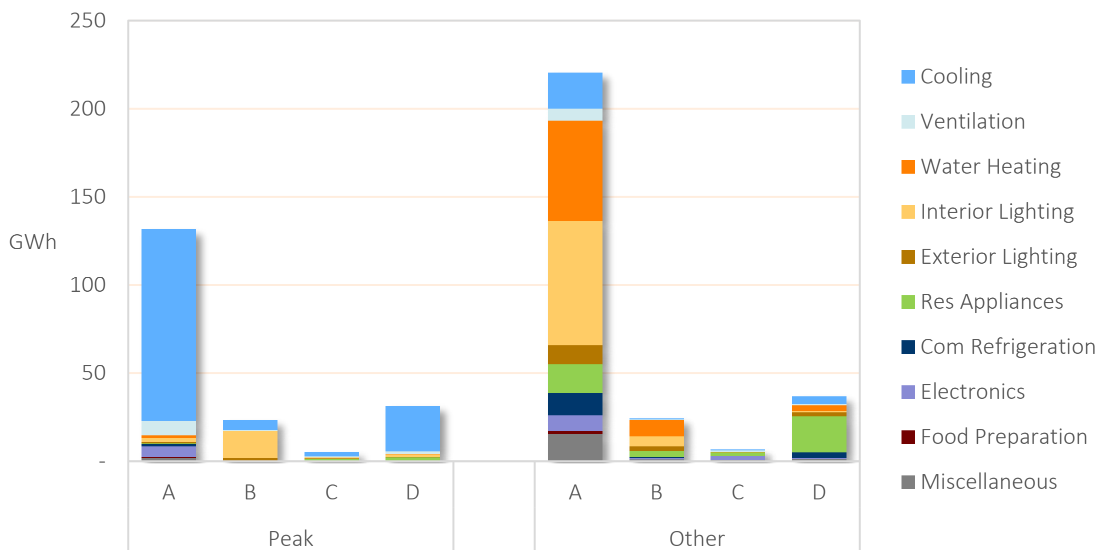


Figure 8 *Maui Achievable Technical Energy Savings (GWh) by Measure Grouping and End Use*



Hawaii Results

Figure 9 Hawaii Annual Energy Savings Potential (Achievable Technical) by Measure Bundle

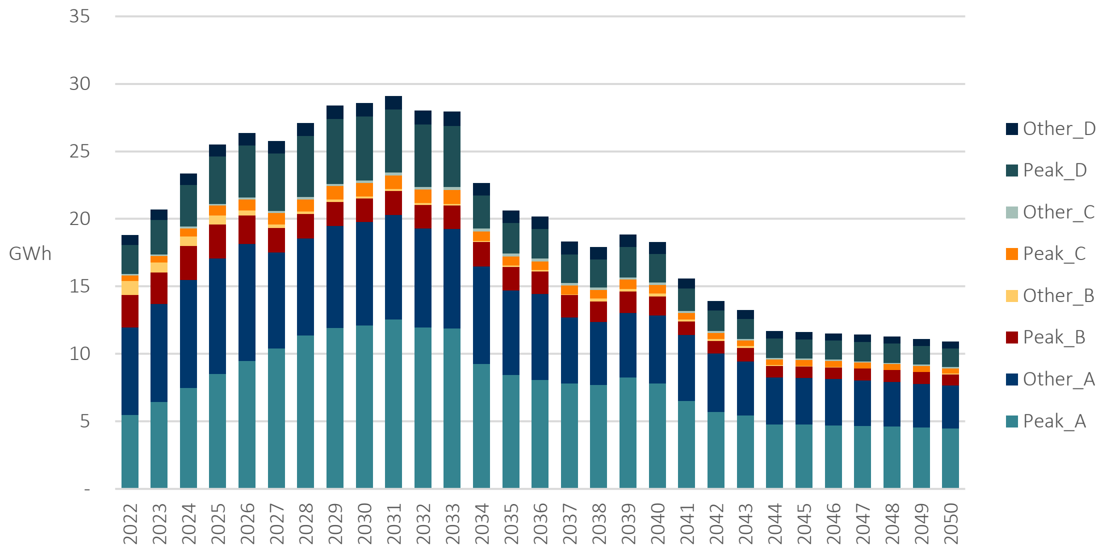
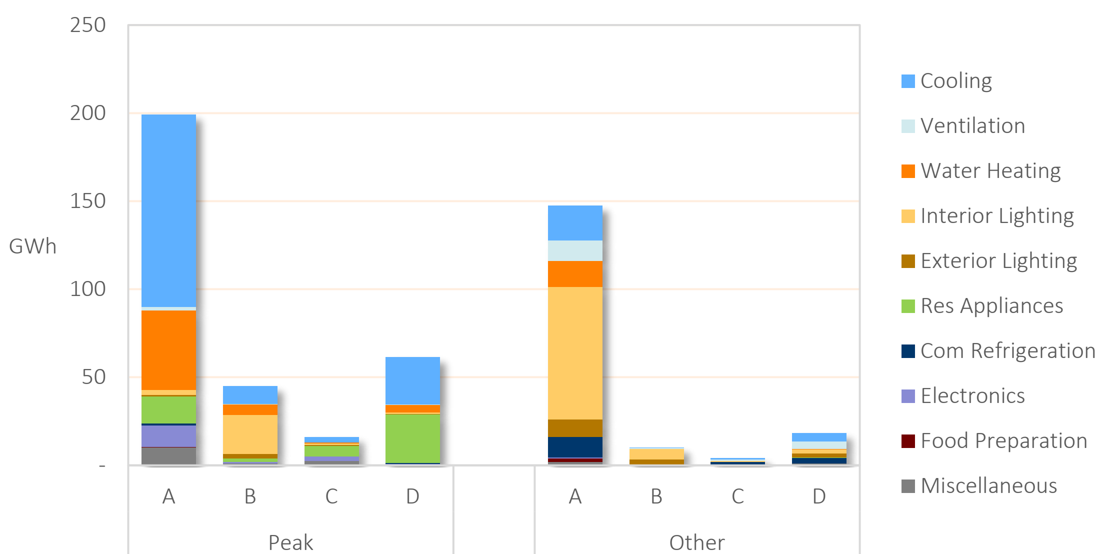


Figure 10 Hawaii Achievable Technical Energy Savings (GWh) by Measure Grouping and End Use



Lanai Results

Figure 11 Lanai Annual Energy Savings Potential (Achievable Technical) by Measure Bundle

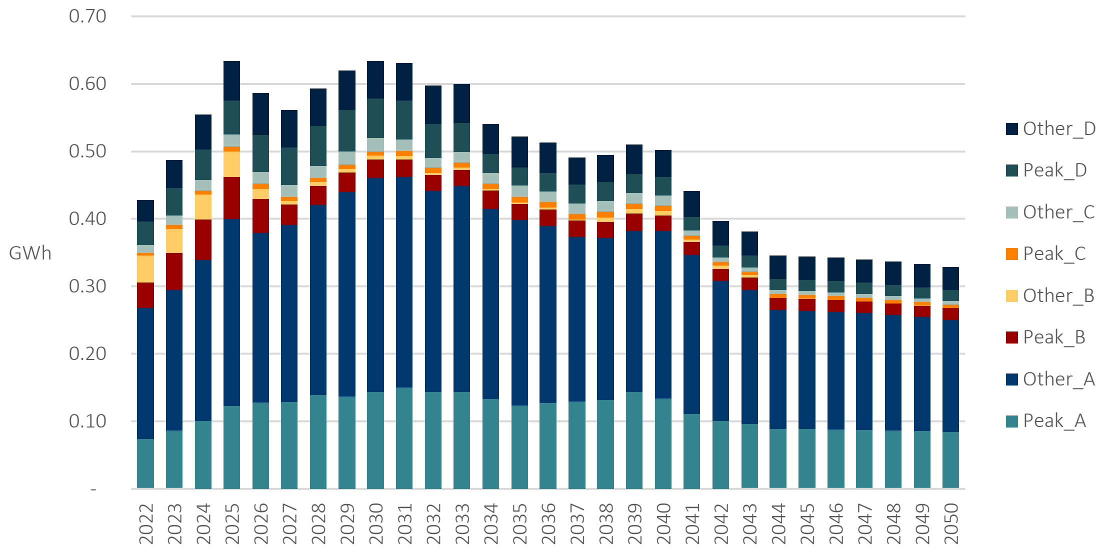
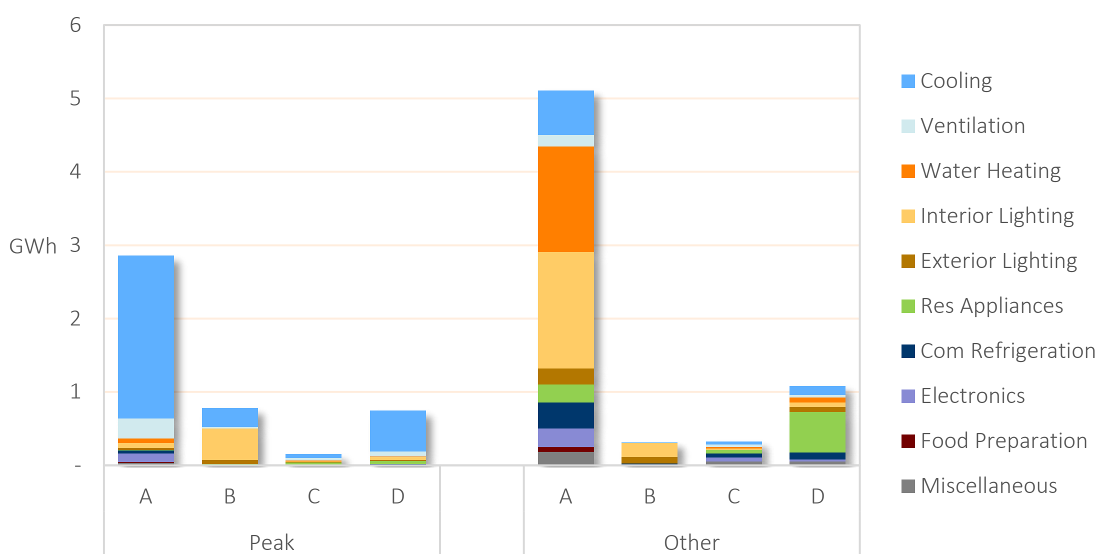


Figure 12 Lanai Achievable Technical Energy Savings (GWh) by Measure Grouping and End Use



Molokai Results

Figure 13 Molokai Annual Energy Savings Potential (Achievable Technical) by Measure Bundle

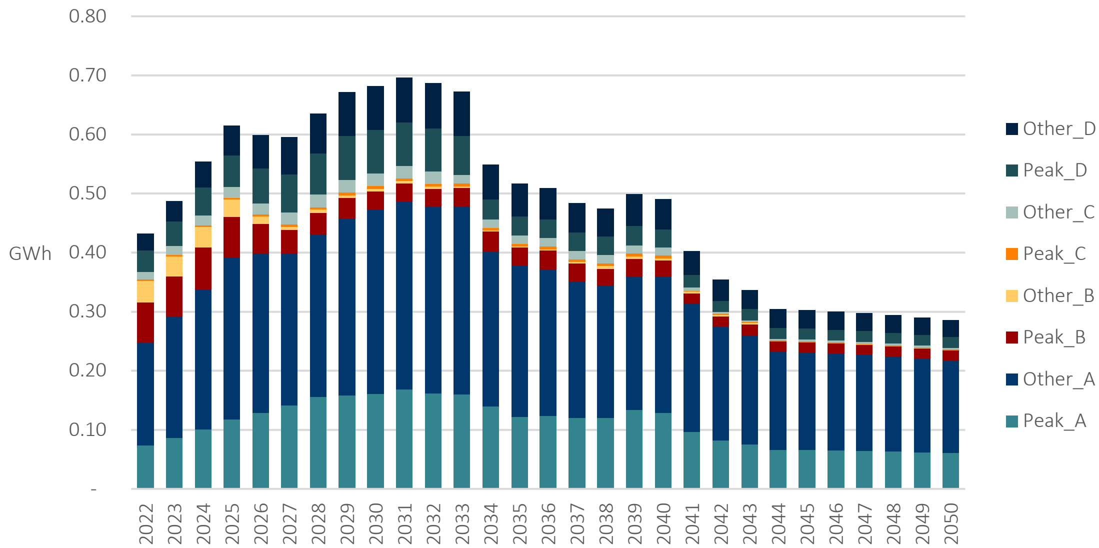


Figure 14 Molokai Achievable Technical Energy Savings (GWh) by Measure Grouping and End Use

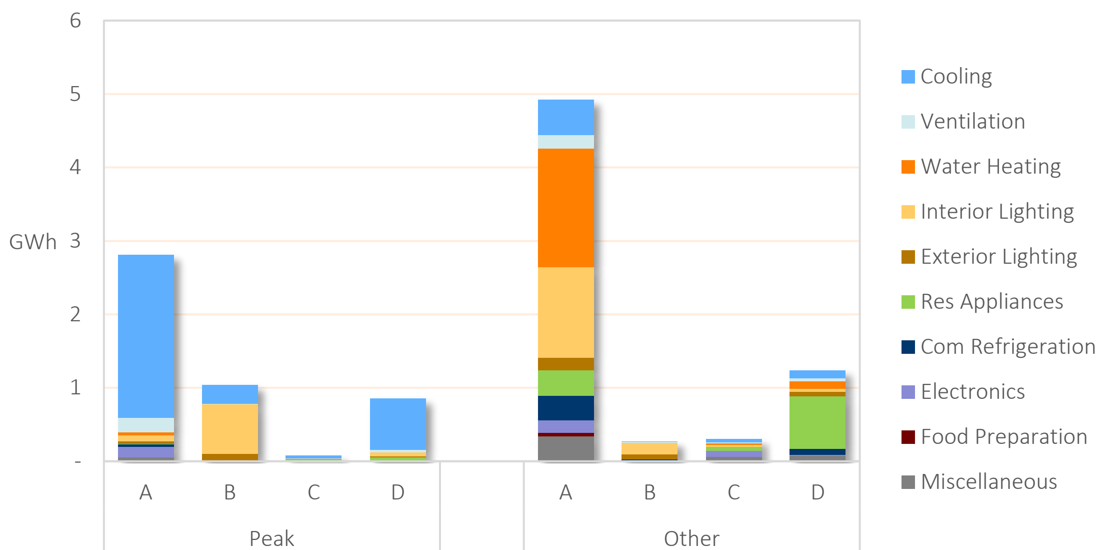


EXHIBIT 6

Redlined Updates to Inputs and Assumptions

Hawaiian Electric

2021 Integrated Grid Planning Inputs and Assumptions

Revised August 2021 Update

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4 Forecast Assumptions

The modeling process for the Grid Needs Assessment relies on a set of forecast assumptions to define what the future system could look like. Many of these assumptions have been developed by the Forecast Assumptions Working Group (FAWG), the Solution Evaluation & Optimization Working Group (SEOWG), and the STWG.

4.1 LOAD FORECAST

The load forecast is a key assumption for the planning models that provides the energy requirements and peak demands that must be served by Hawaiian Electric through the planning horizon. The forecasts will be used to start the planning process along with sensitivities discussed with the TAP, FAWG, SEOWG, and STWG. Because of the importance of the load forecast and peak demand in resource modeling, the TAP recommended the use of high and low bookends to test how the cost and portfolio of resources would change for a range of peak demand and load profiles. The load forecast is just one of the many assumptions that the resource planners use in their models to stress test the various plans under varying conditions. Scenario and sensitivities as described in Section 6 were developed to help address uncertainty in providing a range of forecasts to plan around given the uncertainties surrounding adoption of behind the meter technologies, which ultimately drive the load forecast and peak demand. Additional sensitivities may also be identified in the resource planning stage.

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

The underlying load forecast is driven primarily by the economy, weather, electricity price, and known adjustments to large customer loads and is informed by historical data, structural changes[25], 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

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

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.

Multiple methods and models were analyzed to develop the underlying forecast as presented in the July 17, 2019 FAWG meeting.[26] The forecasts and assumptions presented in the FAWG meetings held from March 2019 through March 2020 and described in the response to PUC-HECO-IR-1[27] were developed prior to the unprecedented global and local events of the COVID-19 pandemic and therefore do not include impacts of the virus on the forecasts. The Company updated its forecasts to account for the impacts of COVID-19 as presented in the August 31, 2020 FAWG meeting and described further in Appendix C: Forecast Methodologies.[28] Feedback from stakeholders on the assumptions used to develop the forecasts and the resulting forecast were an important part of the process and are summarized in *IGP Stakeholder Feedback Summary, March 2021*. Additional updates made based on recent stakeholder engagement in response to the Review Point Guidance are described throughout this document.

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 Appendix C: Forecast Methodologies. 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's own assumptions, as shown in the table below.

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26 *See* https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/forecast_assumptions/20190717_wg_fa_meeting_presentation_materials.pdf, slides 10-12.

27 *See* https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/forecast_assumptions/dkt_20180165_20200702_HECO_response_to_PUC_IRs_1-2.pdf

28 *See* https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/forecast_assumptions/20200831_wg_fa_meeting_presentation_materials_HECO.pdf, slides 6, 9, 11, 13 and 16 for O'ahu, Maui, Moloka'i, Lāna'i and Hawai'i islands respectively.

Table 4-1: Input Data Sources for Underlying Forecast

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
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

4.1.1 Distributed Energy Resource Forecasts

Through the STWG, the DER Docket proceeding, and other meetings, the DER forecasts have been updated, including the development of a high and low forecast for the bookend sensitivities. Several stakeholder suggestions were made at the June 17, 2021 STWG meeting[29] to develop bookend DER forecasts and revisions to the base scenario. Stakeholder comments included:

- There are pockets of schedule-R (multi-family residences) that are not currently reachable in the DER market, and this has more to do with a lack of available programs for these customers. It's more of a policy issue than a DER supply issue. Specifically, there are AOAOs that are not currently reachable.
- For the bookend, one way is to remove the addressable market constraints.
- Are we looking at bookends from the perspective of capturing untouched markets, such as rental properties? How much DER should be included in load versus how much is export?
- It seems to make sense as a realistic possibility [to extend tax credits].
- In the longer term, it is reasonable to consider an export program extension in the base case as well as in the high bookend scenario.

[29] Available at, https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/igp_meetings/20210617_stwg_meeting_notes.pdf

As a direct result of this feedback, Table 4-2, below summarizes the changes and assumptions the Company made in the development of the updated DER forecasts.

Table 4-2. 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), expanded addressable market	Revised uptake based on DER docket proposals (DER Parties), include EDRP, updated resource costs, 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%

Input	No State ITC	Low	Base	High
Add-Ons	NEM+	NEM+	Sch-R NEM above minimum bill customers from 2021-2023 (Oahu, Maui), NEM+[30]	Sch-R NEM customers from 2021-forward

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. Future DER capacity modeling considered two-time horizons:

- Near term (next one to three years) reflects the current pace of incoming applications and executed agreements, existing program (NEM, NEM+, SIA, CGS, GSP, CSS and ISE)[31] subscription level and caps, feedback from the Companies' program administrators and 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 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 simple payback considers a set of assumptions such as the installed cost of PV and battery, installation 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. The addressable market, or the number of utility customers that have the potential to install a DER behind the meter is also considered.

Another important assumption to consider was the structure of programs. There is an array of program choices today, some of which are subject to capacity caps. Assumptions were made as to the structure of future programs for the long term after obtaining input and perspectives from program

[30] 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.

[31] 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.

administrators/designers, industry, and policy/consultancies. The future new tariff is assumed to have compensation for export[32] that is aligned with system needs and allows for controllability during system emergencies. The export compensation and tariff structure was based on the Standard DER Tariff for all islands proposed by the Company in the DER docket[33]. Insight from the DER panel members on the Panel of Experts meeting held on March 22, 2019 as well as already interconnected systems, applications and permit data show that customers are choosing to use battery storage to shift their generation to offset their own load rather than exporting to the grid during the daytime. In addition, for O'ahu and Maui, the DER forecast also incorporated the Emergency Demand Response Program (EDRP), Scheduled Dispatch program[34], and assumed that an upfront incentive of $250/kW would continue to be available beyond EDRP for new DER customers in exchange for provision of grid services (i.e., bring your own device programs) as part of a long-term DER program. Consistent with the EDRP, incentives would be paid based on performance and commitment of the customer resource.

Under the EDRP assumption, DER customers are modeled to export at the battery system's rated capacity [kW] (if energy is available) for a two-hour duration during the evening peak window, 5 PM to 9 PM, each day.

NREL 2021 Annual Technology Baseline (ATB) forecasts storage continues to decline in cost and it seems likely that compensation for daytime export will continue to be relatively low compared to retail rates, therefore the assumption was made that most future systems under the future tariff will be paired with storage. Furthermore, the rollout of a broad opt-out time-of-use (TOU) rate would increase the incentive to pair future systems with storage, adding additional credence to this assumption. Hawaiian Electric is including high and low scenarios, to test different rates of technology adoption by customers. Since advanced rate designs and long-term distributed energy resource programs are in the process of being finalized and implemented, the Companies will take a "best guess" approach to assume high and low levels of ~~TOU~~ DER adoption within the high and low scenarios.

These assumptions based on stakeholder feedback and information from the DER Docket proceeding, represent the collective best guess from all

[32] *See* Order No. 37066 issued on April 9, 2020 in Docket No. 2019-0323, Instituting a Proceeding to Investigate Distributed Energy Resource Policies pertaining to the Hawaiian Electric Companies.

[33] *See* Hawaiian Electric's DER Program Track Final Proposal filed on May 3, 2021 in Docket No. 2019-0323, Instituting a Proceeding to Investigate Distributed Energy Resource Policies pertaining to the Hawaiian Electric Companies.

[34] *See* Order No. 37816 issued on June 8, 2020 in Docket No. 2019-0323, Instituting a Proceeding to Investigate Distributed Energy Resource Policies pertaining to the Hawaiian Electric Companies.

stakeholders. Though, potential impacts from adjustments made to these assumptions may not necessarily require restating the forecast since the "spread" between the low, base, and high forecast should sufficiently capture any impacts within the bounds of the forecasted sensitivities.

The current rate of DER applications and remaining capacities to reach set caps of interim programs, coupled with recent system configuration trends in DER applications were used to set the pace, capacities and amount of PV systems paired storage in the near term. The increasing trends in PV systems paired with batteries was observed among recent DER applications. The forecasted ramping up of paired storage systems was also supported from feedback received during the Panel of Experts meeting held on March 22, 2019 from industry leaders.[35] For residential systems in the near-term, the number of systems paired with storage increased from roughly 60% to as high as 95% for some islands in 2022. Similarly, the small and medium commercial classes had a ramping up of paired storage systems through the course of the near term to meet with the assumptions of the model that picks up after the near-term.

The model assumptions were that all small and medium commercial and all residential systems will be paired with storage after the near-term forecast. 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 in the case of EDRP, export to the system) during the peak period on a daily basis. As a result, these 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. PV installs for large commercial customers were modeled without battery storage.

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 more accurately reflect monthly variations in the energy production of DER systems. A degradation

[35] *See* https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/forecast_assumptions/20190522_wg_fa_meeting_presentation_materials.pdf

factor of 0.5% a year[36] was applied to the sales impacts to recognize that the DER system's performance degrades over time.

For incentives, the following was assumed for Federal and State investment tax credits.

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

Table 4-3: 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 4-4: 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

One of the key drivers in the long-term DER forecast is the addressable market, including customers that can add-on to existing systems. Expanding the addressable market compared to the original IGP market forecast assumption was a common theme from stakeholders. 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 4-5~~Table 4-5~~. 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.

[36] 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

Stakeholders commented on the addressable market for DER customers at the June 17th, 2021 Stakeholder Technical Working Group meeting and June 28th, 2021 DER Docket Status Conference. For example, at the DER Docket Status Conference, stakeholders commented retrofitting existing DER customers with added PV capacity and battery systems would likely be the most attractive option to meet the EDRP's 50 MW target. On June 8th, 2020, the Commission issued Order No. 37816 in Docket No. 2019-0323 approving the EDR Program and Scheduled Dispatch rider for new and existing DER customers.[37] Considering the comments and feedback provided by stakeholders and Order No. 37816, 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, Table 4-6. In addition, comments from stakeholders indicated that there might be DER customers who only install on 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[38].

Table 4-5: 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 4-6: 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

[37] *See* Order No. 37816 issued on June 8, 2020 in Docket No. 2019-0323, Instituting a Proceeding to Investigate Distributed Energy Resource Policies pertaining to the Hawaiian Electric Companies.

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

For commercial customers, public and private building ownership was considered. Structures greater than six stories were excluded. Similar to residential customers, small and medium commercial consumption needed to be above a set threshold. Commercial thresholds were established using rate class customers' previous 12-months usage, historical PV installation data, and business types. PV and non-PV customers were segmented by business type and distributions for total usage[39] 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 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 4-7~~Table 4-7~~ through Table 4-10~~Table 4-10~~.

Table 4-7: 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 4-8: 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

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

Table 4-9: 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 4-10: 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)	(KWH)
O'ahu	78%	330.0	0.0
Hawai'i	44%	64.0	0.0
Maui	68%	330.0	0.0

Table 4-11: Cumulative Distributed PV Capacity (kW)

Year	O'ahu	Hawai'i Island	Maui	Moloka'i	Lāna'i	Consolidated
kW	A	B	C	D	E	F =A + B + C + D +E
2025	723,234	138,801	158,260	3,200	1,050	1,024,545
2030	830,974	164,392	185,501	3,696	1,356	1,185,919
2040	993,411	209,179	227,968	4,476	1,888	1,436,922
2045	1,053,934	227,449	242,917	4,768	2,085	1,531,153
2050	1,104,843	243,258	255,327	4,952	2,226	1,610,606

Table 4-12: Cumulative Distributed BESS Capacity (kWh)

Year	O'ahu	Hawai'i Island	Maui	Moloka'i	Lāna'i	Consolidated
kWh	A	B	C	D	E	F =A + B + C + D +E
2025	317,754	84,230	128,263	1,348	515	532,110
2030	493,412	126,316	179,030	2,308	875	801,941
2040	756,521	196,611	254,943	3,976	1,550	1,213,601

2045	848,456	224,301	282,258	4,588	1,829	1,361,432
2050	923,096	247,272	303,603	5,068	2,072	1,481,111

High and Low Bookend Sensitivities

To support the bookend scenarios, the Company sought additional feedback to derive assumptions for the DER sensitivities. At the June 17, 2020 STWG meeting, stakeholders provided comments on removing the addressable market constraints to account for the possibility for faster customer adoption and support the High DER sensitivity. As a result, the addressable market was expanded beyond to the Base case to include all existing NEM customers from 2021 through 2050. Additionally, the High DER sensitivity further extended the addressable market by removing the owner-occupied requirement, increasing the multi-family unit size threshold from 4 to 49 units, and included 100% of Schedule-P customers.

The Company also sought stakeholder feedback regarding future incentive structures. At the June 17, 2021 STWG meeting, the Company requested input on the possibility of extended tax credits and a longer-term export program. Stakeholders responded that both seem to be realistic possibilities. Although an extension of the Federal investment tax credit is still unknown with the current information available on the bipartisan infrastructure plan, the Company extended the Federal investment tax credit through 2032, with residential investment tax credits ending and commercial investment tax credits settling at 10% in 2033. The long-term upfront incentives for future grid services program on all islands were also increased to $500/kW for the high DER forecast.

At the June 2, 2021 STWG meetings, stakeholders commented on the advancement of technology and supply chains that may drive down the costs of DER systems. In response, the Company used NREL 2021 ATB – Advanced Scenario cost curves for residential and commercial PV and battery systems for the High DER sensitivity forecast. The ATB – Advanced Scenario assumes a rapid advancement in technology innovation and manufacturing at levels above and beyond the current market. Resulting from the ATB – Advanced Scenario are more aggressive PV and battery system costs curves compared to the ATB – Moderate Scenario.

The Company re-purposed the previous July 2020 IGP base/market DER forecast as the Low DER sensitivity and as the basis for the No State ITC sensitivity. The No State ITC sensitivity was modeled assuming a 0% State ITC starting in 2022, resulting in lower DER uptake compared to the market forecast. In both sensitivities, DER system costs and tax credit assumptions were updated similarly to the current Base case, as shown in Table 4-2.

As a direct result of stakeholder input, Figure 4-1~~Figure 4-1~~, below illustrates the revised DER forecasts.

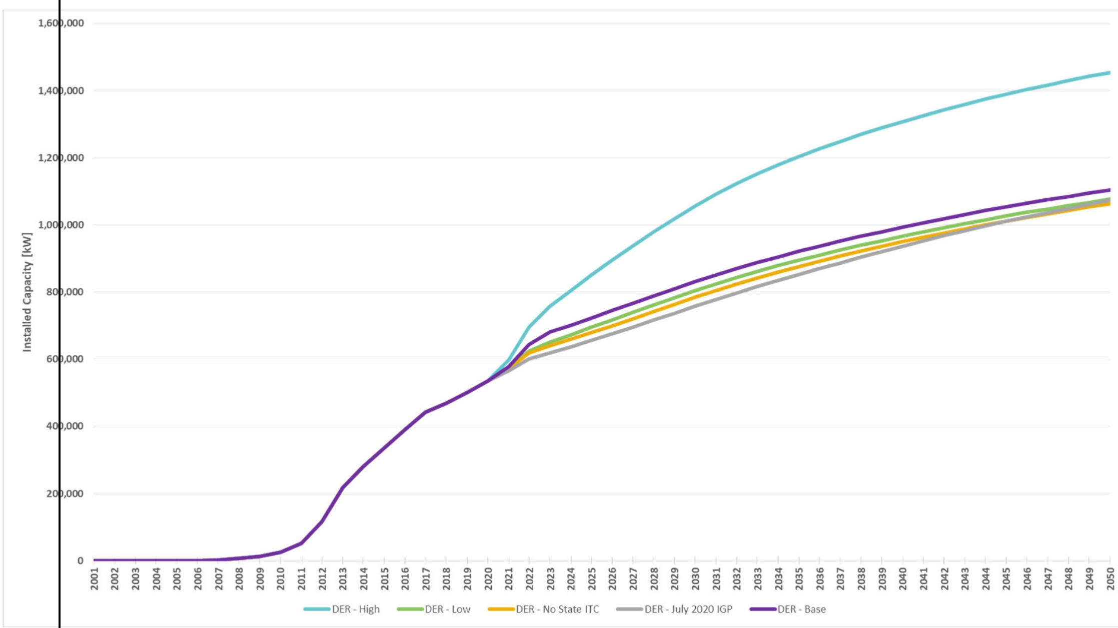

Figure 4-1: Oʻahu DER Bookend Sensitivities

Advanced Rate Design Impacts

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 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 discharg~~eing~~ the system in the evening. This load shifting is captured in the DER forecasts battery storage profiles.~~,~~ ~~and in~~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~~cases,~~ customers charging electric vehicles during the day in response to TOU rates.

At the June 17, 2021 STWG, stakeholders asserted that the additional demand charge under the Company's ARD proposal would affect the forecasted DER uptake. Under the current ARD proposal, 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[40], 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 also 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.

~~As discussed in its Workplan update letter to the Commission filed on July 28, 2021, the~~The Company ~~is further evaluating~~evaluated TOU load shifting impact for non-DER customers and non-EV ~~customers~~load.~~ The Company will provide an update on this issue no later than the October 1, 2021 Review Point filing~~ Key takeaways from the Companies' literature review and preliminary estimated load shift for residential customers were presented to the STWG on September 23, 2021[41].~~-~~ 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. Stakeholders suggested that TOU rates from the DER Parties final ARD proposal ~~chould~~could be used to create a high scenario. Based on the proposal presented and stakeholder input, assumptions in Table 4-13 were used to develop TOU load shift scenarios for residential customers.

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[40] *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.

[41] September 23, 2021 STWG presentation slides 5-8, 20-22. *See* https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/stakeholder_technical/20210923_stwg_meeting_presentation_materials.pdf

Table 4-13. 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[42]	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

For commercial customers' TOU load impact, stakeholders commented that although the UHERO study[43] referenced in the presentation provided insights on Hawaii commercial customers' potential to participate in and benefit from TOU rates, it was itself a literature review and not a pilot study, therefore limited in its ability to predict impacts. Stakeholders asked the Companies to review studies from California to evaluate whether assumptions applicable to Hawaii commercial customers could be gleaned from results in California.

On October 1, 2021, the Consumer Advocate ("CA") ~~filed~~submitted comments to the Company on the TOU analysis presented in the September 23, 2021

[42] Timing of AMI meter rollout is addressed in the Companies' response to PUC-IR-119c, Docket No. 2018-0141. *See* https://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A21I08A90420A00180

[43] Wee, S. and Coffman, M. (2018). Integrating Renewable Energy: A Commercial Sector Perspective on Price-Responsive Load-Shifting. UHERO Report. *See* https://uhero.hawaii.edu/integrating-renewable-energy-a-commercial-sector-perspective-on-price-responsive-load-shifting/

STWG[44], provided in Appendix F. 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 Aigner and Hirschberg (1985),[45] 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 has 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."[46] 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."[47] 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)[48] study was conducted in 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

[45] 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.

[46] At 349

[47] At 352

[48] 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.

a major portion of the system load."[49] The conditions of the study are not comparable to conditions in Hawaii.

The California Statewide Pricing Pilot (SPP)[50] 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.[51] 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."[52] 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.

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~~a voluntary or~~ opt-out commercial TOU rate in and of itself will result in load shifting. The Company will evaluate the response of commercial customers that are assigned ARD TOU rates, once approved. This information may be used to inform forecasts in future IGP cycles. –The Company will review expanding the existing demand response programs that could complement the enablement of commercial load flexibility. ~~The~~A potential demand response expansion will be based on the existing demand response potential study that was last performed in 2016 under Docket No.

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[49] At 418

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

[51] At 119-120

[52] At 13

2015-0412 and needs currently identified. Upon ~~the~~ completion of the Grid Needs Assessment~~grid assessment~~, the Company may update the potential study ~~based on~~if new grid services are identified that are not addressed in the existing demand response potential study.~~that grid may require going forward.~~

~~However, t~~The Company believes that the high and low bookend scenario ~~already~~ provides significant load shaping; for example, see Figure 4-5. Any unanticipated impacts of ~~increased demand charges~~rate design changes or behavioral changes for customers without EV or DER will be captured within the bookends. The uncertainty of these and other future changes in customer trends are precisely what the bookends are intended to capture such that any changes that may occur, that impact the net demand, would fall within the bookends.

~~*High and Low Bookend Sensitivities*~~

~~To support the bookend scenarios, the Company sought additional feedback to derive assumptions for the DER sensitivities. At the June 17, 2020 STWG meeting, stakeholders provided comments on removing the addressable market constraints to account for the possibility for faster customer adoption and support the High DER sensitivity. As a result, the addressable market was expanded beyond to the Base case to include all existing NEM customers from 2021 through 2050. Additionally, the High DER sensitivity further extended the addressable market by removing the owner-occupied requirement, increasing the multi-family unit size threshold from 4 to 49 units, and included 100% of Schedule-P customers.~~

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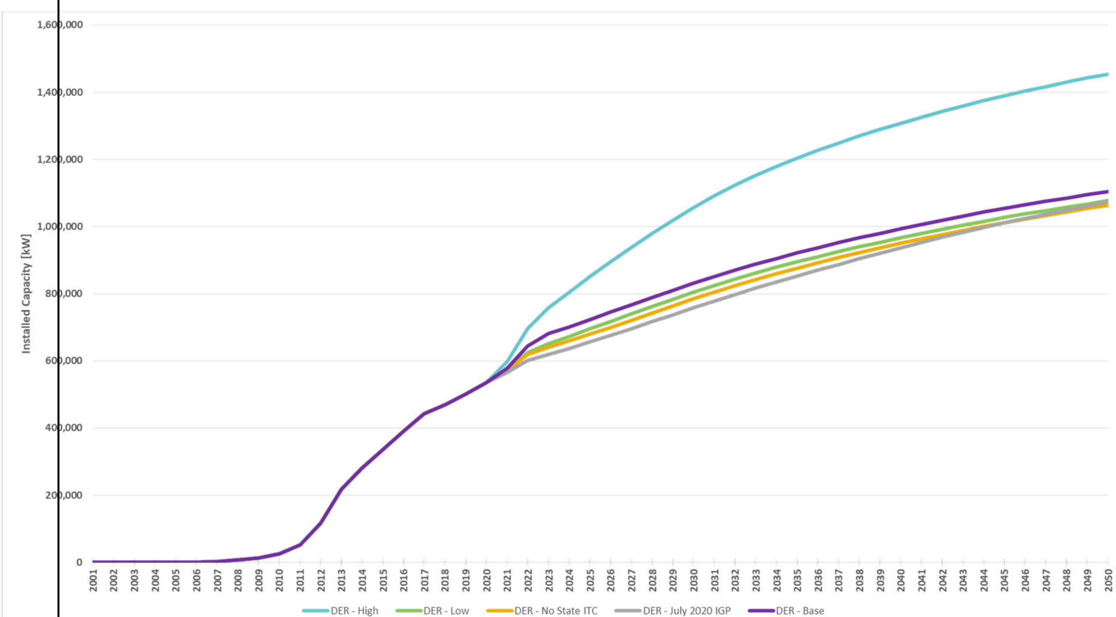
~~rapid advancement in technology innovation and manufacturing at levels above and beyond the current market. Resulting from the ATB – Advanced Scenario are more aggressive PV and battery system costs curves compared to the ATB – Moderate Scenario.~~

~~The Company re-purposed the previous July 2020 IGP base/market DER forecast as the Low DER sensitivity and as the basis for the No State ITC sensitivity. The No State ITC sensitivity was modeled assuming a 0% State ITC starting in 2022, resulting in lower DER uptake compared to the market forecast. In both sensitivities, DER system costs and tax credit assumptions were updated similarly to the current Base case, as shown in Table 4-2.~~

~~As a direct result of stakeholder input, Figure 4-1, below illustrates the revised DER forecasts.~~



~~Figure 4-1: O'ahu DER Bookend Sensitivities~~

4.1.2 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.[53] The preliminary results

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

from the study were presented to the FAWG on January 29, 2020.[54] 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.

An achievable Business As Usual (BAU) energy efficiency potential forecast by island and sector covering the years 2020 through 2045 was provided to the Company in February 2020 to use for the Company's forecasts. The BAU potential forecast 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 Achievable - High potential forecast assumed higher levels of savings and participation through expanded programs, new codes and standards, and market transformation.

The forecasts provided to the Company reclassified certain market segments to different customer classes to align with how the Company forecasts sales. Since a thirty-year forecast was needed, the Company extended the forecast out to 2050 using trends in AEG's forecast. AEG's forecast for Lānaʻi and Molokaʻi was adjusted to be consistent with Hawaii Energy's historical island allocation. A five year average net-to-gross ratio from Hawaii Energy's program years 2014 through 2018 for each island was applied to the forecasts in order to exclude free riders[55] from the energy savings estimates as impacts from free riders were assumed to be embedded in the underlying forecasts described above. 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 ramped 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.

High and Low Bookend Sensitivities

The additional energy efficiency potentials provided by AEG allowed for the creation of various forecast sensitivities. As a result, the Company developed

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[54] *See* https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/forecast_assumptions/20200129_wg_fa_hawaii_market_potential_study_draft_results.pdf

[55] A free rider is someone who would install an energy efficient measure without program incentives.

three different sensitivities, Low, High, and Freeze. These sensitivities were presented on July 9, 2021 with a smaller group of stakeholders and at the July 14, 2021 STWG meeting. The following Table 4-~~Table 4-13~~ and Figure 4-2 summarize the energy efficiency sensitivities and their forecasted annual sales [GWh].

Table 4-~~13~~14: Energy Efficiency Bookend Sensitivities

Low	Base	High	Freeze
BAU only	BAU + C&S	Achievable High + C&S	Forecasted capacity fixed at 2021 Base forecast

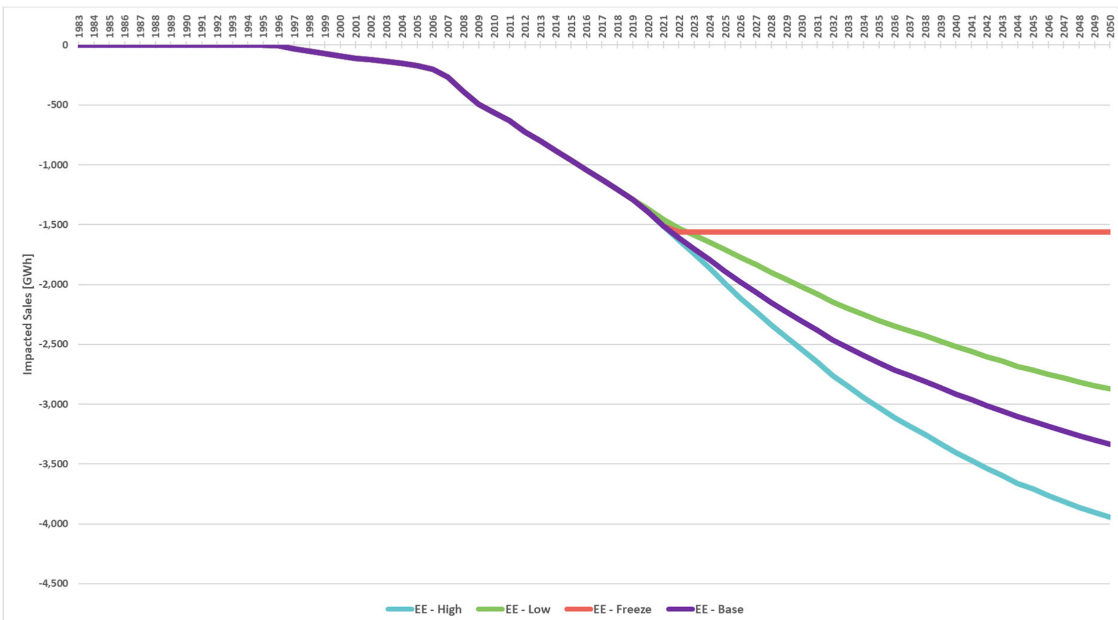


Figure 4-2: O'ahu Energy Efficiency Annual Sales Forecast Impact Sensitivities

As summarized in Section 2.2, the Company has already met with AEG to discuss the scope of work to bundle energy efficiency measures into resource options for selection by RESOLVE, in addition to and separate from the minimum uptake of energy efficiency that is assumed through the forecast layers. Draft supply curves for the energy efficiency resources will be shared with stakeholders once developed.

4.1.3 Electrification of Transportation

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

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[56] to arrive at EV saturations of total light duty vehicles (LDV) by year for each island. Historical data for LDV registrations were provided by the Department of Business, Economic Development, and Tourism (DBEDT) and reported at the county level. In order to get to the island level for Maui County, an allocation factor supplied by DBEDT and based on vehicle registration for the three islands was used. The total LDV 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 EV 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 LDV forecast for each island to arrive at the number of light duty EVs.[57] Although EV saturations were not specifically consistent with carbon neutrality in Hawaii by 2045, 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:

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

where

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

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

[57] *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

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.[58] For Lāna'i and Moloka'i, vehicle miles travelled were developed based on information from DBEDT and on-island sources.

Historical *kWh per mile* was obtained using the weighted average fuel economy of registered electric vehicles by island. For Lāna'i and Moloka'i, 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[59]. *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.[60] The reference fuel economy growth rate was developed based on the expectation that battery technology will improve and 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, the Company used a ratio between residential and commercial PV installations in historical years to allocate the number of EVs between residential and commercial customers for each island. EVs were a relatively new technology and the number of PV installations were found to be correlated to EV adoption. 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 arrive at 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.

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

58 *See* https://www.fhwa.dot.gov/policyinformation/tables/vmt/vmt_forecast_sum.pdf

59 *See* http://www.fueleconomy.gov

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

the Company's DC fast charging network and a case study[61] conducted through the deployment of EnelX's Level 2 chargers in Hawai'i. Figure 4-3 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. The revised charging profiles were presented on July 9, 2021 with a smaller group of stakeholders and again at the July 14, 2021 STWG meeting.

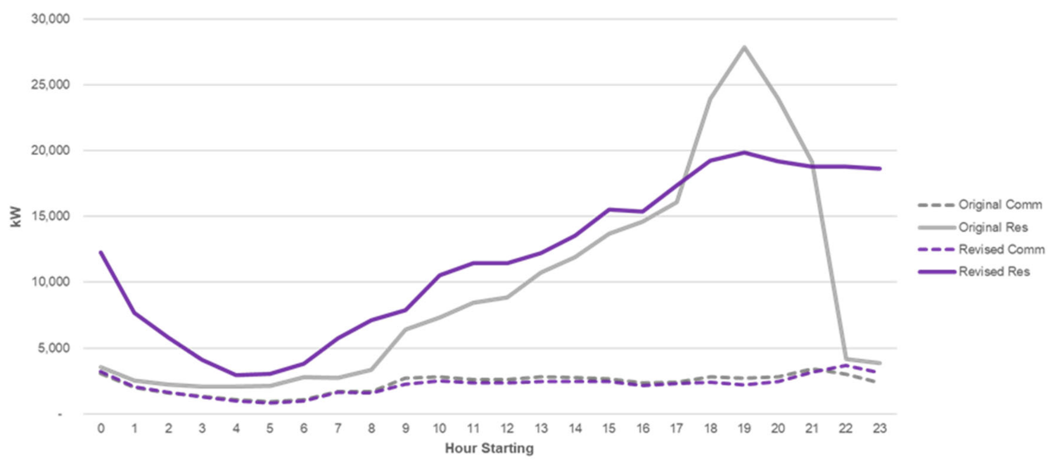


Figure 4-3: Revised Light Duty Electric Vehicle Charging Profiles

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, the Company 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.

High and Low Bookend Sensitivities

Three additional light duty electric vehicle forecast sensitivities (Low, High, and Freeze) were developed using varying adoption saturation curves. Low and high saturation curves were presented at the August 27, 2019 and January 20, 2020 FAWG meetings, with the low saturation curve implemented for the Low

[61] *See* Smart Charge Hawai'i Case Study, In partnership with Hawaiian Electric & Elemental Excelerator, EnelX

EV sensitivity. At the June 17, 2021 STWG meeting, Blue Planet presented their suggested sensitivity representing a policy of 100% zero emissions vehicles by 2045 in the high customer technology adoption bookend, a change from the previously presented high saturation curve. Following that meeting, Blue Planet provided two forecast scenarios as suggestive references for a 100% ZEV on the road scenario. The first was the Transcending Oil Report prepared by the Rhodium Group in 2018. The Transcending Oil Report study considered vehicle scrappage rates and the transition rate of vehicle sales to fully electric. The study estimated all vehicle sales by 2030 would need to be electric to reach 100% electric vehicle stock by 2045.[62] The second was Blue Planet's self-developed estimate using the State Energy Office's Monthly Energy Trends data and a regression for the past 5 years on electric vehicle registrations. As discussed in Section 2.4 regarding areas of disagreement, Blue Planet most recently provided a revised high forecast that tracks closely with the Transcending Oil Report EV forecast. Ultimately, the High sensitivity used the 100% ZEV saturation scenario provided in the Transcending Oil Report. A freeze sensitivity was also developed, assuming no new additional electric vehicles above the Base forecast after 2021. These sensitivities were presented on July 9, 2021 with a smaller group of stakeholders and at the July 14, 2021 STWG meeting. The following Table 4-~~Table 4-14~~ and Figure 4-4 summarize the light duty electric vehicle sensitivities and their forecasted annual sales [GWh].

Table 4-~~14~~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

[62] 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

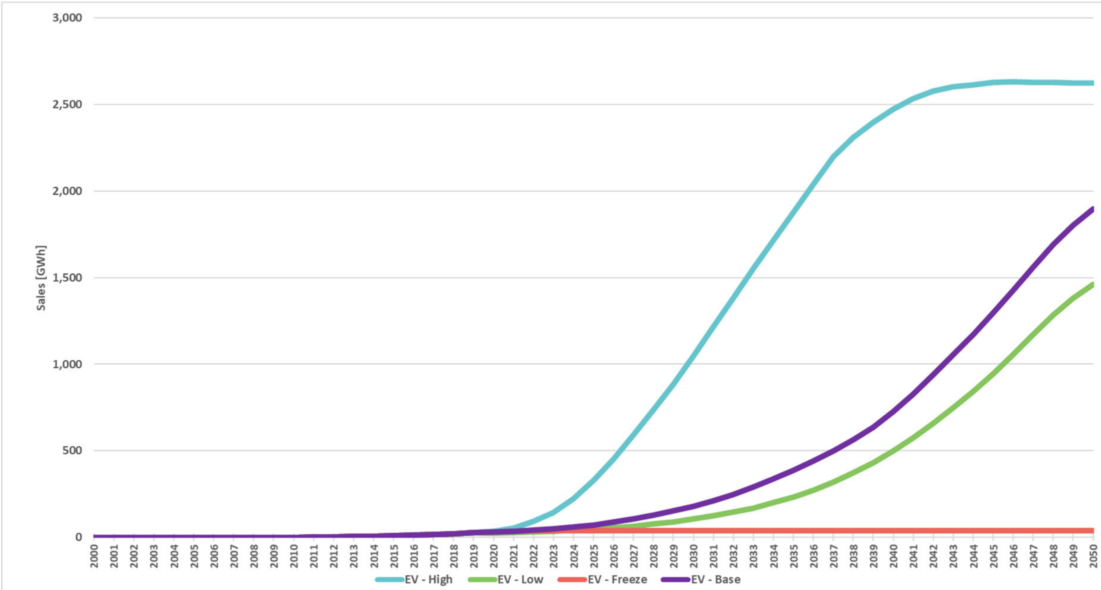


Figure 4-4: O'ahu Electric Vehicle Annual Sales Forecast Sensitivities

4.1.4 Managed Electric Vehicle Charging

The managed electric vehicle charging profile considers EV driver response to time of use rates that were proposed for each island in the EV pilot programs in Docket No. 2020-0152. E3's linear optimization was used to model drivers who shift their usage in order to reduce their electricity bill as much as possible, while still retaining enough state of charge to meet their underlying driving profiles. The underlying trip data is the same so the managed and unmanaged charging have the same annual loads. The managed charging profiles from the I&A Review Point showed a flatter profile. E3 has since provided updated managed charging profiles based on their model, which shifts for of the charging load during the daytime. The updated average managed EV charging profile for select years is provided for O'ahu in Figure 4-5 below.

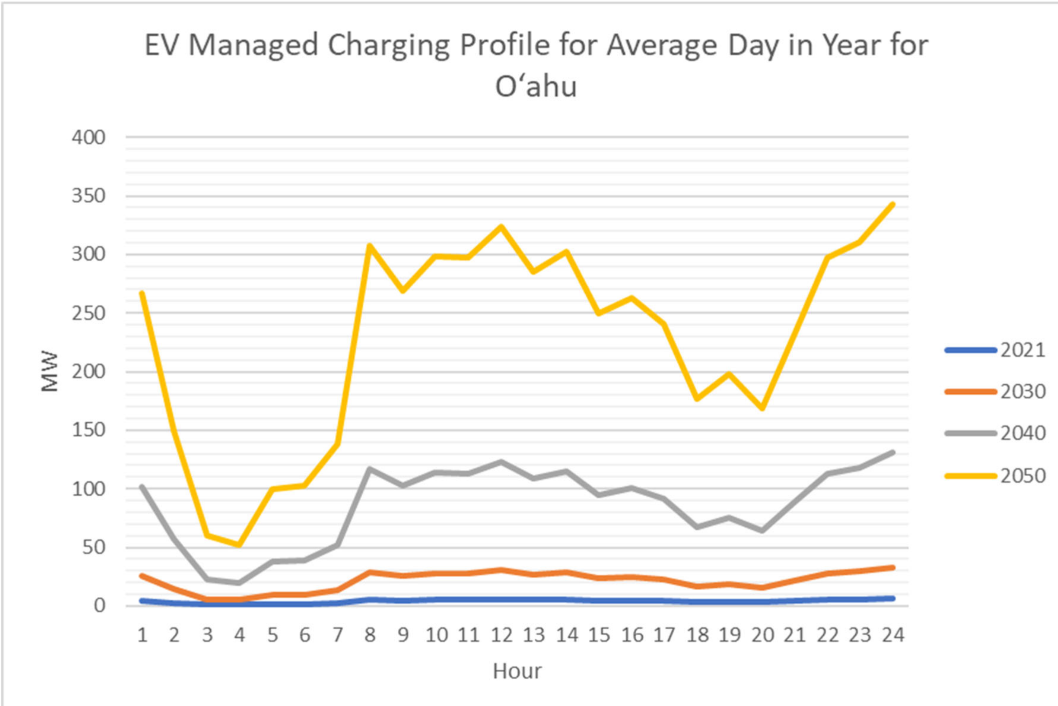


Figure 4-5: Average Managed EV Charging Profile for O‘ahu

4.2 SALES FORECASTS

Once all the layers are developed for each island, they are added together to arrive at the sales forecast at the customer level by island as shown in the following tables.

Table 4-~~15~~16: O‘ahu Sales Forecast

Year	Underlying	Distributed Energy Resources (PV and BESS)	Energy Efficiency	Electric Vehicles	Customer Level Sales Forecast
GWH	A	B	C	D	E =A + B + C + D
2025	9,456	(1,255)	(1,887)	92	6,407
2030	10,133	(1,415)	(2,307)	221	6,632
2040	11,110	(1,642)	(2,917)	789	7,341

2045	11,499	(1,707)	(3,142)	1,366	8,016
2050	11,905	(1,756)	(3,332)	1,964	8,781

Table 4–~~16~~17: Hawai'i Island Sales Forecast

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

Table 4–~~17~~18: Maui Sales Forecast

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

Table 4-~~18~~19: Moloka'i Sales Forecast

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

Table 4-~~19~~20: Lāna'i Sales Forecast

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

The customer level sales forecasts were compiled by incorporating the separate layers for the underlying, distributed energy resources, energy efficiency, and electric vehicles sales. The Base forecast would incorporate the base forecast for each of the layers. In the Company's proposal for Customer Technology Adoption bookends, the high layers would be added together to create a high bookend. Similarly, the low layers would be added together to create a low bookend. This process would incorporate layers that have offsetting effects on sales i.e. high DER and EE layers would reduce sales and offset the increased sales of the high EV layer. When compiling the sales layers, separate sales forecasts were also developed to incorporate a combination of layers that purposefully lead to high and low sales. In the charts below, Figure 4-6 through Figure 4-10, the High and Low Customer Technology Adoption sales forecasts are shown in teal and green, labeled as High Adoption and Low Adoption, respectively. Separately, the high and low load sales forecasts are shown in shades of orange, labeled as High Load and Low Load, respectively.

Upon review of these sales forecasts, the Low Customer Technology Adoption bookend was observed to track the Base forecast and was not significantly different to serve as a bookend. Similarly, the High Customer Technology Adoption bookend was observed to cross over the Low Customer Technology Adoption bookend and Base forecasts and would not serve as an appropriate bookend. However, the High Load and Low Load forecasts were significantly different from the Base forecasts, did not cross over other forecasts, and captured the High and Low Customer Technology Adoption forecasts within its bounds, making them a better candidate to serve as bookends. The selection of the High Load and Low Load scenarios is consistent with the TAP's recommendation to test the sensitivity of models and resulting portfolios by running bookend scenarios that utilize the cumulative potential high and low load forecasts for each layer. Section 6 further describes the adjustments made to the high and low bookends.

High and Low Bookend Scenarios

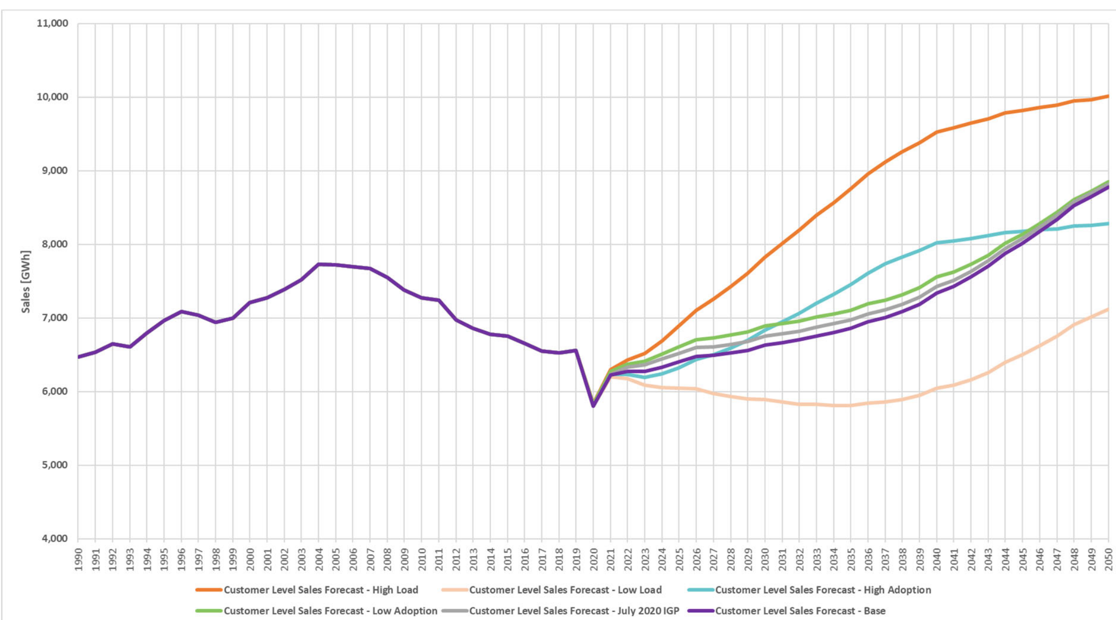


Figure 4-6: O'ahu Sales Forecast Bookend Sensitivities

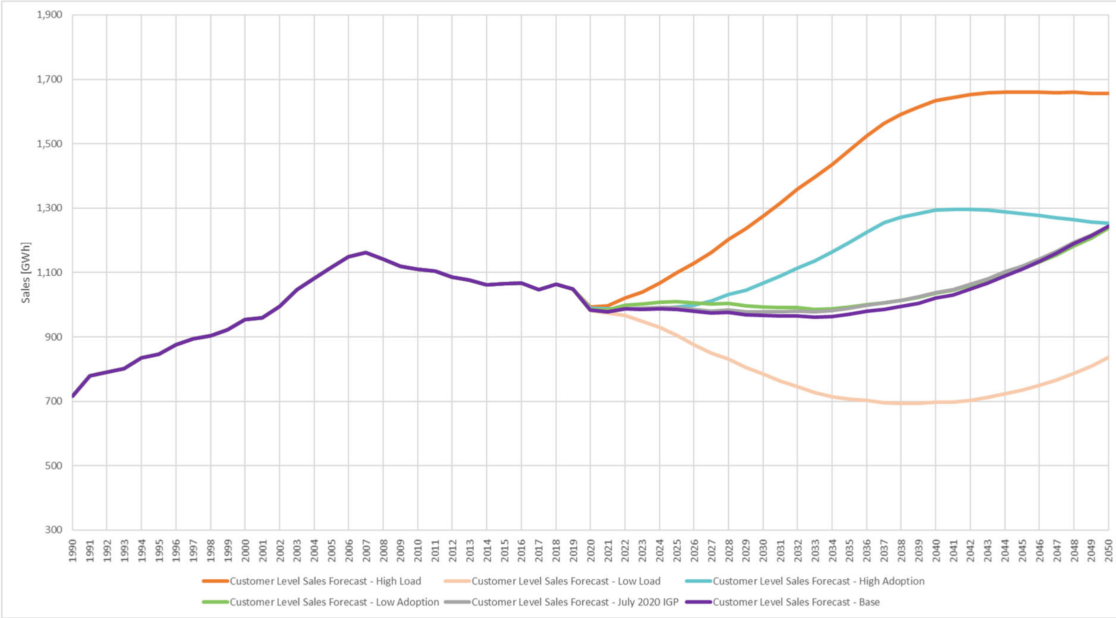
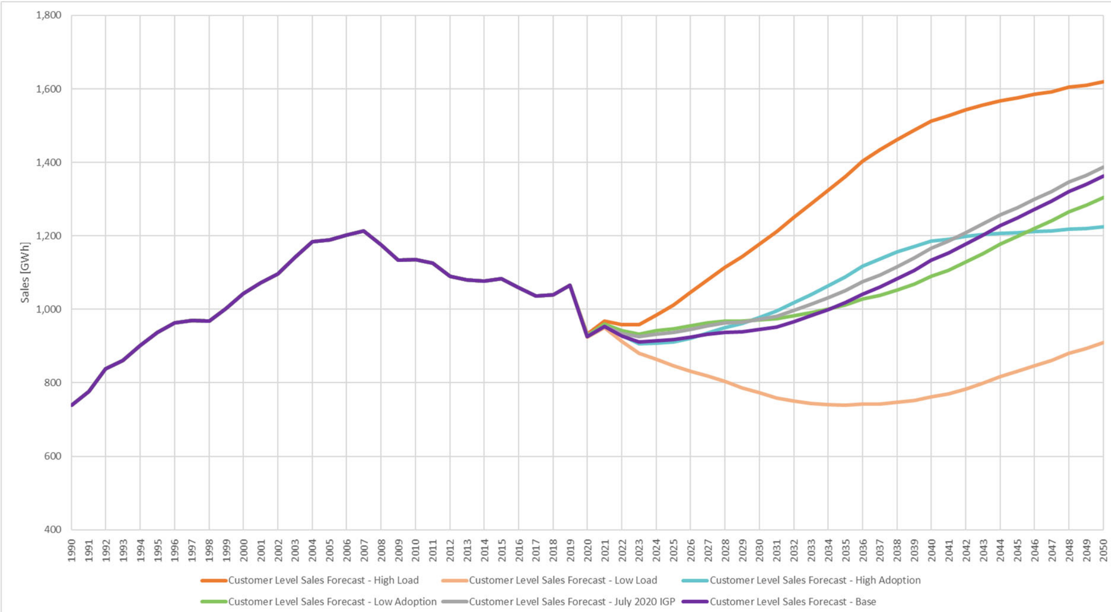


Figure 4-7: Hawai‘i Sales Forecast Bookend Sensitivities



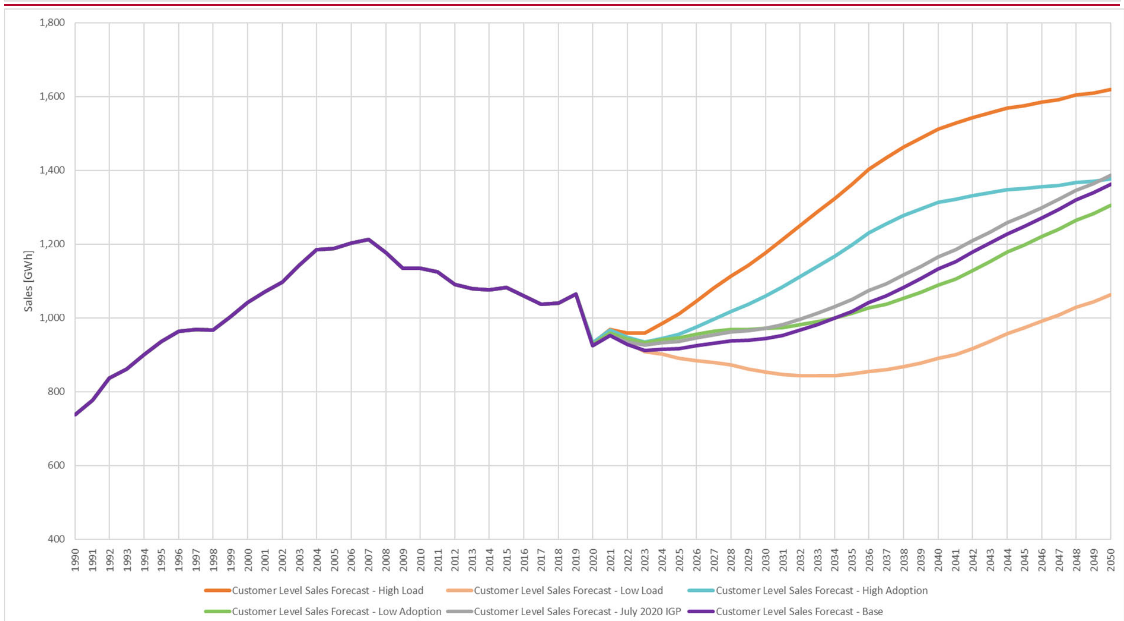


Figure 4-8: Maui Sales Forecast Bookend Sensitivities

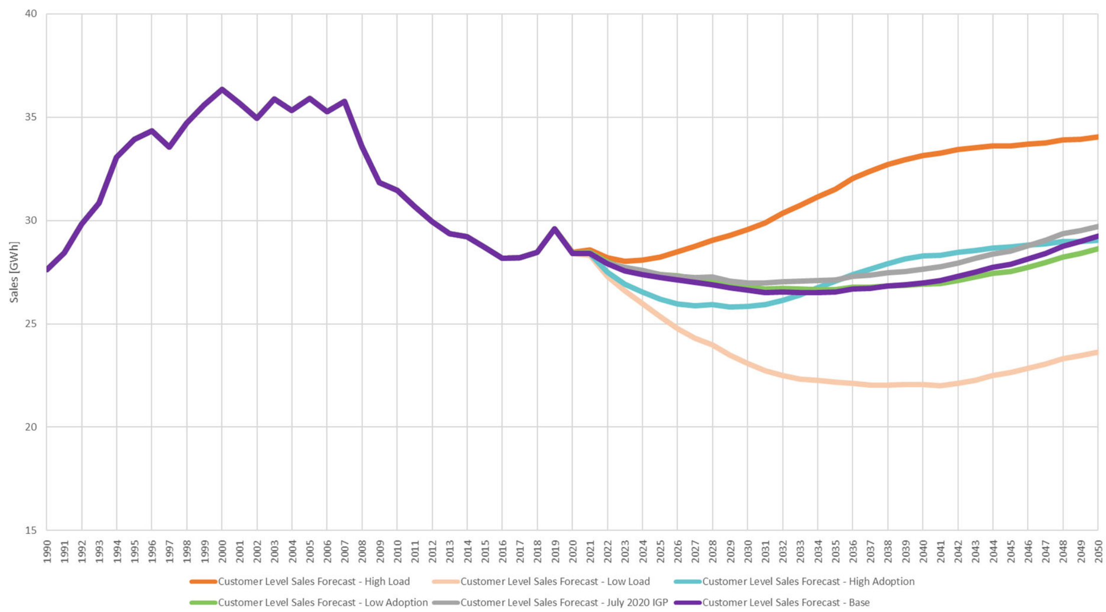


Figure 4-9: Moloka'i Sales Forecast Bookend Sensitivities

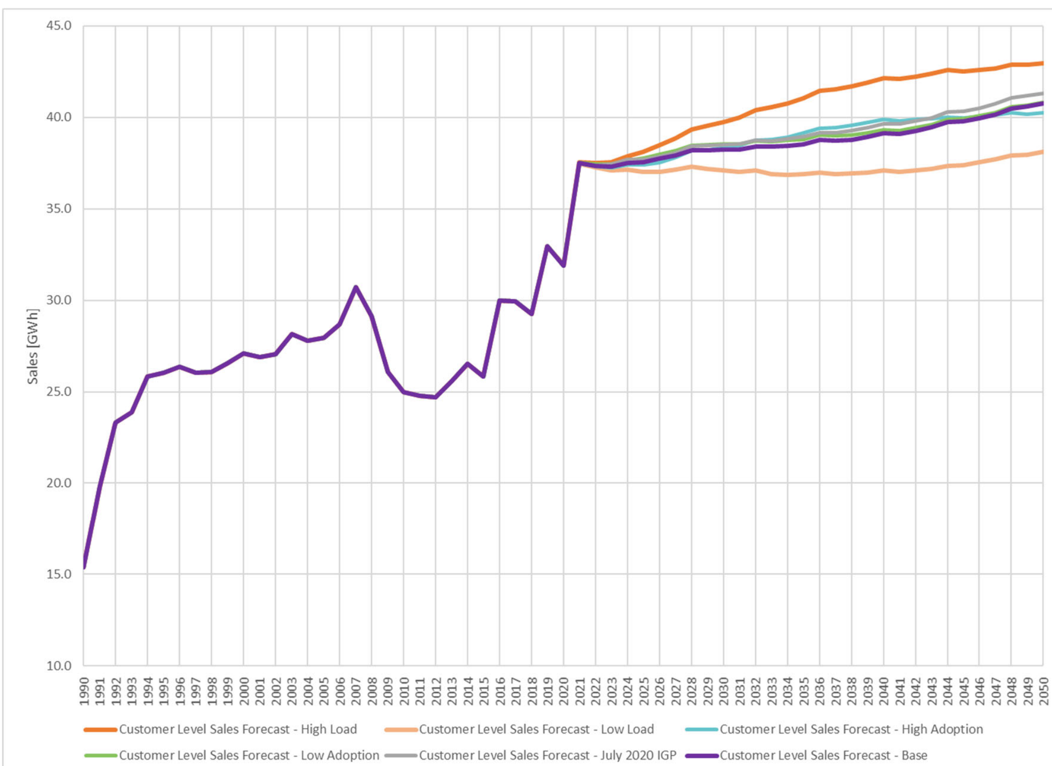
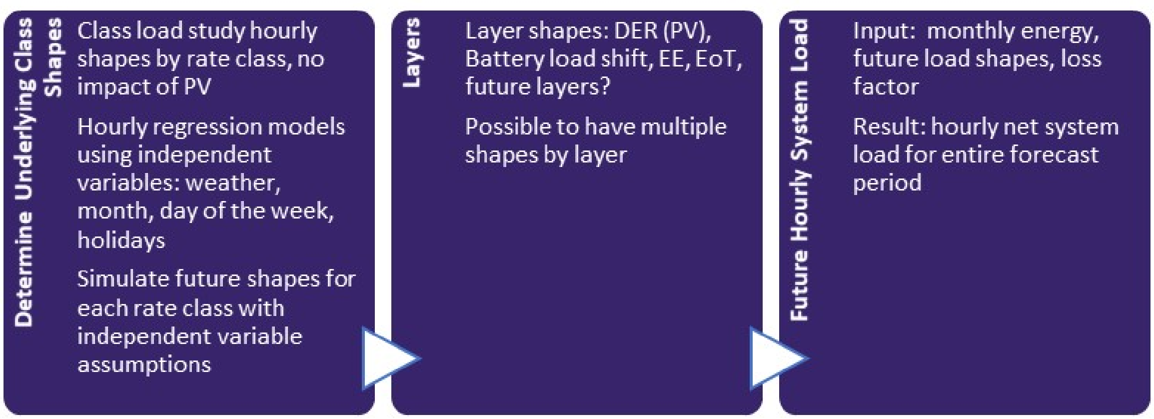


Figure 4-10: Lāna'i Sales Forecast Bookend Sensitivities

4.3 PEAK FORECASTS

Once the sales forecast is developed by layer (underlying, DER, EE and EoT) for each island, it is converted from a monthly sales forecast into a load forecast at the system level for each hour over the entire forecast horizon. The method to do the conversion from sales to an hourly load forecast is shown in the figure below. Hourly shapes from class load studies ("CLS") for each rate class or the total system load excluding the impact from PV are used to derive the underlying system load forecast shape. Hourly regression models are evaluated to look for relationships with explanatory variables (weather, month, day of the week, holidays) in order to accommodate change in the underlying shapes over time for each rate class or total system load. The hourly regression models are used to simulate shapes for the underlying forecast based on the forecast assumptions over the entire horizon. The forecasted energy for the underlying and each adjusting layer (DER PV, battery load shift, energy efficiency and EoT) is placed under its respective future load shape then converted from the customer level to system level using a loss factor[63] as presented in the July 17, 2019[64] and March 9, 2020[65] FAWG meetings.



The result is an hourly net system load for the entire forecast period.

[63] The net-to-system factor used to convert customer sales to system level load is calculated as equal to 1/(1-loss factor) and include company use. The loss factors are included below: - Oahu: 4.43% - Hawaii: 6.76% - Maui: 5.17% - Lanai: 4.39% - Molokai: 9.07%

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

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

Once all the forecasted layers are developed by hour for each island, they are combined to arrive at an aggregated hourly load forecast. The annual peak forecast is the highest value in each year. The peaks presented in the August 31, 2020 FAWG meeting include the impacts of COVID-19.[66] This forecast assumes EVs will be charged at each owner's convenience which may occur during the daytime on-peak period. This initial forecast will inform downstream processes in the development of programs and incentives related to shifting EV charging to off-peak periods. These programs and incentives will then be integrated into the forecast through an iterative process in the Grid Needs Assessment. As a result of this initial forecast which utilizes "unmanaged" charging, the peak contribution from EVs increases over time as EVs become more widely owned.

Table 4-~~20~~21: O'ahu Peak Forecast (MW)

Year	Underlying	Distributed Energy Resources (PV and BESS)	Energy Efficiency	Electric Vehicles	TOU	Peak Forecast
MW	A	B	C	D	E	F~~E~~ =A + B + C + D + E
2025	1,579	(60)	(339)	16	(3)	~~1,196~~1,193
2030	1,642	(95)	(402)	39	(5)	~~1,184~~1,179
2040	1,736	(87)	(454)	145	(4)	~~1,339~~1,335
2045	1,702	(43)	(452)	286	(4)	~~1,493~~1,490
2050	1,721	(51)	(477)	473	(4)	~~1,666~~1,661

Table 4-~~21~~22: Hawai'i Island Peak Forecast (MW)

Year	Underlying	Distributed Energy Resources (PV and BESS)	Energy Efficiency	Electric Vehicles	TOU	Peak Forecast
MW	A	B	C	D	E	~~E~~ F =A + B + C + D + E
2025	229.5	(10.0)	(42.6)	2.1	(1.3)	~~178.9~~177.6

66 *See* https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/forecast_assumptions/20200831_wg_fa_meeting_presentation_materials_HECO.pdf See slides 7, 10, 12, 14 and 17 for O'ahu, Maui, Moloka'i, Lāna'i and Hawai'i islands respectively.

2030	236.8	(12.5)	(55.5)	8.7	(1.5)	~~177.5~~176.0
2040	249.9	(10.8)	(84.2)	39.6	(2.2)	194.5192.3
2045	247.2	(3.4)	(85.3)	64.5	(1.9)	~~223.1~~221.2
2050	256.5	(3.8)	(99.6)	99.3	(2.1)	252.4250.3

Table 4-~~22~~23: Maui Peak Forecast (MW)

Year	Underlying	Distributed Energy Resources (PV and BESS)	Energy Efficiency	Electric Vehicles	TOU	Peak Forecast
MW	A	B	C	D	E	F~~E~~ =A + B + C + D + F
2025	246.7245.5	(18.0)	(47.3)	2.23.4	(0.8)	183.6182.7
2030	~~261.1~~260.0	(29.2)	(58.1)	~~11.4~~12.5	(1.2)	~~185.2~~184.1
2040	241.4240.1	(3.9)	(64.6)	63.364.5	(0.9)	236.2235.2
2045	~~255.4~~254.2	(4.1)	(67.7)	~~77.8~~79.0	(0.9)	~~261.4~~260.4
2050	260.3259.1	(16.8)	(71.2)	111.5112.7	(1.1)	283.8282.8

Table 4-~~23~~24: Moloka'i Peak Forecast (MW)

Year	Underlying	Distributed Energy Resources (PV and BESS)	Energy Efficiency	Electric Vehicles	TOU	Peak Forecast
MW	A	B	C	D	E	F~~E~~ =A + B + C + D + E
2025	5.8	(0.1)	(0.1)	0.0	(0.0)	5.6
2030	~~5.8~~5.7	(0.1)	~~(0.2)~~(0.1)	0.~~0~~1	(0.0)	5.~~6~~5
2040	6.1	(0.2)	(0.2)	0.2	(0.0)	5.9
2045	6.3	(0.3)	(0.2)	0.5	(0.0)	6.3
2050	6.5	(0.3)	(0.2)	0.8	(0.0)	6.7

Table 4-~~24~~25: Lānaʻi Peak Forecast (MW)

Year	Underlying	Distributed Energy Resources (PV and BESS)	Energy Efficiency	Electric Vehicles	TOU	Peak Forecast
MW	A	B	C	D	E	F~~E~~ =A + B + C + D + E
2025	6.5	(~~–~~0.0)	(0.1)	~~–~~0.0	(0.0)	6.~~4~~3
2030	6.8	(0.1)	(0.2)	~~——~~0.0	(0.0)	6.~~6~~5
2040	7.2	(0.1)	(0.3)	-0.1	(0.0)	6.9
2045	7.3	(0.2)	(0.4)	0.3	(0.0)	7.0
2050	7.5	(0.2)	(0.4)	0.4	(0.0)	7.3

Similar to the customer level sales forecast, the peak forecast sensitivities were compiled by incorporating varying combinations of the underlying, distributed energy resources, energy efficiency, and electric vehicles hourly forecasts. The following chart includes the Oʻahu peak forecast sensitivities that correspond to the customer sales level forecast sensitivities.

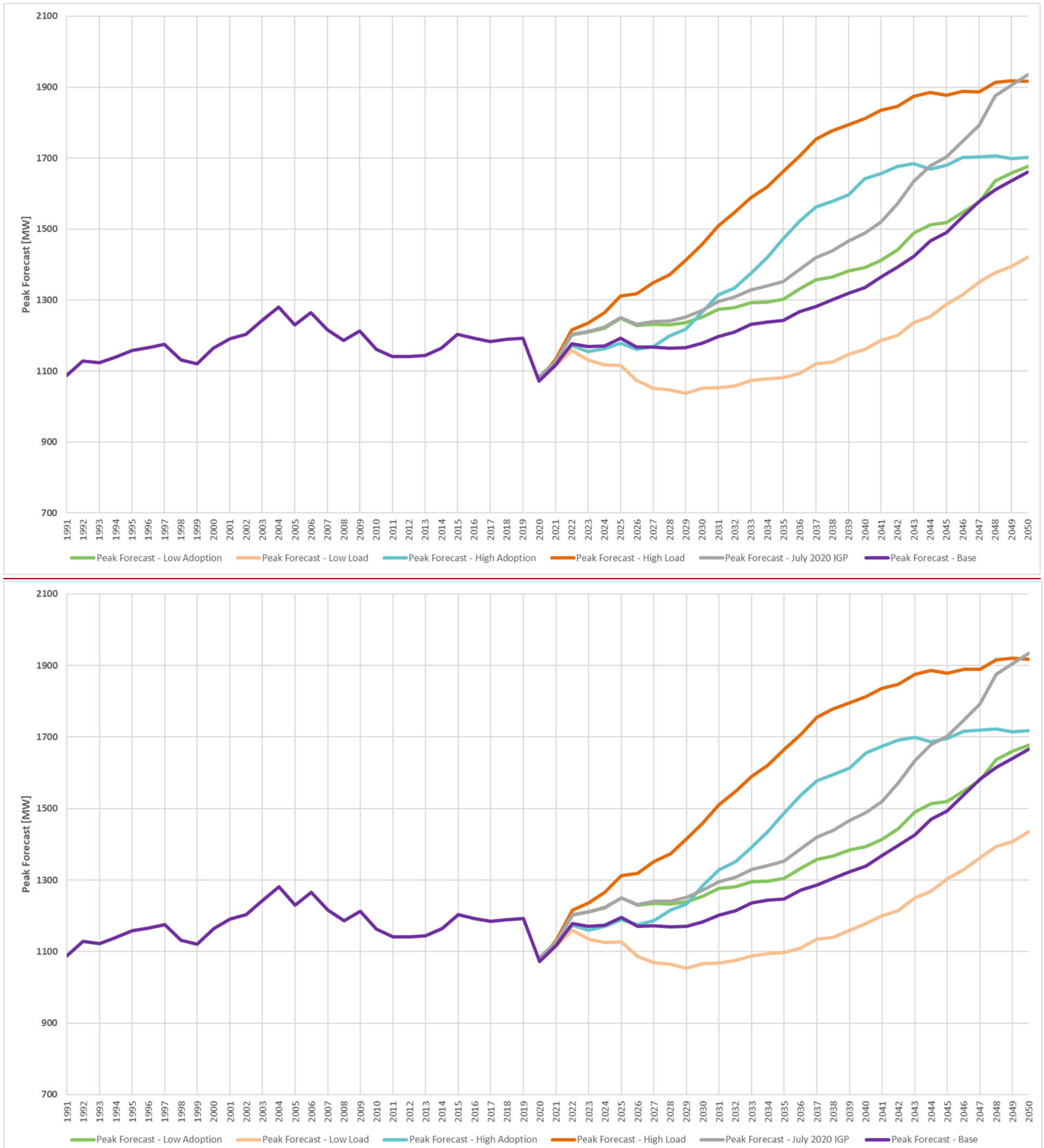


Figure 4-11: O‘ahu Peak Forecast Bookend Sensitivities

4.4 FUEL PRICE FORECASTS

The cost of producing electricity is dependent upon, in part, the cost of fuels utilized to generate power. Hawaiian Electric uses the following fuel types:

- Low Sulfur Fuel Oil (LSFO): A residual fuel oil similar to No. 6 fuel oil that contains less than 5,000 parts per million of sulfur; about 0.5% sulfur content
- No. 2 Diesel Oil
- Ultra-Low Sulfur Diesel (ULSD)
- Naphtha
- High Sulfur Fuel Oil (HSFO): Also called Industrial Fuel Oil (IFO), HSFO contains less than 2% sulfur

The fuel price forecast was developed using a correlation between historical, actual fuel prices and the Brent North Sea Crude Oil Benchmark (Brent) from 1983-2019.[67] The R^2 value for petroleum fuels was greater than 0.93. Hawaiian Electric's 2021 forecast was based on the Brent forecast provided by the Energy Information Administration ("EIA") Annual Energy Outlook ("AEO").

Table 4-~~25~~26: O'ahu Fuel Price Forecast

Year $/MMBTU	LSFO	Diesel	ULSD - CIP	ULSD - SGS	Biodiesel
	8.73	11.49	11.93	12.72	28.55
2022	9.43	12.24	12.71	13.51	29.32
	10.51	13.38	13.87	14.68	30.39
2024	11.36	14.28	14.80	15.62	31.37
	12.14	15.14	15.68	16.52	32.41
2026	13.03	16.11	16.68	17.54	33.60
	13.82	16.99	17.58	18.46	34.78
2028	14.67	17.94	18.56	19.46	36.04
	15.49	18.85	19.50	20.42	37.30
2030	16.36	19.82	20.49	21.45	38.60
	17.14	20.69	21.38	22.36	39.82
2032	18.03	21.67	22.40	23.40	41.12
	18.74	22.47	23.22	24.25	42.29
2034	19.47	23.29	24.07	25.11	43.45

[67] Hawaiian Electric updated its assumptions to use the fuel price forecast provided by the EIA AEO instead of FGE in response to stakeholder feedback to use publicly available, non-proprietary sources.

2035	20.10	24.02	24.81	25.88	44.56
2036	20.90	24.90	25.72	26.82	45.77
2037	21.76	25.86	26.70	27.82	47.03
2038	22.63	26.82	27.69	28.83	48.31
2039	23.18	27.46	28.35	29.52	49.37
2040	24.37	28.76	29.69	30.88	50.91
2041	25.34	29.83	30.79	32.00	52.32
2042	26.15	30.75	31.74	32.98	53.65
2043	27.22	31.93	32.95	34.22	55.21
2044	28.16	32.99	34.04	35.34	56.73
2045	28.65	33.59	34.66	36.00	57.99
2046	29.99	35.08	36.19	37.56	59.92
2047	31.08	36.31	37.46	38.86	61.72
2048	32.03	37.40	38.59	40.03	63.49
2049	33.05	38.57	39.79	41.28	65.38
2050	34.10	39.79	41.05	42.57	67.35

Table 4-~~26~~27: Hawai'i Island Fuel Price Forecast

Year $/MMBTU	IFO	Diesel	ULSD	Naphtha	Biodiesel
2021	7.45	12.16	12.68	13.71	28.55
2022	8.06	12.98	13.52	14.50	29.32
2023	8.99	14.21	14.78	15.69	30.39
2024	9.72	15.18	15.78	16.65	31.37
2025	10.40	16.10	16.73	17.56	32.41
2026	11.17	17.15	17.81	18.61	33.60
2027	11.85	18.09	18.77	19.56	34.78
2028	12.59	19.11	19.82	20.58	36.04
2029	13.29	20.09	20.83	21.58	37.30
2030	14.05	21.13	21.91	22.63	38.60

2031	14.71	22.06	22.87	23.57	39.82
2032	15.48	23.13	23.96	24.64	41.12
2033	16.10	23.99	24.85	25.52	42.29
2034	16.72	24.86	25.75	26.41	43.45
2035	17.27	25.64	26.55	27.21	44.56
2036	17.96	26.59	27.53	28.17	45.77
2037	18.70	27.62	28.59	29.20	47.03
2038	19.45	28.65	29.65	30.24	48.31
2039	19.93	29.34	30.36	30.96	49.37
2040	20.96	30.74	31.80	32.35	50.91
2041	21.79	31.88	32.98	33.50	52.32
2042	22.50	32.87	34.00	34.51	53.65
2043	23.42	34.14	35.31	35.78	55.21
2044	24.23	35.28	36.48	36.94	56.73
2045	24.65	35.92	37.15	37.64	57.99
2046	25.81	37.52	38.79	39.24	59.92
2047	26.75	38.84	40.15	40.59	61.72
2048	27.57	40.01	41.37	41.81	63.49
2049	28.44	41.27	42.66	43.11	65.38
2050	29.35	42.57	44.01	44.46	67.35

Table 4-~~27~~28: Maui County Fuel Price Forecast

Year	Maui				Molokaʻi	Lānaʻi
$/MMBTU	IFO	Diesel	ULSD	Biodiesel	ULSD	ULSD
2021	7.09	11.75	12.09	28.55	12.91	16.08
2022	7.69	12.58	12.94	29.32	13.76	16.95
2023	8.62	13.85	14.23	30.39	15.04	18.26
2024	9.33	14.85	15.26	31.37	16.07	19.33
2025	10.00	15.78	16.22	32.41	17.03	20.35
2026	10.75	16.85	17.31	33.60	18.13	21.51
2027	11.42	17.80	18.28	34.78	19.12	22.58

2028	12.14	18.83	19.34	36.04	20.19	23.73
2029	12.83	19.82	20.36	37.30	21.22	24.84
2030	13.57	20.88	21.44	38.60	22.31	26.02
2031	14.22	21.82	22.40	39.82	23.29	27.08
2032	14.97	22.89	23.50	41.12	24.40	28.28
2033	15.57	23.76	24.39	42.29	25.31	29.27
2034	16.19	24.65	25.30	43.45	26.23	30.27
2035	16.72	25.43	26.10	44.56	27.05	31.17
2036	17.39	26.39	27.09	45.77	28.05	32.26
2037	18.12	27.43	28.15	47.03	29.12	33.41
2038	18.85	28.48	29.22	48.31	30.21	34.58
2039	19.31	29.16	29.93	49.37	30.93	35.39
2040	20.33	30.59	31.39	50.91	32.40	36.94
2041	21.14	31.75	32.58	52.32	33.60	38.23
2042	21.83	32.75	33.60	53.65	34.64	39.36
2043	22.73	34.03	34.92	55.21	35.97	40.79
2044	23.52	35.18	36.09	56.73	37.16	42.09
2045	23.93	35.81	36.74	57.99	37.84	42.90
2046	25.07	37.43	38.40	59.92	39.52	44.70
2047	25.98	38.76	39.76	61.72	40.90	46.22
2048	26.78	39.93	40.97	63.49	42.14	47.60
2049	27.63	41.19	42.26	65.38	43.46	49.07
2050	28.51	42.49	43.60	67.35	44.83	50.60

4.5 RESOURCE COST FORECASTS

Resource cost assumptions were based on publicly available datasets, as shown in Table 4-~~Table 4-28~~.

Table 4-~~28~~29: Resource Cost Data Sources

U.S. Department of Energy (DOE)	• Distributed wind[68],[69] • Pumped Storage Hydro[70]
National Renewable Energy Laboratory (NREL) [71]	• Grid-Scale PV • Distributed PV • Onshore Wind • Geothermal • Biomass • Grid-Scale Storage • Distributed Storage • Combustion Turbine • Combined Cycle • Synchronous Condenser • Offshore wind[72]
US Energy Information Administration (EIA) [73]	• Waste-to-energy
Hawaiian Electric[74]	• ICE

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

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

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

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

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

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

[74] ICE costs are based on the Schofield Generating Station provided in Docket No. 2017-0213, in response to the Consumer Advocate's information request number 19.

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

1. Future technology trends through the planning period;
2. Location-specific capital and O&M cost adjustments for Hawai'i; and
3. Applicable Federal & State tax incentives;
4. Price parity to recent renewable projects.

Figure 4-12~~Figure 4-12~~ is a summary of the resource forecasts in nominal dollars. The resource cost forecasts from 2020-2050 can be found in Appendix A: Nominal Resource Cost Forecasts (2020 – 2050)~~Nominal Resource Cost Forecasts (2020 – 2050)~~. In the near-term, there are price declines after accounting for the investment tax credit schedules for the Federal and State investment tax credits. Over the longer term, after the tax credit schedules ramp down and are held constant, the resources costs generally increase over time. As noted in the NREL ATB, all technologies include electrical infrastructure and interconnection costs for internal and control connections, onsite electrical equipment e.g. switchyard, power electronics and transmission substation upgrades. [75] Similarly, all technologies also include site costs for access roads, buildings for operation and maintenance, fencing, land acquisition, and site preparation in the capital expenditures as well as land lease payments in the fixed costs for O&M.[76] Although the ATB does not discretely break out the percentage of the capital costs or O&M costs associated with either of these items, their inclusion is consistent with the adjustment made for recent PV, wind, geothermal, and PV+BESS projects as actual project pricing would have accounted for interconnection and land costs.

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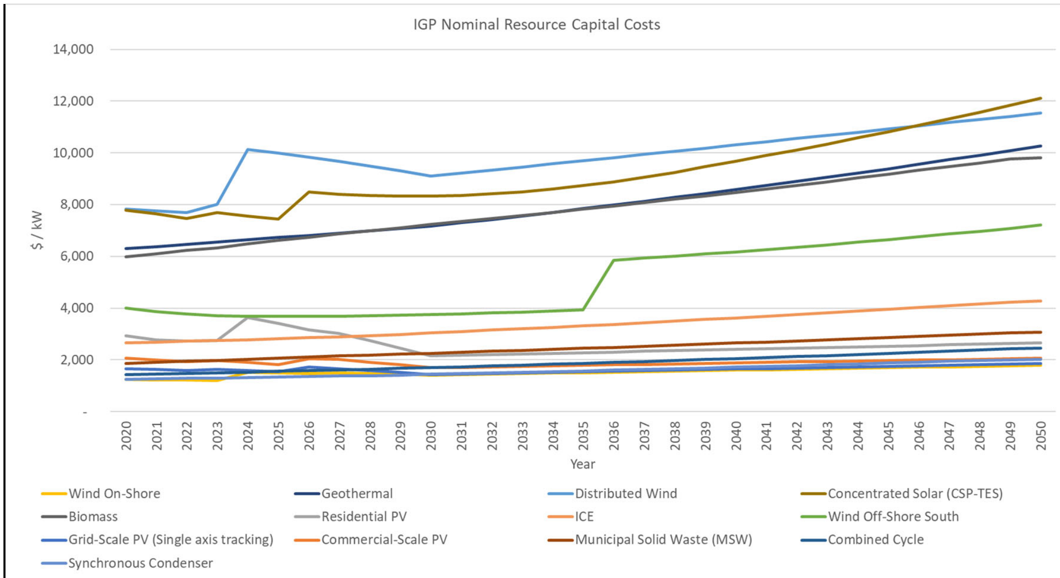
[75] See https://atb.nrel.gov/electricity/2021/definitions#capitalexpenditures

[76] Ibid.



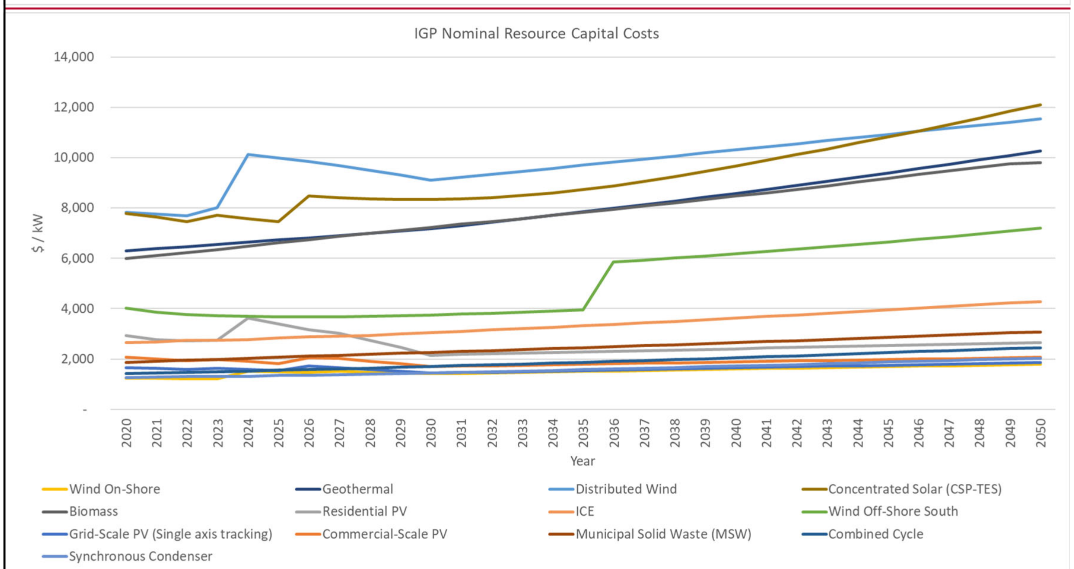
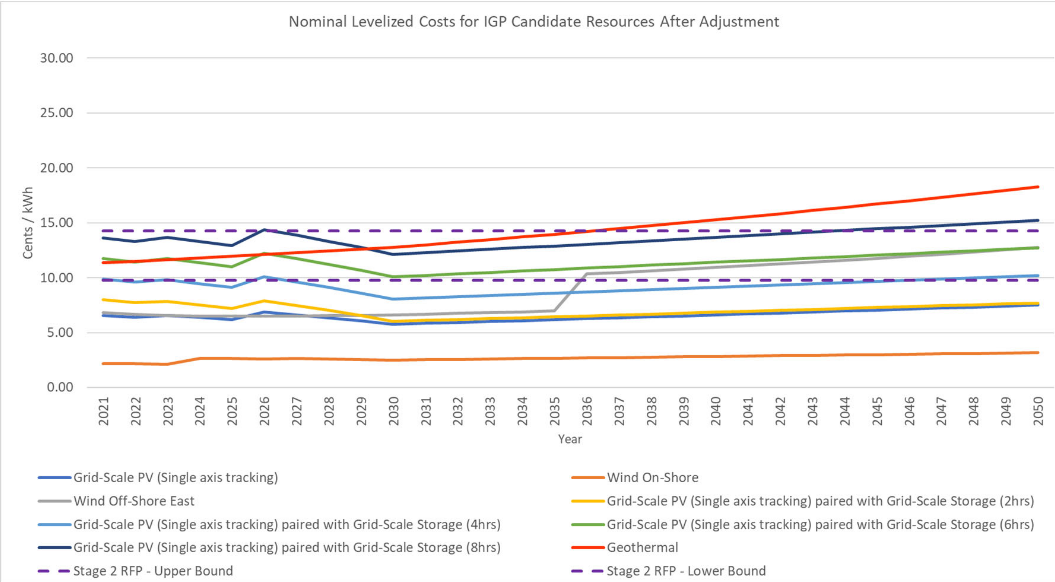


Figure 4-12: Capital Costs for IGP Candidate Resources

A comparison of the levelized cost of energy for select resources to the recently procured solar paired with storage PPAs[77] is shown below in Figure 4-13~~Figure 4-13~~.

[77] *See* https://www.hawaiianelectric.com/new-renewable-projects-submitted-to-regulators-will-produce-lower-cost-electricity-advance-clean-energy



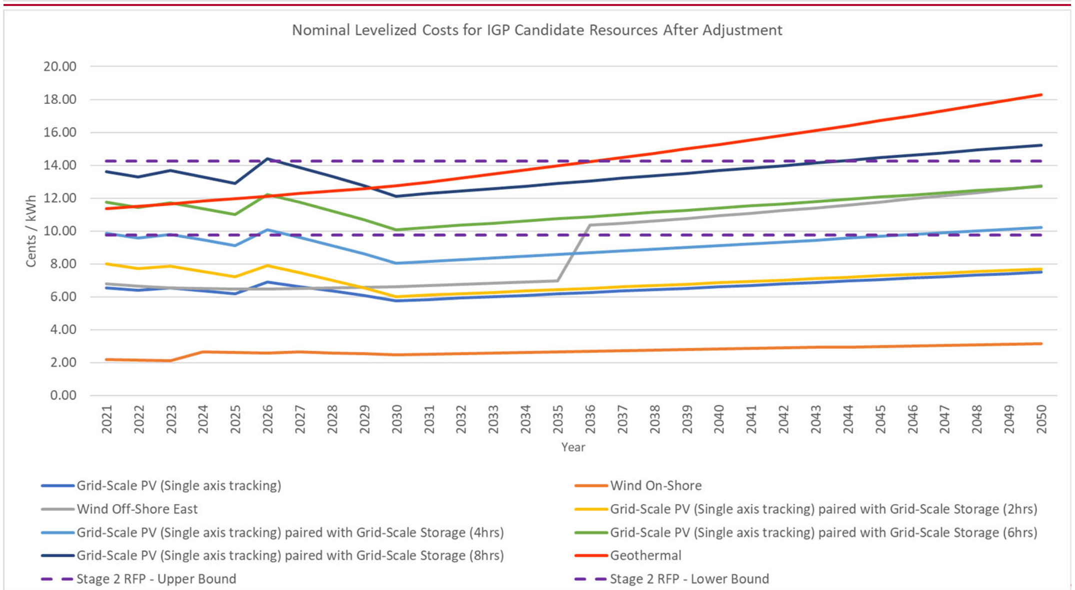


Figure 4-13: Levelized Cost of Energy for Select IGP Candidate Resources

Photovoltaics (PV)

For Photovoltaics (PV), three different classes were forecasted: Grid-Scale PV, Commercial PV, and Residential PV. Each class used a similar process to develop the cost forecast.

Data Source

The source data for capital and fixed operations and maintenance (O&M) costs was provided by the 2021 NREL ATB. For Grid-Scale PV, the capital costs provided were in Real 2019 dollars $/kW$_{ac}$ and the O&M costs provided were in Real 2019 dollars $/kW$_{ac}$-year. For Commercial and Residential PV, the capital costs provided were in Real 2019 dollars $/kW$_{dc}$ and the O&M costs provided were in Real 2019 dollars $/kW$_{dc}$-year. The future trend for the capital and fixed O&M cost was derived from the 2021 NREL ATB projections. The Real 2019 dollars were converted to nominal dollars by applying an escalation factor of 2.3%.

Location Adjustment

A location adjustment factor was applied to convert both capital costs ($/kW) and O&M costs ($/kW-year) to Hawai'i costs. A 63% location adjustment factor for capital[78] was provided by the U.S. Energy Information Administration (EIA)[79] for Grid-Scale PV and a 62% location adjustment factor for Commercial and Residential PV. An 18.5% location adjustment factor for fixed O&M costs was provided by the RSMeans City Cost Index.[80]

DC to AC Conversion

Capital costs for Commercial and Residential PV were converted from $/kW$_{dc}$ to $/kW$_{ac}$. For Commercial and Residential PV, a DC to AC conversion factor of 1.15 was used. These conversion factors were based on assumptions provided by NREL.

Investment Tax Credit Adjustment

The Federal[81] and State ITC[82] schedules assumed for PV are summarized in Table 4-~~Table 4-29~~ below. In December 2020, the Federal ITC for PV was given a two-year extension.[83] The State ITC for grid-scale PV was also removed in 2020.[84] As a result, the capital cost for Grid-Scale PV, Commercial PV, and Residential PV were adjusted accordingly.

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[78] A location cost variation percentage from the EIA Capital Cost Estimates for Utility Scale Electricity Generating Plants.

[79] *See* https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capcost_assumption.pdf

[80] RSMeans Building Construction Cost Data (BCCD) is a reference book for estimating construction costs in the U.S. and Canada.

[81] *See* https://www.greentechmedia.com/articles/read/solar-and-wind-tax-credit-extensions-energy-rd-package-in-spending-bill-before-congress

[82] See https://tax.hawaii.gov/geninfo/renewable

[83] *See* https://www.greentechmedia.com/articles/read/solar-and-wind-tax-credit-extensions-energy-rd-package-in-spending-bill-before-congress

[84] See https://www.capitol.hawaii.gov/hrscurrent/Vol04_Ch0201-0257/HRS0235/HRS_0235-0012_0005.htm

Table 4-~~29~~30: Federal and State ITC Schedule for PV

Year	2020	2021	2022	2023	2024	2025	2026	2027	Future
Federal ITC for Grid-Scale and Commercial-Scale PV	26%	26%	26%	22%	~~10~~22%	~~10~~22%	10%	10%	10%
Federal ITC for Residential PV	26%	26%	26%	22%	0%	0%	0%	0%	0%
State ITC for ~~Grid-Scale,~~ Commercial and Residential PV	35%	35%	25%	25%	20%	20%	20%	15%	15%

Photovoltaics Paired with Battery Energy Storage (PV+BESS)

Data Source

The source data for capital and fixed operations and maintenance (O&M) costs was provided by the 2021 NREL ATB. The capital costs provided were in Real 2019 dollars $/kW$_{ac}$ and the O&M costs provided were in Real 2019 dollars $/kW$_{ac}$-year. The capital costs were provided for both the PV portion and the BESS portion. The BESS capital cost assumed a 4-hour duration and was scaled linearly to estimate the cost for 2-hour, 6-hour, and 8-hour durations. The future trend for the capital and fixed O&M cost was derived from the 2021 NREL ATB projections. The Real 2019 dollars were converted to nominal dollars by applying an escalation factor of 2.3%.

Location Adjustment

A location adjustment factor was applied to convert both capital costs ($/kW) and O&M costs ($/kW-year) to Hawai'i costs. A 63% location adjustment factor for capital[85] was provided by the U.S. Energy Information Administration (EIA)[86] for Grid-Scale PV. An 18.5% location adjustment factor for fixed O&M costs was provided by the RSMeans City Cost Index.[87]

Investment Tax Credit Adjustment

The Federal[88] and State ITC[89] schedules assumed for PV are summarized in Table 4-~~Table 4-29~~ below. In December 2020, the Federal ITC for PV was given

[85] A location cost variation percentage from the EIA Capital Cost Estimates for Utility Scale Electricity Generating Plants.

[86] *See* https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capcost_assumption.pdf

[87] RSMeans Building Construction Cost Data (BCCD) is a reference book for estimating construction costs in the U.S. and Canada.

[88] *See* https://www.greentechmedia.com/articles/read/solar-and-wind-tax-credit-extensions-energy-rd-package-in-spending-bill-before-congress

[89] See https://tax.hawaii.gov/geninfo/renewable

a two-year extension.[90] The State ITC for grid-scale PV was also removed in 2020.[91] These ITC schedules were applied to the PV+BESS system.

Table 4-~~29~~31: Federal and State ITC Schedule for PV

Year	2020	2021	2022	2023	2024	2025	2026	2027	Future
Federal ITC for Grid-Scale and Commercial-Scale PV	26%	26%	26%	22%	22%	22%	10%	10%	10%

~~***Recent Project Adjustment***~~

~~Final capital costs were adjusted based on actual costs from recent projects. For standalone PV, the cost was adjusted by approximately 162% so that the LCOE was similar to West Loch PV (7.5 cents/kWh). For paired PV, the costs were adjusted by approximately 106% so that the annual payment of the paired system would be similar to the lump sum payments of the Stage 2 projects that had a term of 25 years and a 4-hour Battery.~~

Onshore Wind

Data Source

The source data for capital and fixed O&M costs for Onshore Wind was provided by the 2021 NREL ATB. The capital costs were in Real 2019 dollars $/kW. The fixed O&M costs were in Real 2019 $/kW-year. The future trend for the capital and O&M costs was derived from the 2021 NREL ATB projections. The Real 2019 dollars were converted to nominal dollars by applying an escalation factor of 2.3%.

Location Adjustment

The capital costs were converted to Hawai'i costs using a 35% factor from EIA for wind technology. The O&M costs were converted to Hawai'i costs using an 18.5% RSMeans factor. Location-specific interconnection costs were not included in the estimate.

Investment Tax Credit Adjustment

[90] *See* https://www.greentechmedia.com/articles/read/solar-and-wind-tax-credit-extensions-energy-rd-package-in-spending-bill-before-congress

[91] See https://www.capitol.hawaii.gov/hrscurrent/Vol04_Ch0201-0257/HRS0235/HRS_0235-0012_0005.htm

The Federal[92,93] and State ITC[94] schedules assumed for Onshore Wind are summarized in Table 4-~~Table 4-30~~ below. Initially, the Federal ITC for Onshore Wind was to expire at the end of 2020.[95] In December 2020, however, the expiration date was extended a year.[96] As a result, the capital cost was for Onshore Wind was adjusted accordingly.

Table 4-~~30~~32: Federal and State ITC Schedule for Onshore Wind

Year	2020	2021	2022	2023	2024	2025	2026	2027	Future
Federal ITC	18%	18%	0%	0%	0%	0%	0%	0%	0%
State ITC	20%	20%	20%	20%	20%	20%	20%	15%	15%

~~**Recent Project Adjustment**~~

~~Final capital costs were adjusted based on actual costs from recent projects. For Onshore Wind, the costs were adjusted by approximately 772% so that the LCOE was similar to Na Pua Makani (15.3 cents/kWh).~~

Offshore Wind

Data Source

The source data for the Offshore wind estimate was developed specifically for Hawaii by NREL. The NREL study was used to determine the underlying costs for both capital and O&M and was finalized on October 15, 2021.[97]~~.~~

Location Adjustment

The capital costs were converted to Hawai'i costs using a 35% factor from EIA for wind technology. The O&M costs were converted to Hawai'i costs using an 18.5% RSMeans factor. Location-specific interconnection costs were not included in the estimate.

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92 https://www.energy.gov/sites/prod/files/2020/02/f71/weto-funding-factsheet-2020.pdf and https://www.greentechmedia.com/articles/read/solar-and-wind-tax-credit-extensions-energy-rd-package-in-spending-bill-before-congress

93 https://www.greentechmedia.com/articles/read/solar-and-wind-tax-credit-extensions-energy-rd-package-in-spending-bill-before-congress

94 https://tax.hawaii.gov/geninfo/renewable

95 https://www.energy.gov/sites/prod/files/2020/02/f71/weto-funding-factsheet-2020.pdf and https://www.greentechmedia.com/articles/read/solar-and-wind-tax-credit-extensions-energy-rd-package-in-spending-bill-before-congress

96 https://www.greentechmedia.com/articles/read/solar-and-wind-tax-credit-extensions-energy-rd-package-in-spending-bill-before-congress

97 https://www.boem.gov/sites/default/files/documents/regions/pacific-ocs-region/environmental-science/BOEM-2021-070.pdf

~~The capital costs and O&M cost provided by NREL were specifically tailored for Hawaii. Therefore, no location adjustment was needed. The location-specific onshore interconnection costs were not included in the estimate.~~

Investment Tax Credit Adjustment
The Federal[98] and State ITC[99] schedules assumed for Offshore Wind are summarized in Table 4-~~Table 4-31~~ below. Initially, Offshore Wind followed the same schedule as Onshore Wind. In December 2020, the Federal ITC for Offshore Wind was developed.[100] As a result, the capital cost for Offshore Wind was adjusted accordingly.

Table 4-~~31~~33: Federal and State ITC Schedule for Offshore Wind

Year	2020	2021	2022	2023	2024	2025	2026	2027-2035	Future
Federal ITC	30%	30%	30%	30%	30%	30%	30%	30%	0%
State ITC	20%	20%	20%	20%	20%	20%	20%	15%	15%

Distributed Wind

Data Source
The capital and fixed O&M source data for distributed wind was provided by the Department of Energy's Distributed Wind Market Reports. The capital cost was provided in the Department of Energy's 2017 Distributed Wind Market Report.[101] Initially, capital costs in the report were interpreted to be in 2017 dollars. Upon further review, the costs provided in the report were stated in 2016 dollars. Resource costs for distributed wind stated in this document were then adjusted accordingly. The O&M cost were provided in the Department of Energy's 2018 Distributed Wind Market Report. Initially, O&M cost in the report were from the Department of Energy's 2017 Wind Technologies Market Report, but were updated based on the 2018 Distributed Wind Market Report. The average installed small wind costs were used from these reports. These costs were converted to 2019 dollars using a fixed escalation rate of 2.3%. The future

98 https://www.greentechmedia.com/articles/read/solar-and-wind-tax-credit-extensions-energy-rd-package-in-spending-bill-before-congress

99 https://tax.hawaii.gov/geninfo/renewable

100 https://www.greentechmedia.com/articles/read/solar-and-wind-tax-credit-extensions-energy-rd-package-in-spending-bill-before-congress

101 As stated in the 2018 report, because of the extremely low number of small wind project records with installed cost data, a 2018 average cost analysis was not presented in the 2018 report.

cost trend was estimated using the future cost projections from the 2021 NREL ATB for land-based wind.

Location Adjustment
The U.S. benchmark cost was converted to Hawai'i costs for capital and O&M cost estimates. A 35% EIA factor for wind technology was applied for the capital cost conversion to Hawai'i. An 18.5% RSMeans factor was used to convert fixed O&M costs to Hawai'i costs. Location-specific interconnection costs were not included in the estimate.

Investment Tax Credit Adjustment
The Federal[102,103] and State ITC[104] schedules assumed for Distributed Wind are summarized in Table 4-~~Table 4-32~~ below. In December 2020, the Federal ITC was given a two-year extension.[105]

Table 4-~~32~~34: Federal and State ITC for Distributed Wind

Year	2020	2021	2022	2023	2024	2025	2026	2027	Future
Federal ITC	26%	26%	26%	22%	0%	0%	0%	0%	0%
State ITC	20%	20%	20%	20%	20%	20%	20%	15%	15%

Biomass

Data Source
The source data for Biomass capital, fixed O&M, and variable O&M costs as well as Biomass fuel sources were provided by the 2021 NREL ATB for dedicated biomass technology. The capital costs, O&M costs, and fuel costs were given in Real 2019 dollars. The Real 2019 costs were converted to nominal dollars by applying an escalation factor of 2.3%.

Location Adjustment
Nominal capital, O&M and fuel costs for Biomass were converted to Hawai'i costs. The capital costs were converted using a 46% EIA factor. The O&M and

102 https://www.law.cornell.edu/uscode/text/26/48

103 https://rules.house.gov/sites/democrats.rules.house.gov/files/BILLS-116HR133SA-RCP-116-68.pdf

104 https://tax.hawaii.gov/geninfo/renewable

105 See https://www.greentechmedia.com/articles/read/solar-and-wind-tax-credit-extensions-energy-rd-package-in-spending-bill-before-congress

fuel costs were converted to Hawaii using an 18.5% RSMeans factor. Location-specific interconnection costs were not included in the estimate.

Pumped Storage Hydro

Data Source
The source data for Pumped Storage Hydro capital, fixed O&M, and variable O&M costs were provided by the Department of Energy and the Pacific Northwest National Laboratory for a 100 MW, 10 hour duration resource. Capital costs and O&M costs were given in 2020 dollars. Future costs were assumed to increase at an escalation rate of 2.3%.

Location Adjustment
A 45% EIA factor for CT technology was used to convert the capital costs to Hawai'i costs and an 18.5% RSMeans factor was used to convert the fixed O&M and variable O&M costs to Hawai'i costs. Location-specific interconnection costs were not included in the estimate.

Combustion Turbine and Combined Cycle with Synchronous Condenser Function

Data Source
The source data for Combustion Turbine (CT) and Combined Cycle (CC) capital, fixed O&M, and variable O&M costs as well as fuel sources were provided by the 2021 NREL ATB forecast. The capital costs, O&M costs, and fuel costs were given in Real 2019 dollars. The Real 2019 costs were converted to nominal dollars by applying an escalation factor of 2.3%.

Location Adjustment
A 45% EIA factor for CT and CC technology was used to convert the capital costs to Hawai'i costs and an 18.5% RSMeans factor was used to convert the fixed O&M and variable O&M costs to Hawai'i costs. Location-specific interconnection costs were not included in the estimate.

Concentrated Solar Power (CSP)

Data Source
The source data for Concentrated Solar Power (CSP) capital, fixed O&M, and variable O&M costs was provided by the 2021 NREL ATB. Capital costs and O&M costs were given in Real 2019 dollars. The Real 2019 costs were converted to nominal dollars by applying an escalation factor of 2.3%.

Location Adjustment
A 62% EIA factor for PV was used as an approximation to convert capital costs to Hawai'i costs. The federal and state investment tax credit schedule was assumed to be the same as grid scale PV. Fixed and variable O&M costs were converted to Hawai'i costs using an 18.5% RSMeans factor. Location-specific interconnection costs were not included in the estimate.

Investment Tax Credit Adjustment
The Federal[106] and State ITC[107] schedules assumed for CSP are summarized in Table ~~Table~~, below. Initially, there were no Federal or State ITC assumed for CSP. After additional consideration, it was determined that a CSP system should be considered as a system that uses solar energy to generate electricity. As a result, CSP should receive the Federal and State ITC. The latest Federal and State ITC were applied, and the capital cost was adjusted.

Table 4-~~33~~35: Federal and State ITC Schedule for CSP

Year	2020	2021	2022	2023	2024	2025	2026	2027	Future
Federal ITC	26%	26%	26%	22%	10%	10%	10%	10%	10%
State ITC	35%	35%	25%	25%	20%	20%	20%	15%	15%

Geothermal

Data Source
The source data for the Geothermal capital, fixed and variable O&M were provided by the 2021 NREL ATB for Geothermal geo-hydro binary technology. The capital costs, O&M costs and fuel costs in ATB were given in Real 2019 dollars and converted to nominal dollars by applying an escalation factor of 2.3%.

Location Adjustment
A 20% EIA factor for Geothermal technology was used to convert capital costs to Hawai'i costs. Fixed O&M and variable O&M costs used an 18.5% RSMeans factor. Location-specific interconnection costs were not included in the estimate.

Investment Tax Credit Adjustment

106 https://www.greentechmedia.com/articles/read/solar-and-wind-tax-credit-extensions-energy-rd-package-in-spending-bill-before-congress

107 https://tax.hawaii.gov/geninfo/renewable

The following federal tax credit schedule[108] was assumed for Geothermal technology.

Table 4-~~34~~36: Federal and State ITC for Geothermal

Year	2020	2021	2022	2023	2024	2025	2026	2027	Future
Federal ITC	10%	10%	10%	10%	10%	10%	10%	10%	10%
State ITC	0%	0%	0%	0%	0%	0%	0%	0%	0%

~~**Recent Project Adjustment**~~
~~Final capital costs were adjusted based on actual costs from the current PGV contract and amended contract application provided in Docket No. 2019-0333. For Geothermal, the costs were adjusted by approximately 141% based on an average LCOE of the current (16.4 cents/kWh) and amended contract (11.4 cents/kWh), calculated using the minimum purchase requirement from the amended contract and historical annual payments made to PGV under the current contract.~~

Internal Combustion Engine (ICE)

Data Source
The source data to estimate Internal Combustion Engine (ICE) technology was informed by actual costs for the Schofield Generating Station project constructed on O'ahu. The cost estimates were escalated from 2017 dollars by applying an escalation factor of 2.3%. The future cost trend was estimated using the cost trend for gas CT technology discussed above due to limited information on a future ICE capital cost trend.

Municipal Solid Waste (MSW)

Data Source
The Municipal Solid Waste (MSW) source data was based on the U.S. Energy Information Administration Cost and Performance Characteristics of New Generating Technologies Annual Energy Outlook for 2019. The costs were adjusted from 2018 dollars to 2019 dollars by applying an escalation factor of 2.3%. The future cost projections were estimated using future cost trend from Biomass technology discussed above due to limited information on future MSW capital cost trend.

[108] https://programs.dsireusa.org/system/program/detail/658

Location Adjustment
A 20% EIA factor for Biomass technology was used as an approximation to convert capital costs. Fixed O&M and variable O&M costs were converted to Hawai'i costs using an 18.5% RSMeans factor.

Battery Energy Storage

Data Source
The source data for Grid-Scale and Residential Battery Energy Storage Systems (BESS) was provided in the 2021 NREL ATB. Both the Balance of System cost, provided in $/kW, and the Module costs, provided in $/kWh, were in provided in Real 2019 dollars. Embedded interconnection cost was removed from the estimate. The Real 2019 costs were converted to nominal dollars by applying an escalation factor of 2.3%.

Location Adjustment
The capital costs for Balance of System and Modules were converted to Hawai'i costs using a 32% EIA factor. Fixed O&M and variable O&M costs were converted to Hawai'i costs using an 18.5% RSMeans factor.

~~**Pairing Adjustment**~~
~~Paired storage capital costs were adjusted based on the PV tax credit schedule. Because the State tax credit has a dollar cap, the State tax credit applied to paired storage is the difference between the cap and the amount already applied to the PV system.~~

~~**Recent Project Adjustment**~~
~~Final capital costs were adjusted based on actual costs from recent projects. For standalone BESS, the costs were adjusted by approximately 105% so the annual payment would be similar to the lump sum payments for the Kapolei Energy Storage System. For paired BESS, the costs were given the same adjustment as the paired PV, as described earlier.~~

Synchronous Condenser

Data Source
The cost projections were estimated using Combustion Turbine technology discussed above due to limited information on Synchronous Condenser capital cost in the 2021 NREL ATB. Cost for conversion of existing generators to synchronous condensers will be considered on a case-by-case basis.

Appendix A: Nominal Resource Cost Forecasts (2020 – 2050)

Table A-1: Capital and O&M Costs for Resource Options (Paired Grid-Scale PV, Standalone Grid-Scale PV, Commercial-Scale PV)

Year	Paired Grid-Scale PV (Single axis tracking)		Standalone Grid-Scale PV (Single axis tracking)		Commercial-Scale PV	
	Capital ($/kW)	O&M ($/kW-year)	Capital ($/kW)	O&M ($/kW-year)	Capital ($/kW)	O&M ($/kW-year)
2020	1,585 ~~1,381~~	44 ~~28~~	1,663 ~~2,105~~	28 ~~28~~	2,067 ~~2,067~~	26 ~~26~~
2021	1,526 ~~1,343~~	43 ~~28~~	1,627 ~~2,048~~	28 ~~28~~	2,004 ~~2,004~~	25 ~~25~~
2022	1,463 ~~1,303~~	43 ~~28~~	1,589 ~~1,986~~	28 ~~28~~	1,936 ~~1,936~~	25 ~~25~~
2023	1,473 ~~1,348~~	42 ~~28~~	1,632 ~~2,056~~	28 ~~28~~	1,984 ~~1,984~~	25 ~~25~~
2024	1,399 ~~1,629~~	41 ~~27~~	1,586 ~~2,484~~	27 ~~27~~	1,904 ~~2,252~~	24 ~~24~~
2025	1,321 ~~1,579~~	40 ~~27~~	1,538 ~~2,408~~	27 ~~27~~	1,818 ~~2,153~~	24 ~~24~~
2026	1,429 ~~1,526~~	39 ~~27~~	1,714 ~~2,326~~	27 ~~27~~	2,048 ~~2,048~~	23 ~~23~~
2027	1,329 ~~1,539~~	38 ~~27~~	1,650 ~~2,346~~	27 ~~27~~	2,021 ~~2,021~~	22 ~~22~~
2028	1,223 ~~1,476~~	37 ~~26~~	1,583 ~~2,250~~	26 ~~26~~	1,918 ~~1,918~~	22 ~~22~~
2029	1,112 ~~1,409~~	36 ~~26~~	1,511 ~~2,148~~	26 ~~26~~	1,808 ~~1,808~~	21 ~~21~~
2030	995 ~~1,338~~	35 ~~25~~	1,435 ~~2,040~~	25 ~~25~~	1,692 ~~1,692~~	20 ~~20~~
2031	1,009 ~~1,357~~	35 ~~26~~	1,455 ~~2,069~~	26 ~~26~~	1,712 ~~1,712~~	21 ~~21~~
2032	1,023 ~~1,376~~	36 ~~26~~	1,476 ~~2,098~~	26 ~~26~~	1,731 ~~1,731~~	21 ~~21~~

2033	1,037 ~~1,396~~	36 ~~27~~	1,496 ~~2,128~~	27 ~~27~~	1,750 ~~1,750~~	21 ~~21~~
2034	1,052 ~~1,415~~	37 ~~27~~	1,517 ~~2,157~~	27 ~~27~~	1,769 ~~1,769~~	22 ~~22~~
2035	1,066 ~~1,435~~	37 ~~28~~	1,538 ~~2,187~~	28 ~~28~~	1,789 ~~1,789~~	22 ~~22~~
2036	1,081 ~~1,454~~	38 ~~28~~	1,559 ~~2,217~~	28 ~~28~~	1,808 ~~1,808~~	22 ~~22~~
2037	1,095 ~~1,474~~	38 ~~29~~	1,581 ~~2,247~~	29 ~~29~~	1,827 ~~1,827~~	23 ~~23~~
2038	1,110 ~~1,494~~	39 ~~29~~	1,602 ~~2,278~~	29 29	1,846 ~~1,846~~	23 23
2039	1,125 ~~1,514~~	40 ~~30~~	1,624 ~~2,309~~	30 ~~30~~	1,864 ~~1,864~~	23 ~~23~~
2040	1,140 ~~1,535~~	40 30	1,645 ~~2,339~~	30 ~~30~~	1,883 ~~1,883~~	24 ~~24~~
2041	1,155 ~~1,555~~	41 ~~31~~	1,667 ~~2,370~~	31 ~~31~~	1,902 ~~1,902~~	24 ~~24~~
2042	1,170 ~~1,575~~	42 31	1,689 ~~2,402~~	31 ~~31~~	1,920 ~~1,920~~	24 ~~24~~
2043	1,185 ~~1,596~~	42 ~~32~~	1,711 ~~2,433~~	32 ~~32~~	1,938 ~~1,938~~	25 ~~25~~
2044	1,201 ~~1,617~~	43 ~~33~~	1,733 ~~2,465~~	33 ~~33~~	1,956 ~~1,956~~	25 ~~25~~
2045	1,216 ~~1,637~~	43 ~~33~~	1,756 ~~2,496~~	33 ~~33~~	1,974 ~~1,974~~	26 ~~26~~
2046	1,231 ~~1,658~~	44 ~~34~~	1,778 ~~2,528~~	34 ~~34~~	1,991 ~~1,991~~	26 ~~26~~
2047	1,247 ~~1,679~~	45 ~~34~~	1,801 ~~2,560~~	34 ~~34~~	2,009 ~~2,009~~	26 ~~26~~
2048	1,262 ~~1,700~~	45 ~~35~~	1,823 ~~2,592~~	35 ~~35~~	2,026 ~~2,026~~	27 ~~27~~
2049	1,278 ~~1,721~~	46 ~~36~~	1,846 ~~2,624~~	36 ~~36~~	2,042 ~~2,042~~	27 ~~27~~
2050	1,294 ~~1,743~~	47 ~~36~~	1,869 ~~2,657~~	36 36	2,059 ~~2,059~~	27 ~~27~~

Table A-2: Capital and O&M Costs for Resource Options (Residential PV, Onshore Wind, Distributed Wind)

Year	Residential PV		Onshore Wind		Distributed Wind	
	Capital ($/kW)	O&M ($/kW-year)	Capital ($/kW)	O&M ($/kW-year)	Capital ($/kW)	O&M ($/kW-year)
2020	2,923 ~~2,923~~	40 ~~40~~	1,245 ~~9,618~~	52 ~~52~~	7,834 ~~7,834~~	49 ~~49~~
2021	2,766 ~~2,766~~	39 ~~39~~	1,234 ~~9,530~~	52 ~~52~~	7,761 ~~7,761~~	50 ~~50~~
2022	2,730 ~~2,730~~	38 ~~38~~	1,221 ~~11,944~~	53 ~~53~~	7,682 ~~7,682~~	51 ~~51~~
2023	2,749 ~~2,749~~	36 ~~36~~	1,207 ~~11,807~~	54 ~~54~~	8,005 ~~8,005~~	51 ~~51~~
2024	3,628 ~~3,628~~	35 ~~35~~	1,509 ~~11,658~~	55 ~~55~~	10,136 ~~10,136~~	52 ~~52~~
2025	3,400 ~~3,400~~	33 ~~33~~	1,488 ~~11,496~~	55 ~~55~~	9,995 ~~9,995~~	53 ~~53~~
2026	3,160 ~~3,160~~	31 ~~31~~	1,466 ~~11,320~~	56 ~~56~~	9,841 ~~9,841~~	54 ~~54~~
2027	3,028 ~~3,028~~	30 ~~30~~	1,502 ~~11,597~~	57 ~~57~~	9,676 ~~9,676~~	54 ~~54~~
2028	2,750 ~~2,750~~	28 ~~28~~	1,474 ~~11,383~~	58 ~~58~~	9,497 ~~9,497~~	55 ~~55~~
2029	2,457 ~~2,457~~	26 ~~26~~	1,444 ~~11,152~~	59 ~~59~~	9,304 ~~9,304~~	56 ~~56~~
2030	2,149 ~~2,149~~	24 ~~24~~	1,412 ~~10,905~~	59 ~~59~~	9,097 ~~9,097~~	57 ~~57~~
2031	2,175 ~~2,175~~	24 ~~24~~	1,430 ~~11,047~~	60 ~~60~~	9,216 ~~9,216~~	57 ~~57~~
2032	2,201 ~~2,201~~	24 ~~24~~	1,449 ~~11,190~~	61 ~~61~~	9,335 ~~9,335~~	58 ~~58~~
2033	2,226 ~~2,226~~	25 ~~25~~	1,467 ~~11,334~~	62 ~~62~~	9,455 ~~9,455~~	59 ~~59~~

2034	2,252 ~~2,252~~	25 ~~25~~	1,486 ~~11,478~~	63 ~~63~~	9,576 ~~9,576~~	60 ~~60~~
2035	2,278 ~~2,278~~	25 ~~25~~	1,505 ~~11,623~~	64 ~~64~~	9,697 ~~9,697~~	61 ~~61~~
2036	2,303 ~~2,303~~	26 ~~26~~	1,524 ~~11,768~~	65 ~~65~~	9,818 ~~9,818~~	62 ~~62~~
2037	2,329 ~~2,329~~	26 ~~26~~	1,543 ~~11,914~~	66 ~~66~~	9,940 ~~9,940~~	63 ~~63~~
2038	2,355 ~~2,355~~	27 ~~27~~	1,562 ~~12,061~~	67 ~~67~~	10,063 ~~10,063~~	64 ~~64~~
2039	2,380 ~~2,380~~	27 ~~27~~	1,581 ~~12,207~~	68 ~~68~~	10,185 ~~10,185~~	65 ~~65~~
2040	2,406 ~~2,406~~	27 ~~27~~	1,600 ~~12,354~~	69 ~~69~~	10,308 ~~10,308~~	66 ~~66~~
2041	2,431 ~~2,431~~	28 ~~28~~	1,619 ~~12,501~~	70 ~~70~~	10,431 ~~10,431~~	67 ~~67~~
2042	2,456 ~~2,456~~	28 ~~28~~	1,638 ~~12,649~~	71 ~~71~~	10,554 ~~10,554~~	68 ~~68~~
2043	2,481 ~~2,481~~	29 ~~29~~	1,657 ~~12,796~~	72 ~~72~~	10,677 ~~10,677~~	69 ~~69~~
2044	2,506 ~~2,506~~	29 ~~29~~	1,676 ~~12,943~~	73 ~~73~~	10,800 ~~10,800~~	70 ~~70~~
2045	2,531 ~~2,531~~	30 ~~30~~	1,695 ~~13,091~~	75 ~~75~~	10,923 ~~10,923~~	71 ~~71~~
2046	2,555 ~~2,555~~	30 ~~30~~	1,714 ~~13,238~~	76 ~~76~~	11,046 ~~11,046~~	72 ~~72~~
2047	2,579 ~~2,579~~	30 ~~30~~	1,733 ~~13,385~~	77 ~~77~~	11,169 ~~11,169~~	73 ~~73~~
2048	2,603 ~~2,603~~	31 ~~31~~	1,752 ~~13,532~~	78 ~~78~~	11,291 ~~11,291~~	74 ~~74~~
2049	2,627 ~~2,627~~	31 ~~31~~	1,771 ~~13,678~~	79 ~~79~~	11,413 ~~11,413~~	75 ~~75~~
2050	2,651 ~~2,651~~	32 ~~32~~	1,790 ~~13,823~~	80 ~~80~~	11,535 ~~11,535~~	76 ~~76~~

Table A-3: Capital and O&M Costs for Resource Options (Offshore Wind North, Offshore Wind East, Offshore Wind South)

Year	Offshore Wind North		Offshore Wind East		Offshore Wind South	
	Capital ($/kW)	O&M ($/kW-year)	Capital ($/kW)	O&M ($/kW-year)	Capital ($/kW)	O&M ($/kW-year)
2020	4,551 ~~2,976~~	87 ~~73~~	4,152 ~~2,705~~	87 ~~73~~	4,009 ~~2,607~~	82 ~~69~~
2021	4,387 ~~2,863~~	81 ~~68~~	3,994 ~~2,597~~	81 ~~69~~	3,855 ~~2,501~~	76 ~~65~~
2022	4,295 ~~2,800~~	77 ~~65~~	3,904 ~~2,536~~	78 ~~65~~	3,766 ~~2,441~~	73 ~~62~~
2023	4,242 ~~2,764~~	75 ~~63~~	3,852 ~~2,501~~	75 ~~63~~	3,715 ~~2,406~~	71 ~~60~~
2024	4,215 ~~2,745~~	73 ~~61~~	3,824 ~~2,481~~	73 ~~62~~	3,686 ~~2,386~~	69 ~~58~~
2025	4,205 ~~2,738~~	71 ~~60~~	3,811 ~~2,472~~	71 ~~60~~	3,673 ~~2,377~~	67 ~~57~~
2026	4,208 ~~4,069~~	70 ~~59~~	3,811 ~~3,686~~	70 ~~59~~	3,672 ~~3,549~~	66 ~~56~~
2027	4,222 ~~4,082~~	69 ~~58~~	3,821 ~~3,695~~	69 ~~58~~	3,681 ~~3,557~~	66 ~~55~~
2028	4,243 ~~4,102~~	68 ~~58~~	3,838 ~~3,711~~	69 ~~58~~	3,697 ~~3,572~~	65 ~~55~~
2029	4,272 ~~4,129~~	68 ~~57~~	3,861 ~~3,734~~	68 ~~57~~	3,718 ~~3,593~~	64 ~~54~~
2030	4,306 ~~4,162~~	67 ~~57~~	3,890 ~~3,761~~	68 ~~57~~	3,746 ~~3,619~~	64 ~~54~~
2031	4,345 ~~4,200~~	67 ~~57~~	3,924 ~~3,794~~	67 ~~57~~	3,778 ~~3,649~~	64 ~~54~~
2032	4,389 ~~4,242~~	67 ~~56~~	3,962 ~~3,830~~	67 ~~56~~	3,814 ~~3,684~~	64 ~~54~~
2033	4,437 ~~4,288~~	67 ~~56~~	4,003 ~~3,871~~	67 ~~56~~	3,853 ~~3,722~~	63 ~~54~~
2034	4,489 ~~4,338~~	67 ~~56~~	4,049 ~~3,914~~	67 ~~56~~	3,896 ~~3,764~~	63 ~~53~~

2035	4,544 ~~4,391~~	66 ~~56~~	4,097 ~~3,961~~	67 ~~56~~	3,942 ~~3,808~~	63 ~~53~~
2036	6,730 ~~4,448~~	67 ~~56~~	6,081 ~~4,011~~	67 ~~56~~	5,856 ~~3,856~~	63 ~~54~~
2037	6,818 ~~4,508~~	67 ~~56~~	6,158 ~~4,063~~	67 ~~56~~	5,931 ~~3,906~~	64 ~~54~~
2038	6,911 ~~4,570~~	67 ~~56~~	6,240 ~~4,118~~	67 ~~56~~	6,008 ~~3,958~~	64 ~~54~~
2039	7,007 ~~4,635~~	67 ~~56~~	6,325 ~~4,176~~	67 ~~57~~	6,090 ~~4,014~~	64 ~~54~~
2040	7,108 ~~4,704~~	67 57	6,414 ~~4,236~~	67 57	6,175 ~~4,071~~	64 54
2041	7,213 ~~4,774~~	67 ~~57~~	6,506 ~~4,299~~	67 ~~57~~	6,264 ~~4,131~~	64 ~~54~~
2042	7,321 ~~4,848~~	68 ~~57~~	6,602 ~~4,364~~	68 ~~57~~	6,355 ~~4,193~~	65 ~~55~~
2043	7,434 ~~4,923~~	68 ~~57~~	6,702 ~~4,431~~	68 ~~57~~	6,451 ~~4,257~~	65 ~~55~~
2044	7,550 ~~5,002~~	68 ~~57~~	6,805 ~~4,500~~	68 ~~58~~	6,549 ~~4,324~~	65 ~~55~~
2045	7,669 ~~5,083~~	68 ~~58~~	6,911 ~~4,572~~	69 ~~58~~	6,650 ~~4,393~~	66 ~~55~~
2046	7,793 ~~5,166~~	69 ~~58~~	7,020 ~~4,646~~	69 ~~58~~	6,755 ~~4,463~~	66 ~~56~~
2047	7,920 ~~5,252~~	69 ~~58~~	7,133 ~~4,722~~	69 ~~59~~	6,863 ~~4,537~~	66 ~~56~~
2048	8,051 ~~5,340~~	70 ~~59~~	7,249 ~~4,801~~	70 ~~59~~	6,974 ~~4,612~~	67 ~~56~~
2049	8,185 ~~5,431~~	70 ~~59~~	7,368 ~~4,882~~	70 ~~59~~	7,089 ~~4,689~~	67 ~~57~~
2050	8,323 ~~5,525~~	71 ~~60~~	7,491 ~~4,965~~	71 ~~60~~	7,206 ~~4,769~~	68 ~~57~~

Table A-4: Capital and O&M Costs for Resource Options (Grid-Scale Storage, Pumped Storage Hydro)

Year	Grid-Scale Storage			Pumped Storage Hydro		
	Balance of System ($/kW)	Modules ($/kWh)	O&M ($/kW-year)	Capital ($/kW)	O&M ($/kW-year)	Var O&M ($/MWH)
2020	347 ~~365~~	374 ~~393~~	41 ~~41~~	2,852 ~~2,852~~	36 ~~36~~	1 ~~1~~
2021	339 ~~356~~	358 ~~377~~	40 ~~40~~	2,919 ~~2,919~~	37 ~~37~~	1 ~~1~~
2022	330 347	342 360	38 38	2,987 ~~2,987~~	38 38	1 1
2023	320 ~~337~~	325 ~~342~~	36 ~~36~~	3,056 ~~3,056~~	39 ~~39~~	1 ~~1~~
2024	310 ~~327~~	307 ~~322~~	34 ~~34~~	3,127 ~~3,127~~	39 ~~39~~	1 ~~1~~
2025	300 ~~315~~	287 ~~302~~	33 ~~33~~	3,200 ~~3,200~~	40 ~~40~~	1 ~~1~~
2026	306 ~~322~~	281 ~~295~~	32 ~~32~~	3,274 ~~3,274~~	41 ~~41~~	1 ~~1~~
2027	313 ~~330~~	274 ~~288~~	32 ~~32~~	3,351 ~~3,351~~	42 ~~42~~	1 ~~1~~
2028	320 ~~337~~	266 ~~280~~	31 ~~31~~	3,429 ~~3,429~~	43 ~~43~~	1 ~~1~~
2029	327 ~~345~~	258 ~~272~~	31 ~~31~~	3,509 ~~3,509~~	44 ~~44~~	1 ~~1~~
2030	335 ~~352~~	250 ~~263~~	30 ~~30~~	3,590 ~~3,590~~	45 ~~45~~	1 ~~1~~
2031	341 ~~359~~	251 ~~265~~	30 ~~30~~	3,674 ~~3,674~~	46 ~~46~~	1 ~~1~~
2032	348 ~~366~~	253 ~~267~~	31 ~~31~~	3,759 ~~3,759~~	47 ~~47~~	1 ~~1~~
2033	355 ~~373~~	255 ~~268~~	31 ~~31~~	3,847 ~~3,847~~	49 ~~49~~	1 ~~1~~

2034	361 ~~380~~	257 ~~270~~	31 ~~31~~	3,936 ~~3,936~~	50 ~~50~~	1 ~~1~~
2035	368 ~~388~~	258 ~~272~~	31 ~~31~~	4,028 ~~4,028~~	51 ~~51~~	1 ~~1~~
2036	375 ~~395~~	260 ~~274~~	32 ~~32~~	4,122 ~~4,122~~	52 ~~52~~	1 ~~1~~
2037	383 ~~403~~	262 ~~275~~	32 ~~32~~	4,218 ~~4,218~~	53 ~~53~~	1 ~~1~~
2038	390 ~~410~~	263 ~~277~~	32 ~~32~~	4,316 ~~4,316~~	55 ~~55~~	1 ~~1~~
2039	397 ~~418~~	265 ~~278~~	33 ~~33~~	4,417 ~~4,417~~	56 ~~56~~	1 ~~1~~
2040	405 ~~426~~	266 ~~280~~	33 ~~33~~	4,519 ~~4,519~~	57 ~~57~~	1 ~~1~~
2041	413 ~~434~~	267 ~~281~~	33 ~~33~~	4,625 ~~4,625~~	58 ~~58~~	1 ~~1~~
2042	421 ~~443~~	268 ~~282~~	34 ~~34~~	4,732 ~~4,732~~	60 ~~60~~	1 ~~1~~
2043	429 ~~451~~	269 ~~283~~	34 ~~34~~	4,842 ~~4,842~~	61 ~~61~~	1 ~~1~~
2044	437 ~~460~~	270 ~~284~~	34 ~~34~~	4,955 ~~4,955~~	63 ~~63~~	1 ~~1~~
2045	445 ~~468~~	271 ~~285~~	34 ~~34~~	5,071 ~~5,071~~	64 ~~64~~	1 ~~1~~
2046	454 ~~477~~	272 ~~286~~	35 ~~35~~	5,189 ~~5,189~~	66 ~~66~~	1 ~~1~~
2047	462 ~~486~~	273 ~~287~~	35 ~~35~~	5,309 ~~5,309~~	67 ~~67~~	1 ~~1~~
2048	471 ~~495~~	273 ~~287~~	35 ~~35~~	5,433 ~~5,433~~	69 ~~69~~	1 ~~1~~
2049	480 ~~505~~	274 ~~288~~	35 ~~35~~	5,559 ~~5,559~~	70 ~~70~~	1 ~~1~~
2050	489 514	274 288	36 36	5,689 ~~5,689~~	72 ~~72~~	1 ~~1~~

Table A-5: Capital and O&M Costs for Resource Options (Paired Grid-Scale Storage (2hrs), Paired Grid-Scale Storage (4hrs))

Year	Paired Grid-Scale Storage (2hr)		Paired Grid-Scale Storage (4hr)	
	Capital ($/kW)	O&M ($/kW-year)	Capital ($/kW)	O&M ($/kW-year)
2020	344 ~~858~~	– ~~41~~	689 ~~1,444~~	– ~~41~~
2021	342 ~~827~~	– ~~40~~	684 ~~1,389~~	– ~~40~~
2022	339 ~~795~~	– ~~38~~	679 ~~1,331~~	– ~~38~~
2023	355 ~~802~~	– ~~36~~	709 ~~1,339~~	– ~~36~~
2024	351 ~~810~~	– ~~34~~	702 ~~1,394~~	– ~~34~~
2025	347 ~~753~~	– ~~33~~	694 ~~1,301~~	– ~~33~~
2026	396 ~~737~~	– ~~32~~	791 ~~1,272~~	– ~~32~~
2027	390 ~~722~~	– ~~32~~	781 ~~1,182~~	– ~~32~~
2028	385 ~~716~~	– ~~31~~	769 ~~1,162~~	– ~~31~~
2029	378 ~~708~~	– ~~31~~	757 ~~1,141~~	– ~~31~~
2030	372 ~~700~~	– ~~30~~	743 ~~1,119~~	– ~~30~~
2031	376 ~~709~~	– ~~30~~	752 ~~1,131~~	– ~~30~~
2032	380 ~~717~~	– ~~31~~	761 ~~1,142~~	– ~~31~~
2033	385 ~~726~~	– ~~31~~	770 ~~1,154~~	– ~~31~~
2034	389 ~~734~~	– ~~31~~	779 ~~1,166~~	– ~~31~~
2035	394 ~~743~~	– ~~31~~	788 ~~1,177~~	– ~~31~~
2036	398 ~~752~~	– ~~32~~	796 ~~1,188~~	– ~~32~~
2037	403 ~~760~~	– ~~32~~	805 ~~1,200~~	– ~~32~~
2038	407 ~~769~~	– ~~32~~	814 ~~1,211~~	– ~~32~~
2039	412 ~~778~~	– ~~33~~	823 ~~1,222~~	– ~~33~~
2040	416 ~~786~~	– ~~33~~	832 ~~1,232~~	– ~~33~~
2041	420 ~~795~~	– ~~33~~	841 ~~1,243~~	– ~~33~~
2042	425 ~~803~~	– ~~34~~	849 ~~1,258~~	– ~~34~~
2043	429 ~~812~~	– ~~34~~	858 ~~1,272~~	– ~~34~~
2044	433 ~~820~~	– ~~34~~	867 ~~1,287~~	– ~~34~~
2045	438 ~~829~~	– ~~34~~	875 ~~1,301~~	– ~~34~~
2046	442 ~~837~~	– ~~35~~	884 ~~1,315~~	– ~~35~~

2047	446 ~~846~~	- ~~35~~	892 ~~1,328~~	- ~~35~~
2048	450 ~~854~~	- ~~35~~	900 ~~1,342~~	- ~~35~~
2049	454 ~~862~~	- ~~35~~	909 ~~1,355~~	- ~~35~~
2050	458 ~~870~~	- ~~36~~	917 ~~1,367~~	- ~~36~~

Table A-6: Capital and O&M Costs for Resource Options (Paired Grid-Scale Storage (6hrs), Paired Grid-Scale Storage (8hrs), DER Aggregator)

Year	Paired Grid-Scale Storage (6hr)		Paired Grid-Scale Storage (8hr)		DER Aggregator - PV+Storage	
	Capital ($/kW)	O&M ($/kW-year)	Capital ($/kW)	O&M ($/kW-year)	Capital ($/kW)	O&M ($/kW-year)
2020	1,033 ~~2,030~~	- ~~41~~	1,378 ~~2,616~~	- ~~41~~	5,424 ~~5,836~~	63 ~~82~~
2021	1,026 ~~1,951~~	- ~~40~~	1,368 ~~2,513~~	- ~~40~~	5,227 ~~5,578~~	60 ~~79~~
2022	1,018 ~~1,868~~	- ~~38~~	1,357 ~~2,404~~	- ~~38~~	5,025 ~~5,303~~	58 ~~76~~
2023	1,064 ~~1,875~~	- ~~36~~	1,418 ~~2,412~~	- ~~36~~	5,134 ~~5,354~~	55 ~~73~~
2024	1,053 ~~1,979~~	- ~~34~~	1,404 ~~2,564~~	- ~~34~~	6,689 ~~6,843~~	52 ~~69~~
2025	1,042 ~~1,849~~	- ~~33~~	1,389 ~~2,397~~	- ~~33~~	6,458 ~~6,480~~	49 ~~66~~
2026	1,187 ~~1,808~~	- ~~32~~	1,583 ~~2,343~~	- ~~32~~	6,106 ~~6,162~~	46 ~~64~~
2027	1,171 ~~1,693~~	- ~~32~~	1,562 ~~2,215~~	- ~~32~~	5,829 ~~5,968~~	42 ~~61~~
2028	1,154 ~~1,648~~	- ~~31~~	1,538 ~~2,156~~	- ~~31~~	5,490 ~~5,652~~	39 ~~59~~
2029	1,135 ~~1,600~~	- ~~31~~	1,513 ~~2,092~~	- ~~31~~	5,147 ~~5,320~~	36 ~~56~~
2030	1,115 ~~1,549~~	- ~~30~~	1,486 ~~2,025~~	- ~~30~~	4,807 ~~4,976~~	32 ~~53~~
2031	1,128 ~~1,568~~	- ~~30~~	1,504 ~~2,048~~	- ~~30~~	4,865 ~~5,032~~	32 ~~54~~

2032	1,141 ~~1,588~~	- ~~31~~	1,522 ~~2,071~~	- ~~31~~	4,922 ~~5,087~~	33 ~~55~~
2033	1,155 ~~1,607~~	- ~~31~~	1,540 ~~2,093~~	- ~~31~~	4,979 ~~5,143~~	33 ~~56~~
2034	1,168 ~~1,626~~	- ~~31~~	1,557 ~~2,116~~	- ~~31~~	5,037 ~~5,198~~	34 ~~56~~
2035	1,181 ~~1,645~~	- ~~31~~	1,575 ~~2,138~~	- ~~31~~	5,094 ~~5,253~~	34 ~~57~~
2036	1,195 ~~1,663~~	- ~~32~~	1,593 ~~2,160~~	- ~~32~~	5,152 ~~5,307~~	35 ~~58~~
2037	1,208 ~~1,682~~	- ~~32~~	1,611 ~~2,181~~	- ~~32~~	5,209 ~~5,362~~	35 ~~58~~
2038	1,221 ~~1,700~~	- ~~32~~	1,628 ~~2,202~~	- ~~32~~	5,266 ~~5,416~~	36 ~~59~~
2039	1,235 ~~1,718~~	- ~~33~~	1,646 ~~2,222~~	- ~~33~~	5,323 ~~5,470~~	36 ~~60~~
2040	1,248 ~~1,735~~	- ~~33~~	1,664 ~~2,243~~	- ~~33~~	5,380 ~~5,523~~	36 ~~60~~
2041	1,261 ~~1,753~~	- ~~33~~	1,681 ~~2,262~~	- ~~33~~	5,436 ~~5,576~~	37 ~~61~~
2042	1,274 ~~1,770~~	- ~~34~~	1,699 ~~2,281~~	- ~~34~~	5,493 ~~5,628~~	37 ~~62~~
2043	1,287 ~~1,786~~	- ~~34~~	1,716 ~~2,300~~	- ~~34~~	5,549 ~~5,680~~	38 ~~62~~
2044	1,300 ~~1,802~~	- ~~34~~	1,733 ~~2,318~~	- ~~34~~	5,604 ~~5,731~~	38 ~~63~~
2045	1,313 ~~1,818~~	- ~~34~~	1,750 ~~2,336~~	- ~~34~~	5,659 ~~5,781~~	39 ~~64~~
2046	1,325 ~~1,834~~	- ~~35~~	1,767 ~~2,352~~	- ~~35~~	5,717 ~~5,830~~	39 ~~65~~
2047	1,338 ~~1,848~~	- ~~35~~	1,784 ~~2,368~~	- ~~35~~	5,776 ~~5,879~~	40 ~~65~~
2048	1,351 ~~1,863~~	- 35	1,801 ~~2,384~~	- 35	5,834 ~~5,927~~	40 66
2049	1,363 ~~1,876~~	- ~~35~~	1,817 ~~2,398~~	- ~~35~~	5,892 ~~5,974~~	41 ~~67~~

2050	1,375 ~~1,890~~	- ~~36~~	1,833 ~~2,412~~	- ~~36~~	5,948 ~~6,020~~	41 ~~67~~

Table A-7: Capital and O&M Costs for Resource Options (Synchronous Condenser, Geothermal, Municipal Solid Waste)

Year	Synchronous Condenser	Geothermal		Municipal Solid Waste (MSW)		
	Capital ($/kVar)	Capital ($/kW)	O&M ($/kW-year)	Capital ($/kW)	O&M ($/kW-year)	Var O&M ($/MWH)
2020	1,255 ~~1,255~~	6,295 ~~8,869~~	219 ~~219~~	1,870 ~~1,870~~	24 ~~24~~	7 ~~7~~
2021	1,272 ~~1,272~~	6,380 ~~8,989~~	223 ~~223~~	1,908 ~~1,908~~	24 ~~24~~	8 ~~8~~
2022	1,296 ~~1,296~~	6,465 ~~9,109~~	226 ~~226~~	1,946 ~~1,946~~	25 ~~25~~	8 ~~8~~
2023	1,299 ~~1,299~~	6,552 ~~9,230~~	230 ~~230~~	1,979 ~~1,979~~	26 ~~26~~	8 ~~8~~
2024	1,314 ~~1,314~~	6,638 ~~9,352~~	234 ~~234~~	2,023 ~~2,023~~	26 ~~26~~	8 ~~8~~
2025	1,340 ~~1,340~~	6,725 ~~9,475~~	238 ~~238~~	2,071 ~~2,071~~	27 ~~27~~	8 ~~8~~
2026	1,361 ~~1,361~~	6,813 ~~9,598~~	242 ~~242~~	2,108 ~~2,108~~	27 ~~27~~	8 ~~8~~
2027	1,372 ~~1,372~~	6,901 ~~9,722~~	246 ~~246~~	2,146 ~~2,146~~	28 ~~28~~	9 ~~9~~
2028	1,393 ~~1,393~~	6,989 ~~9,847~~	250 ~~250~~	2,184 ~~2,184~~	29 ~~29~~	9 ~~9~~
2029	1,416 ~~1,416~~	7,078 ~~9,972~~	254 ~~254~~	2,222 ~~2,222~~	29 ~~29~~	9 ~~9~~
2030	1,442 ~~1,442~~	7,167 ~~10,097~~	258 ~~258~~	2,259 ~~2,259~~	30 ~~30~~	9 ~~9~~
2031	1,470 ~~1,470~~	7,297 ~~10,281~~	264 ~~264~~	2,298 ~~2,298~~	31 ~~31~~	10 ~~10~~
2032	1,494 ~~1,494~~	7,429 ~~10,467~~	270 ~~270~~	2,334 ~~2,334~~	32 ~~32~~	10 ~~10~~

2033	1,519 ~~1,519~~	7,564 ~~10,658~~	276 ~~276~~	2,368 ~~2,368~~	32 ~~32~~	10 ~~10~~
2034	1,546 ~~1,546~~	7,702 ~~10,851~~	283 ~~283~~	2,407 ~~2,407~~	33 ~~33~~	10 ~~10~~
2035	1,574 ~~1,574~~	7,842 ~~11,048~~	290 ~~290~~	2,446 ~~2,446~~	34 ~~34~~	10 ~~10~~
2036	1,600 ~~1,600~~	7,984 ~~11,249~~	296 ~~296~~	2,484 ~~2,484~~	35 ~~35~~	11 ~~11~~
2037	1,628 ~~1,628~~	8,129 ~~11,453~~	303 ~~303~~	2,523 ~~2,523~~	35 ~~35~~	11 ~~11~~
2038	1,657 ~~1,657~~	8,277 ~~11,661~~	310 310	2,564 ~~2,564~~	36 36	11 11
2039	1,689 ~~1,689~~	8,427 ~~11,873~~	317 ~~317~~	2,607 ~~2,607~~	37 ~~37~~	11 ~~11~~
2040	1,716 ~~1,716~~	8,580 ~~12,089~~	325 ~~325~~	2,648 ~~2,648~~	38 ~~38~~	12 ~~12~~
2041	1,747 ~~1,747~~	8,736 ~~12,309~~	332 ~~332~~	2,688 ~~2,688~~	39 ~~39~~	12 ~~12~~
2042	1,777 ~~1,777~~	8,895 ~~12,532~~	340 ~~340~~	2,731 ~~2,731~~	40 ~~40~~	12 ~~12~~
2043	1,809 ~~1,809~~	9,057 ~~12,760~~	348 ~~348~~	2,776 ~~2,776~~	41 ~~41~~	13 ~~13~~
2044	1,841 ~~1,841~~	9,221 ~~12,992~~	356 ~~356~~	2,821 ~~2,821~~	42 ~~42~~	13 ~~13~~
2045	1,875 ~~1,875~~	9,389 ~~13,228~~	364 ~~364~~	2,869 ~~2,869~~	43 ~~43~~	13 ~~13~~
2046	1,908 ~~1,908~~	9,559 ~~13,468~~	373 ~~373~~	2,914 ~~2,914~~	44 ~~44~~	13 ~~13~~
2047	1,942 ~~1,942~~	9,733 ~~13,712~~	382 ~~382~~	2,959 ~~2,959~~	45 ~~45~~	14 ~~14~~
2048	1,976 ~~1,976~~	9,910 ~~13,962~~	390 ~~390~~	3,003 ~~3,003~~	46 ~~46~~	14 ~~14~~
2049	2,007 ~~2,007~~	10,090 ~~14,215~~	400 ~~400~~	3,049 ~~3,049~~	47 ~~47~~	14 ~~14~~
2050	2,030 ~~2,030~~	10,273 ~~14,473~~	409 409	3,065 ~~3,065~~	48 48	15 ~~15~~

Table A-8: Capital and O&M Costs for Resource Options (Biomass)

Year	Biomass			
	Capital ($/kW)	O&M ($/kW-year)	Var O&M ($/MWH)	Fuel Cost ($/~~MWH~~MM~~mm~~BTU)
2020	5,985 ~~5,985~~	182 ~~182~~	6 ~~6~~	4 ~~4~~
2021	6,106 ~~6,106~~	186 ~~186~~	6 ~~6~~	4 ~~4~~
2022	6,228 ~~6,228~~	190 ~~190~~	6 ~~6~~	4 ~~4~~
2023	6,331 ~~6,331~~	195 ~~195~~	6 ~~6~~	4 ~~4~~
2024	6,475 ~~6,475~~	199 ~~199~~	6 ~~6~~	4 ~~4~~
2025	6,626 ~~6,626~~	204 ~~204~~	7 ~~7~~	4 ~~4~~
2026	6,745 ~~6,745~~	209 ~~209~~	7 ~~7~~	4 ~~4~~
2027	6,868 ~~6,868~~	213 ~~213~~	7 ~~7~~	5 ~~5~~
2028	6,990 ~~6,990~~	218 ~~218~~	7 ~~7~~	5 ~~5~~
2029	7,111 ~~7,111~~	224 ~~224~~	7 ~~7~~	5 ~~5~~
2030	7,227 ~~7,227~~	229 ~~229~~	7 ~~7~~	5 ~~5~~
2031	7,353 ~~7,353~~	234 ~~234~~	7 ~~7~~	5 ~~5~~
2032	7,468 ~~7,468~~	239 ~~239~~	8 ~~8~~	5 ~~5~~
2033	7,579 ~~7,579~~	245 ~~245~~	8 ~~8~~	5 ~~5~~
2034	7,703 ~~7,703~~	251 ~~251~~	8 ~~8~~	5 ~~5~~
2035	7,827 ~~7,827~~	257 ~~257~~	8 ~~8~~	5 ~~5~~
2036	7,948 ~~7,948~~	263 ~~263~~	8 ~~8~~	6 ~~6~~
2037	8,075 ~~8,075~~	269 ~~269~~	9 ~~9~~	6 ~~6~~
2038	8,206 ~~8,206~~	275 ~~275~~	9 ~~9~~	6 ~~6~~
2039	8,342 ~~8,342~~	281 ~~281~~	9 ~~9~~	6 ~~6~~
2040	8,474 ~~8,474~~	288 ~~288~~	9 ~~9~~	6 ~~6~~
2041	8,602 ~~8,602~~	295 ~~295~~	9 ~~9~~	6 ~~6~~
2042	8,741 ~~8,741~~	301 ~~301~~	10 ~~10~~	6 ~~6~~
2043	8,883 ~~8,883~~	308 ~~308~~	10 ~~10~~	7 ~~7~~
2044	9,027 ~~9,027~~	316 ~~316~~	10 ~~10~~	7 ~~7~~
2045	9,180 ~~9,180~~	323 ~~323~~	10 ~~10~~	7 ~~7~~

2046	9,326 ~~9,326~~	331 ~~331~~	11 ~~11~~	7 ~~7~~
2047	9,468 ~~9,468~~	338 ~~338~~	11 ~~11~~	7 ~~7~~
2048	9,610 ~~9,610~~	346 346	11 11	7 7
2049	9,757 ~~9,757~~	354 ~~354~~	11 ~~11~~	8 ~~8~~
2050	9,808 ~~9,808~~	362 ~~362~~	12 ~~12~~	8 ~~8~~

Table A-9: Capital and O&M Costs for Resource Options (Concentrated Solar, Combined Cycle)

Year	Concentrated Solar			Combined Cycle		
	Capital ($/kW)	O&M ($/kW-year)	Var O&M ($/MWH)	Capital ($/kW)	O&M ($/kW-year)	Var O&M ($/MWH)
2020	7,785 ~~7,425~~	80 ~~80~~	4 ~~4~~	1,420 ~~1,420~~	33 ~~33~~	2 ~~2~~
2021	7,644 ~~7,284~~	81 ~~81~~	4 ~~4~~	1,445 ~~1,445~~	34 ~~34~~	2 ~~2~~
2022	7,465 ~~7,105~~	81 ~~81~~	4 ~~4~~	1,476 ~~1,476~~	35 ~~35~~	2 ~~2~~
2023	7,704 ~~7,344~~	81 ~~81~~	4 ~~4~~	1,493 ~~1,493~~	35 ~~35~~	2 ~~2~~
2024	7,563 ~~8,366~~	81 ~~81~~	4 ~~4~~	1,521 ~~1,521~~	36 ~~36~~	2 ~~2~~
2025	7,446 ~~8,231~~	80 ~~80~~	4 ~~4~~	1,557 ~~1,557~~	37 ~~37~~	2 ~~2~~
2026	8,484 ~~8,124~~	80 ~~80~~	4 ~~4~~	1,586 ~~1,586~~	38 ~~38~~	2 ~~2~~
2027	8,404 ~~8,044~~	79 ~~79~~	4 ~~4~~	1,609 ~~1,609~~	39 ~~39~~	2 ~~2~~
2028	8,352 ~~7,992~~	78 ~~78~~	4 ~~4~~	1,639 ~~1,639~~	40 ~~40~~	3 ~~3~~
2029	8,328 ~~7,968~~	78 ~~78~~	4 ~~4~~	1,670 ~~1,670~~	41 ~~41~~	3 ~~3~~
2030	8,331 ~~7,971~~	77 ~~77~~	4 ~~4~~	1,702 ~~1,702~~	42 ~~42~~	3 ~~3~~
2031	8,360 ~~8,000~~	79 ~~79~~	5 ~~5~~	1,735 ~~1,735~~	43 ~~43~~	3 ~~3~~

2032	8,416 ~~8,056~~	81 ~~81~~	5 ~~5~~	1,768 ~~1,768~~	44 ~~44~~	3 ~~3~~
2033	8,497 ~~8,137~~	83 ~~83~~	5 ~~5~~	1,797 ~~1,797~~	45 ~~45~~	3 ~~3~~
2034	8,603 ~~8,243~~	84 ~~84~~	5 ~~5~~	1,833 ~~1,833~~	46 ~~46~~	3 ~~3~~
2035	8,732 ~~8,372~~	86 ~~86~~	5 ~~5~~	1,867 ~~1,867~~	47 ~~47~~	3 ~~3~~
2036	8,884 ~~8,524~~	88 ~~88~~	5 ~~5~~	1,900 ~~1,900~~	48 ~~48~~	3 ~~3~~
2037	9,057 ~~8,697~~	90 ~~90~~	5 ~~5~~	1,935 ~~1,935~~	49 ~~49~~	3 ~~3~~
2038	9,249 ~~8,889~~	93 ~~93~~	5 ~~5~~	1,974 ~~1,974~~	50 ~~50~~	3 ~~3~~
2039	9,459 ~~9,099~~	95 ~~95~~	5 ~~5~~	2,010 ~~2,010~~	51 ~~51~~	3 ~~3~~
2040	9,673 ~~9,313~~	97 ~~97~~	6 ~~6~~	2,048 ~~2,048~~	52 ~~52~~	3 ~~3~~
2041	9,892 ~~9,532~~	99 ~~99~~	6 ~~6~~	2,086 ~~2,086~~	54 ~~54~~	3 ~~3~~
2042	10,117 ~~9,757~~	101 ~~101~~	6 ~~6~~	2,125 ~~2,125~~	55 ~~55~~	4 ~~4~~
2043	10,346 ~~9,986~~	104 ~~104~~	6 ~~6~~	2,166 ~~2,166~~	56 ~~56~~	4 ~~4~~
2044	10,581 ~~10,221~~	106 ~~106~~	6 ~~6~~	2,207 ~~2,207~~	58 ~~58~~	4 ~~4~~
2045	10,821 ~~10,461~~	109 ~~109~~	6 ~~6~~	2,250 ~~2,250~~	59 ~~59~~	4 ~~4~~
2046	11,066 ~~10,706~~	111 ~~111~~	6 ~~6~~	2,294 ~~2,294~~	60 ~~60~~	4 ~~4~~
2047	11,317 ~~10,957~~	114 ~~114~~	7 ~~7~~	2,337 ~~2,337~~	62 ~~62~~	4 ~~4~~
2048	11,574 ~~11,214~~	117 117	7 7	2,377 ~~2,377~~	63 63	4 4
2049	11,836 ~~11,476~~	119 ~~119~~	7 ~~7~~	2,421 ~~2,421~~	65 ~~65~~	4 ~~4~~

2050	12,104	122 ~~122~~	7 ~~7~~	2,448 ~~2,448~~	66 ~~66~~	4 ~~4~~

Table A-10: Capital and O&M Costs for Resource Options (Combustion Turbine, Internal Combustion Engine)

Year	Combustion Turbine			Internal Combustion Engine		
	Capital ($/kW)	O&M ($/kW-year)	Var O&M ($/MWH)	Capital ($/kW)	O&M ($/kW-year)	Var O&M ($/MWH)
2020	1,255 ~~1,255~~	25 ~~25~~	6 ~~6~~	2,648 ~~2,648~~	37 ~~37~~	28 ~~28~~
2021	1,272 ~~1,272~~	26 ~~26~~	6 ~~6~~	2,684 ~~2,684~~	38 ~~38~~	29 ~~29~~
2022	1,296 ~~1,296~~	27 ~~27~~	6 ~~6~~	2,734 ~~2,734~~	39 ~~39~~	29 ~~29~~
2023	1,299 ~~1,299~~	27 ~~27~~	6 ~~6~~	2,740 ~~2,740~~	40 ~~40~~	30 ~~30~~
2024	1,314 ~~1,314~~	28 ~~28~~	7 ~~7~~	2,773 ~~2,773~~	41 ~~41~~	31 ~~31~~
2025	1,340 ~~1,340~~	28 ~~28~~	7 ~~7~~	2,827 ~~2,827~~	42 ~~42~~	31 ~~31~~
2026	1,361 ~~1,361~~	29 ~~29~~	7 ~~7~~	2,872 ~~2,872~~	43 ~~43~~	32 ~~32~~
2027	1,372 ~~1,372~~	30 ~~30~~	7 ~~7~~	2,894 ~~2,894~~	44 ~~44~~	33 ~~33~~
2028	1,393 ~~1,393~~	30 ~~30~~	7 ~~7~~	2,939 ~~2,939~~	45 ~~45~~	34 ~~34~~
2029	1,416 ~~1,416~~	31 ~~31~~	7 ~~7~~	2,988 ~~2,988~~	46 ~~46~~	34 ~~34~~
2030	1,442 ~~1,442~~	32 ~~32~~	8 ~~8~~	3,042 ~~3,042~~	47 ~~47~~	35 ~~35~~
2031	1,470 ~~1,470~~	33 ~~33~~	8 ~~8~~	3,101 ~~3,101~~	48 ~~48~~	36 ~~36~~
2032	1,494 ~~1,494~~	33 ~~33~~	8 ~~8~~	3,153 ~~3,153~~	49 ~~49~~	37 ~~37~~

2033	1,519 ~~1,519~~	34 ~~34~~	8 ~~8~~	3,205 ~~3,205~~	50 ~~50~~	38 ~~38~~
2034	1,546 ~~1,546~~	35 ~~35~~	8 ~~8~~	3,262 ~~3,262~~	51 ~~51~~	39 ~~39~~
2035	1,574 ~~1,574~~	36 ~~36~~	8 ~~8~~	3,320 ~~3,320~~	53 ~~53~~	40 ~~40~~
2036	1,600 ~~1,600~~	37 ~~37~~	9 ~~9~~	3,375 ~~3,375~~	54 ~~54~~	40 ~~40~~
2037	1,628 ~~1,628~~	37 ~~37~~	9 ~~9~~	3,435 ~~3,435~~	55 ~~55~~	41 ~~41~~
2038	1,657 ~~1,657~~	38 38	9 9	3,496 ~~3,496~~	56 56	42 42
2039	1,689 ~~1,689~~	39 ~~39~~	9 ~~9~~	3,563 ~~3,563~~	58 ~~58~~	43 ~~43~~
2040	1,716 ~~1,716~~	40 ~~40~~	9 ~~9~~	3,621 ~~3,621~~	59 ~~59~~	44 ~~44~~
2041	1,747 ~~1,747~~	41 ~~41~~	10 ~~10~~	3,685 ~~3,685~~	60 ~~60~~	45 ~~45~~
2042	1,777 ~~1,777~~	42 ~~42~~	10 ~~10~~	3,750 ~~3,750~~	62 ~~62~~	46 ~~46~~
2043	1,809 ~~1,809~~	43 ~~43~~	10 ~~10~~	3,816 ~~3,816~~	63 ~~63~~	48 ~~48~~
2044	1,841 ~~1,841~~	44 ~~44~~	10 ~~10~~	3,883 ~~3,883~~	65 ~~65~~	49 ~~49~~
2045	1,875 ~~1,875~~	45 ~~45~~	11 ~~11~~	3,957 ~~3,957~~	66 ~~66~~	50 ~~50~~
2046	1,908 ~~1,908~~	46 ~~46~~	11 ~~11~~	4,026 ~~4,026~~	68 ~~68~~	51 ~~51~~
2047	1,942 ~~1,942~~	47 ~~47~~	11 ~~11~~	4,097 ~~4,097~~	69 ~~69~~	52 ~~52~~
2048	1,976 ~~1,976~~	48 ~~48~~	11 ~~11~~	4,168 ~~4,168~~	71 ~~71~~	53 ~~53~~
2049	2,007 ~~2,007~~	49 ~~49~~	12 ~~12~~	4,235 ~~4,235~~	73 ~~73~~	55 ~~55~~
2050	2,030 ~~2,030~~	51 ~~51~~	12 12	4,284 ~~4,284~~	74 74	56 ~~56~~

Appendix E: Peak Forecasts (2020 – 2050)

Table E-1: O‘ahu Peak Forecast (MW)

Year	Underlying	DER (PV and BESS)	Energy Efficiency	Electric Vehicles	TOU	Peak Forecast
MW	A	B	C	D	E	F~~E~~ =A + B + C + D + E
2020	1,330	(5)	(258)	6	-	1,072
2021	1,405	(13)	(282)	8	-	1,117
2022	1,496	(30)	(297)	9	(0)	1,178
2023	1,517	(47)	(310)	11	(1)	1,169 ~~1,170~~
2024	1,~~552~~ 539	(~~58~~53)	(~~335~~327)	~~13~~ 14	(2)	1,171 ~~1,173~~
2025	1,579	(60)	(339)	16	(3)	1,193 ~~1,196~~
2026	1,569	(66)	(351)	19	(4)	1,167 ~~1,171~~
2027	1,589	(75)	(366)	23	(5)	1,168 ~~1,173~~
2028	1,590	(69)	(381)	29	(5)	1,164 ~~1,169~~
2029	1,617	(91)	(388)	33	(5)	1,166 ~~1,171~~
2030	1,642	(95)	(402)	39	(5)	1,179 ~~1,184~~
2031	1,667	(97)	(414)	46	(4)	1,198 ~~1,202~~
2032	1,683	(99)	(424)	54	(5)	1,210 ~~1,214~~
2033	1,703	(95)	(434)	62	(4)	1,231 ~~1,236~~
2034	1,712	(101)	(440)	72	(5)	1,238 ~~1,243~~
2035	1,718	(104)	(448)	82	(4)	1,243 ~~1,248~~
2036	1,738	(106)	(455)	94	(4)	1,267 ~~1,271~~
2037	1,762	(117)	(465)	106	(4)	1,283 ~~1,286~~
2038	1,780	(120)	(476)	121	(4)	1,301 ~~1,305~~
2039	1,792	(121)	(483)	135	(4)	1,319 ~~1,323~~
2040	1,736	(87)	(454)	145	(4)	1,335 ~~1,339~~
2041	1,747	(90)	(466)	177	(4)	1,365 ~~1,369~~
2042	1,639	(43)	(437)	237	(4)	1,393 ~~1,396~~
2043	1,852	(140)	(508)	223	(4)	1,423 ~~1,427~~
2044	1,800	(97)	(474)	241	(4)	1,466 ~~1,470~~

2045	1,702	(43)	(452)	286	(4)	1,490 ~~1,493~~
2046	1,682	(43)	(459)	359	(4)	1,535 ~~1,538~~
2047	1,704	(49)	(464)	392	(4)	1,578 ~~1,582~~
2048	1,707	(46)	(469)	424	(4)	1,611 ~~1,615~~
2049	1,712	(52)	(473)	453	(4)	1,635 ~~1,640~~
2050	1,721	(51)	(477)	473	(4)	1,661 ~~1,666~~

Table E-2: Hawai‘i Island Peak Forecast (MW)

Year	Underlying	DER (PV and BESS)	Energy Efficiency	Electric Vehicles	TOU	Peak Forecast
MW	A	B	C	D	E	F~~E~~ =A + B + C + D + E
2020	221.6	(0.8)	(29.5)	0.4	-	191.8
2021	218.8	(2.8)	(36.8)	0.6	-	179.8
2022	219.8	(4.2)	(35.7)	0.8	(0.2)	180.6 ~~180.8~~
2023	228.1	(6.1)	(43.0)	1.1	(0.5)	179.5 ~~180.1~~
2024	224.2	(6.6)	(41.0)	1.5	(0.7)	177.5 ~~178.1~~
2025	229.5	(10.0)	(42.6)	2.1	(1.3)	177.6 ~~178.9~~
2026	229.4	(7.2)	(45.8)	3.2	(1.6)	178.0 ~~179.6~~
2027	234.2	(12.2)	(47.8)	4.2	(1.7)	176.6 ~~178.3~~
2028	234.5	(10.4)	(50.7)	5.0	(1.5)	177.0 ~~178.5~~
2029	250.1	(21.0)	(58.1)	7.1	(2.3)	175.8 ~~178.1~~
2030	236.8	(12.5)	(55.5)	8.7	(1.5)	176.0 ~~177.5~~
2031	241.1	(17.9)	(57.0)	10.3	(1.9)	174.5 ~~176.5~~
2032	239.3	(12.1)	(60.7)	11.5	(1.7)	176.3 ~~178.1~~
2033	243.8	(15.5)	(62.3)	15.3	(1.5)	179.6 ~~181.2~~
2034	233.6	(3.2)	(68.9)	17.5	(1.9)	177.0 ~~178.9~~
2035	243.0	(9.0)	(74.7)	21.3	(2.3)	178.4 ~~180.6~~
2036	~~247.4~~249.3	(~~23.4~~22.8)	(~~67.1~~68.5)	~~23.6~~22.6	(1.9)	178.7 ~~180.6~~
2037	240.2	(3.3)	(72.8)	26.0	(1.9)	188.2 ~~190.2~~
2038	240.1	(3.3)	(74.0)	27.8	(1.9)	188.6 ~~190.5~~
2039	240.4	(5.4)	(76.1)	35.4	(2.1)	192.1 ~~194.3~~

2040	249.9	(10.8)	(84.2)	39.6	(2.2)	192.3 ~~194.5~~
2041	252.3	(22.2)	(75.7)	42.2	(1.5)	195.1 ~~196.6~~
2042	255.4246.3	(~~29.3~~26.3)	(~~77.6~~71.4)	48.147.8	(1.7)	194.8 196.6
2043	247.7	(3.4)	(82.2)	51.5	(1.9)	211.7 ~~213.6~~
2044	246.4	(5.8)	(82.7)	60.2	(2.1)	216.1 ~~218.1~~
2045	247.2	(3.4)	(85.3)	64.5	(1.9)	221.2 ~~223.1~~
2046	257.2	(12.5)	(93.5)	73.1	(2.2)	222.1 ~~224.3~~
2047	218.1	(2.8)	(73.1)	88.0	(1.5)	228.5 ~~230.1~~
2048	253.4	(3.5)	(89.0)	81.1	(1.9)	240.2 ~~242.1~~
2049	253.0~~1~~	(~~9.1~~3.5)	(~~93.6~~90.7)	~~91.2~~82.6	(1.9)	239.6 ~~241.6~~
2050	256.5	(3.8)	(99.6)	99.3	(2.1)	250.3 252.4

Table E-3: Maui Peak Forecast (MW)

Year	Underlying	DER (PV and BESS)	Energy Efficiency	Electric Vehicles	TOU	Peak Forecast
MW	A	B	C	D	E	F~~E~~ =A + B + C + D + E
2020	228.5 ~~229.7~~	(1.7)	(34.1)	1.3 ~~0.1~~	-	194.0
2021	236.0 ~~237.2~~	(3.2)	(38.5)	1.4 ~~0.2~~	-	195.7
2022	235.8 ~~236.9~~	(8.5)	(41.5)	1.8 ~~0.6~~	(0.2)	187.4 ~~187.5~~
2023	236.9 ~~238.0~~	(12.4)	(42.4)	2.2 ~~1.0~~	(0.3)	184.0 ~~184.2~~
2024	241.3 ~~242.4~~	(16.2)	(44.7)	2.7 ~~1.5~~	(0.7)	182.4 ~~183.0~~
2025	245.5 ~~246.7~~	(18.0)	(47.3)	3.4 ~~2.2~~	(0.8)	182.7 ~~183.6~~
2026	249.6 ~~250.8~~	(20.0)	(52.1)	4.8 ~~3.6~~	(1.0)	181.3 ~~182.3~~
2027	249.0 ~~250.2~~	(15.6)	(55.8)	6.7 ~~5.5~~	(1.1)	183.1 ~~184.3~~
2028	251.3 ~~252.5~~	(16.2)	(59.2)	8.4 ~~7.2~~	(1.1)	183.2 ~~184.3~~
2029	258.2 ~~259.5~~	(26.6)	(56.6)	9.9 ~~8.7~~	(1.1)	183.8 ~~185.0~~
2030	260.0 ~~261.1~~	(29.2)	(58.1)	12.5 ~~11.4~~	(1.2)	184.1 ~~185.2~~
2031	263.4 ~~254.0~~	(~~22.9~~31.2)	(~~58.0~~60.8)	14.8 ~~13.1~~	(1.2)	185.0 ~~186.2~~
2032	245.5 ~~246.6~~	(11.3)	(59.8)	17.4 ~~16.3~~	(1.1)	190.8 ~~191.8~~
2033	248.8 ~~250.0~~	(11.5)	(61.6)	22.2 ~~21.0~~	(1.1)	196.8 ~~197.9~~
2034	251.6 ~~252.8~~	(11.8)	(63.1)	27.6 ~~26.4~~	(1.1)	203.1 ~~204.2~~

2035	230.5 ~~231.7~~	(3.8)	(58.9)	37.6 ~~36.4~~	(1.0)	204.5 ~~205.4~~
2036	266.1 267.3	(21.6)	(76.7)	39.9 38.7	(1.5)	206.2 207.7
2037	256.0 ~~257.2~~	(13.0)	(66.5)	39.0 ~~37.8~~	(1.1)	214.4 ~~215.5~~
2038	259.2 260.4	(13.3)	(67.5)	41.4 40.2	(1.1)	218.7 219.8
2039	261.8 ~~263.0~~	(13.6)	(68.9)	47.7 ~~46.5~~	(1.1)	225.8 ~~226.9~~
2040	240.1 241.4	(3.9)	(64.6)	64.5 63.3	(0.9)	235.2 236.2
2041	242.4 ~~243.6~~	(5.8)	(64.3)	70.3 ~~69.1~~	(1.1)	241.4 ~~242.6~~
2042	244.7 245.8	(11.8)	(65.1)	76.2 75.1	(1.0)	243.1 244.0
2043	272.0 ~~273.2~~	(14.8)	(72.5)	65.2 ~~64.0~~	(1.1)	248.9 ~~249.9~~
2044	290.1 291.3	(29.5)	(81.4)	76.5 75.3	(1.0)	254.6 255.7
2045	254.2 ~~255.4~~	(4.1)	(67.7)	79.0 ~~77.8~~	(0.9)	260.4 ~~261.4~~
2046	250.9 252.2	(4.1)	(68.7)	95.0 93.8	(0.9)	272.2 273.2
2047	253.3 ~~254.5~~	(6.0)	(69.4)	99.3 ~~98.1~~	(1.1)	276.1 ~~277.1~~
2048	286.1 287.3	(16.0)	(76.9)	83.2 82.0	(1.1)	275.3 276.3
2049	256.9 ~~258.8~~	(~~16.7~~15.9)	(70.7)	108.7 ~~107.7~~	(0.9)	278.1 ~~279.2~~
2050	259.1 260.3	(16.8)	(71.2)	112.7 111.5	(1.1)	282.8 283.8

Table E-4: Moloka'i Peak Forecast (MW)

Year	Underlying	DER (PV and BESS)	Energy Efficiency	Electric Vehicles	TOU	Peak Forecast
MW	A	B	C	D	E	~~E~~F = A + B + C + D + E
2020	5.7	(0.0)	0.0	0.0	-	5.7
2021	5.7	(0.0)	(0.0)	0.0	-	5.6
2022	5.7	(0.0)	(0.1)	0.0	-	5.6
2023	5.7	(0.1)	(0.1)	0.0	(0.0)	5.5
2024	5.7	(0.1)	(0.1)	0.0	(0.0)	5.6
2025	5.8	(0.1)	(0.1)	0.0	(0.0)	5.6
2026	5.8	(0.1)	(0.1)	0.0	(0.0)	5.6
2027	~~5.7~~ 5.6	(0.1)	(~~0.2~~0.1)	0.0	0.0	5.5
2028	5.8	(0.1)	(0.1)	0.0	(0.0)	5.5
2029	~~5.8~~5.7	(~~0.2~~0.1)	(~~0.2~~0.1)	0.0	0.0	5.5 ~~5.6~~

2030	5.7 5.8	(0.1)	(~~0.2~~0.1)	0.00.1	0.0	5.5 ~~5.6~~
2031	5.7 ~~5.9~~	(0.2)	(0.2)	0.1	0.0	5.5 ~~5.6~~
2032	5.9	(0.2)	(0.2)	0.1	(0.0)	5.5 5.6
2033	~~5.9~~5.8	(0.2)	(~~0.3~~0.2)	0.1	0.0	5.6
2034	5.8	(0.2)	(0.2)	0.1	0.0	5.6
2035	~~6.1~~5.9	(0.2)	(~~0.3~~0.2)	0.1	0.0	5.7
2036	6.16.0	(~~0.3~~0.2)	(0.2)	0.1	0.0	5.7
2037	6.0	(0.2)	(0.2)	0.2	0.0	5.8 ~~5.7~~
2038	6.1	(0.2)	(0.2)	0.2	0.0	5.9
2039	6.1	(0.2)	(0.2)	0.2	0.0	5.9
2040	6.1	(0.2)	(0.2)	0.2	0.0	5.9
2041	6.1	(0.3)	(0.2)	0.3	0.0	5.9
2042	6.2	(0.3)	(0.2)	0.3	0.0	6.1 6.0
2043	6.2	(0.3)	(0.2)	0.4	0.0	6.1
2044	6.46.3	(0.3)	(~~0.3~~0.2)	0.50.4	0.0	6.2
2045	6.3	(0.3)	(0.2)	0.5	0.0	6.3
2046	6.3	(0.3)	(0.2)	0.5	0.0	6.4
2047	6.4	(0.3)	(0.2)	0.6	0.0	6.5
2048	6.4	(0.3)	(0.2)	0.6	0.0	6.5
2049	6.4	(0.3)	(0.2)	0.7	0.0	6.6
2050	6.5	(0.3)	(0.2)	0.8	0.0	6.7

Table E-5: Lānaʻi Peak Forecast (MW)

Year	Underlying	DER (PV and BESS)	Energy Efficiency	Electric Vehicles	TOU	Peak Forecast
MW	A	B	C	D	E	F~~E~~ =A + B + C + D + E
2020	5.9	(0.0)~~–~~	(0.0)~~–~~	0.0 ~~–~~	–	5.9
2021	6.3	(0.0)~~–~~	(0.0)~~–~~	0.0 ~~–~~	–	6.3
2022	6.3	(0.0)~~–~~	(0.0)~~–~~	0.0 ~~–~~	–	6.3
2023	6.5	(0.0)~~–~~	(0.1)	0.0 ~~–~~	(0.0)	6.4
2024	6.5	(0.0)~~–~~	(0.1)	0.0 ~~–~~	(0.0)	6.4

2025	6.5	(0.0)–	(0.1)	0.0 –	(0.0)	6.3 ~~6.4~~
2026	6.5	(0.0)–	(0.1)	0.0 –	(0.0)	6.3 ~~6.4~~
2027	6.6	(0.0)–	(0.1)	0.0 –	(0.0)	6.4 ~~6.5~~
2028	6.7	(0.0)–	(0.2)	0.0 –	(0.0)	6.4 6.5
2029	6.8	(0.1)	(0.2)	0.0 –	(0.0)	6.5
2030	6.8	(0.1)	(0.2)	0.0 –	(0.0)	6.5 6.6
2031	6.8	(0.1)	(0.2)	0.0 –	(0.0)	6.5
2032	6.8	(0.1)	(0.2)	0.0 –	(0.0)	6.5
2033	6.8	(0.1)	(0.2)	0.0 –	(0.0)	6.5
2034	6.9	(0.1)	(0.3)	0.1	(0.0)	6.6
2035	7.0	(0.1)	(0.3)	0.1	(0.0)	6.7
2036	7.0	(0.1)	(0.2)	0.1	(0.0)	6.7
2037	7.0	(0.1)	(0.3)	0.1	(0.0)	6.7
2038	7.0	(0.1)	(0.3)	0.1	(0.0)	6.7
2039	7.1	(0.1)	(0.3)	0.1	(0.0)	6.8
2040	7.2	(0.1)	(0.3)	0.1	(0.0)	6.9
2041	7.2	(0.1)	(0.3)	0.2	(0.0)	6.8 ~~6.9~~
2042	7.2	(0.2)	(0.3)	0.2	(0.0)	6.8 ~~6.9~~
2043	7.3	(0.2)	(0.3)	0.2	(0.0)	6.9 ~~7.0~~
2044	7.2	(0.1)	(0.4)	0.2	(0.0)	6.9 ~~7.0~~
2045	7.3	(0.2)	(0.4)	0.3	(0.0)	7.0
2046	7.4	(0.2)	(0.4)	0.3	(0.0)	7.1
2047	7.5	(0.2)	(0.4)	0.3	(0.0)	7.2
2048	7.4	(0.2)	(0.4)	0.3	(0.0)	7.2
2049	7.3	(0.2)	(0.4)	0.3	(0.0)	7.1
2050	7.5	(0.2)	(0.4)	0.4	(0.0)	7.3

Appendix F: Stakeholder Feedback

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October 1, 2021

Mr. Marc Asano
Director, Integrated Grid Planning
Hawaiian Electric Company, Inc.
P.O. Box 2750
Honolulu, Hawaii 96840-0001.

Dear Mr. Asano:

RE: Docket No. 2018-0165 Instituting a Proceeding to Investigate Integrated Grid Planning – Comments on Energy Efficiency Supply Curves and Non-Distributed Energy Resource Customer Time-of-Use Assumptions.

The purpose of this letter is to provide initial comments on the energy efficiency ("EE") supply curves and time-of-use ("TOU") analysis presented at the Hawaiian Electric Companies[1] Stakeholder Technical Working Group ("STWG") meeting on September 23, 2021.

A. EE Supply Curves.

The Consumer Advocate appreciates the work conducted by Applied Energy Group ("AEG") to develop potential bundling of energy efficiency resources to treat EE as a supply-side option within Integrated Grid Planning ("IGP"). At this time, the Consumer Advocate seeks additional information in order to better understand the potential of the various bundles. It is the Consumer Advocate's understanding that the set of measures for the bundles comes from the AEG Market Potential Study, where the various measures were subsequently classified according to their energy savings, winter versus summer peak impacts, levelized cost, and benefit-cost ratio, and then grouped together in bundles according to measures with similar characteristics, with the final bundles reflecting different levels of overall cost-effectiveness.[2] Within the Bundles

[1] Hawaiian Electric Company, Inc., Hawaiʻi Electric Light Company, Inc., and Maui Electric Company, Limited, are collectively referred to as the "Hawaiian Electric Companies."

[2] STWG Presentation Slides, September 7, 2021, at 34-37. AEG explains that the bundles were ultimately grouped together based on the benefit-cost ratios as opposed to levelized cost which do not capture peak-focused benefits. These bundles are named from A (most cost-effective with a

Summary and Costs spreadsheet, the total GWh potential for each bundle is provided from 2022 - 2050, along with its levelized cost for selected years. However, information on the composition of the bundles (i.e. measures ultimately included within each bundle in each year) is not presently included.[3] The Consumer Advocate notes that it would also be helpful to provide a breakdown of the measures included in each bundle for a given load curve. For example, based on the load curves provided for each program bundle in the Hourly Costs spreadsheet, perhaps a few representative load curves could show how the measure types stack up. This would help to better understand the temporal nature—which measures feed into the Peak Bundles versus Other Bundle—and where the potential for different measures lie. This, coupled with specifying the cost-effectiveness of the individual measures (and not just the cost-effectiveness of the overall bundle), would not only better inform the IGP process but also help to assess the resources that could be brought to bear for future short-term needs as in the case of the Emergency Demand Response Program. A better understanding of the composition of the bundles could also inform the likelihood of overlap between loads that are assumed to be reduced through energy efficiency versus the loads that are assumed to respond to TOU pricing.

Absent the additional information noted above, the Consumer Advocate is unable to evaluate and offer comments on the reasonableness of the EE supply curves.

B. TOU Analysis.

As the Consumer Advocate noted in the September 23, 2021 STWG meeting, further research on the potential for load-shifting in the commercial sector is needed, particularly due to the nature of the UHERO Study.[4] To this end, the Consumer Advocate found a recent paper by Qiu et al. (2018) that may be relevant in revisiting the available load-shifting studies on the commercial sector.[5] Qiu et al (2018) assess the impact of

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Total Resource Cost greater than or equal to 1.2) to D (least cost-effective with a Total Resource Cost less than 0.8).

3 Some summary information regarding the composition of bundles was shown during the September 23, 2021 STWG meeting. It is the Consumer Advocate's understanding that the Hawaiian Electric Companies are checking with AEG regarding the extent to which more information can be made available.

4 The UHERO Report that the Hawaiian Electric Companies appear to rely on in excluding the commercial class from load shifting within IGP is limited in nature as it is not a Pilot Study. It only provides a literature review of commercial and industrial sector load-shifting studies and attempts to draw connections between the literature and end-use load shapes for Hawaii as presented in the Navigant Report prepared for the Hawaiian Electric Companies for its Demand Response Program application in Docket No. 2015-0412, filed on December 30, 2015.

Wee, S. and Coffman, M. (2018). Integrating Renewable Energy: A Commercial Sector Perspective on Price-Responsive Load-Shifting. UHERO Report. https://uhero.hawaii.edu/integrating-renewable-energy-a-commercial-sector-perspective-on-price-responsive-load-shifting/

5 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.

TOU rates on summer electricity usage of business customers in the Phoenix metropolitan area in 2012, when Salt River Project first implemented an experimental voluntary TOU plan for business customers (designed for those with normal business hours between 8am – 5 or 6pm). They find elasticities of substitution that are similar to that in Aigner and Hirschberg (1985) which evaluate a randomized TOU pricing experiment involving small and medium sized firms served by Southern California Edison.[6] Such elasticities, though small, could be explored. The same statewide study of California prepared by Charles River Associates (2005) that is referenced in the AEG Market Potential Study and is used for the Hawaiian Electric Companies' low and high cases for the residential sector (substitution elasticity of -0.045 and -0.10, respectively)[7] also provides substitution elasticities for the commercial sector, which are notably larger than that found in Qiu et al (2018). In sum, the Consumer Advocate is suggesting that both the commercial and residential sector be considered in developing the TOU layer, and that a forecast that assumes zero impact on commercial sector load due to TOU may not be a reasonable input to a bookend analysis.

Regarding Hawaii-specific information, the Consumer Advocate believes it would be useful to understand what, if any, information regarding load-shifting, load reduction, and/or price responsiveness can be gleaned from historical data regarding the behavior of Hawaiian Electric Companies' commercial customers who are enrolled on TOU rates.

Finally, the Consumer Advocate notes that to the extent that there are no reasonable Hawaii-based or comparable studies that can inform forecasts for either the residential or commercial sectors, this may underscore the value of a well-designed pilot effort to test a number of different price differentials for both fixed and volumetric charges to better understand the potential impact of TOU (and Critical Peak Pricing ("CPP") on customer behavior. To be clear, the Consumer Advocate is not suggesting that the current IGP process be held up or suspended while such efforts are being made. However, implementing such a pilot may be useful to inform not only future IGP forecasts regarding the impacts of pricing but also near-term rate design analysis.

The Consumer Advocate appreciates the opportunity to provide these comments for the Hawaiian Electric Companies' consideration.

Sincerely yours,

/s/ Dean Nishina
Dean Nishina
Executive Director

DN:te

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[6] 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.

[7] STWG Presentation Slides, September 23, 2021, at 9.

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