BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAIʻI

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

<u>HAWAIIAN ELECTRIC COMPANIES'</u>
<u>REPLY TO PARTY COMMENTS AND COMMISSION QUESTIONS</u>

<u>AND</u>

<u>CERTIFICATE OF SERVICE</u>

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The Hawaiian Electric Companies[1] respectfully submit their reply to the party comments submitted on September 10, 2021[2] and response to the Commission's questions set forth in Order No. 37927.

I. INTRODUCTION

In Order No. 37927, Establishing a Procedural Schedule for the Updated Revised Inputs and Assumptions, issued on August 23, 2021 ("Order No. 37927"), the Commission established a procedural schedule to review the updated revised inputs and assumptions submitted by the Companies as a part of their August 19, 2021 Integrated Grid Planning ("IGP") Update ("August Update").[3]

[1] Hawaiian Electric Company, Inc. ("Hawaiian Electric"), Hawai‘i Electric Light Company, Inc. ("Hawai‘i Electric Light"), and Maui Electric Company, Limited ("Maui Electric"), are collectively referred to as the "Hawaiian Electric Companies" or "Companies."

[2] Comments were submitted by the Division of Consumer Advocacy ("Consumer Advocate"), Ulupono Initiative ("Ulupono"), County of Hawaii ("COH"), Progression Hawaii Offshore Wind ("PHOW"), and Blue Planet Foundation, Hawaii PV Coalition and Hawaii Solar Energy Association (collectively "Joint Parties").

[3] Order No. 37927 at 1.

The Commission asked the Consumer Advocate and Intervenors to answer certain questions as a part of their comments.[4] The Commission also allowed the Companies to reply to any element of the Consumer Advocate's or Intervenors' comments and address the Commission's questions.[5] The following provides the Companies' reply to the Consumer Advocate's and Intervenors' comments on the August Update and answers to the Commission's questions.[6]

II. BACKGROUND

On January 19, 2021, the Companies filed their first Review Point on the Inputs and Assumptions ("I&A") ("I&A Review Point"), for Hawaiian Electric's 2021 Integrated Grid Planning process which included stakeholder input incorporated over the previous two years of stakeholder engagement. In March 2021, the Hawaiian Electric Companies issued an updated Input and Assumptions document reflecting stakeholder feedback that was summarized in the IGP Stakeholder Feedback Summary, March 2021.[7]

The Companies' August Update provides an overview of how the inputs and assumptions are used by the RESOLVE and PLEXOS models to develop grid needs and reflects the most recent feedback received from stakeholders throughout the IGP process to date consistent with the Commission's Order No. 37730. In particular, the August Update implements the directives of Order No. 37730 which includes: the Technical Advisory Panel ("TAP") "has thoroughly reviewed the revised Draft IGP Inputs and Assumptions, stakeholders have had ample

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[4] *Id.* at 3.

[5] *Id.* at 5.

[6] As a number of comments are lengthy, contain detailed recommendations and/or go beyond direct responses to the questions set forth in Order No. 37927, the Companies have, where appropriate, reiterated the parties' comments for ease of review and context (citations omitted).

[7] *See* Hawaiian Electric's Reply Comments to Stakeholder inputs on the IGP First Review Point filed on March 4, 2021 in Docket No. 2018-0165 Instituting a Proceeding to Investigate Integrated Grid Planning, ("March 4 Reply Comments") available at: https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/dkt_2018_0165_20210304_HECO_reply_comments.pdf

opportunity to provide corrective feedback, and the Companies have either incorporated that feedback, or clearly explained why it did not."[8] The inputs and assumptions described in the August Update include:

- Sales forecast by forecast layer for the underlying load, distributed energy resource, energy efficiency, and electrification of transportation layers
- Fuel price forecast
- Resource cost forecast
- Scenarios and sensitivities
- Additional assumptions used to characterize the existing and planned resource portfolio

Notably, certain key inputs and assumptions had broad agreement amongst stakeholders, including: general consensus on sales and peak forecasts, inclusion of warming trends based on Forecast Assumptions Working Group feedback, stakeholder comments acknowledging that the base EV forecast and treatment of managed and unmanaged charging are reasonable, and modeling scenarios and sensitivities that were vetted through the Stakeholder Council and the TAP. In addition, the TAP had previously reviewed the regulating reserve definitions, in which the Companies incorporated additional analyses to examine different time durations and confidence intervals. The TAP also indicated the prudency of the Company's proposal to transition to a reliability planning criteria that uses a new methodology that evaluates all hours of the year and chronological operations of the grid (Energy Reserve Margin).

On April 14, 2021, the Commission issued Order No. 37730 Directing Hawaiian Electric to File Revised Forecasts and Assumptions ("Review Point Guidance"), to address certain inputs and assumptions that warranted further discussion with stakeholders. Since April 2021, the

[8] Order No. 37730 at 53-54.

Companies have been engaged with stakeholders to address the remaining items highlighted in the Review Point Guidance. The ten key areas include:[9]

(1) adjust resource/technology cost projections;

(2) adjust fuel price forecasts;

(3) adjust and better explain its DER and load forecasts;

(4) provide qualitative and quantitative summaries of LoadSEER findings and disaggregated location-specific load forecasts;

(5) provide the results of the probabilistic DER hosting capacity analysis from the Synergi circuit models;

(6) demonstrate how the probabilistic forecasts developed with LoadSEER will inform the different reference case load forecast scenarios to be established using the "bookends" approach;

(7) develop a retirement schedule for the baseline forecast;

(8) further develop and clearly explain its modeling sensitivities;

(9) better explain and analytically support its grid services and planning criteria; and

(10) work with AEG to develop modeling inputs for energy efficiency.

Section 2 of the August Update describes the approximately 17 stakeholder meetings held since the issuance of the Review Point Guidance, including a summary of areas of consensus reached to modify the I&A consistent with the Review Point Guidance, and areas where stakeholders may disagree with the Company's decision on certain inputs or assumptions. In total, the Company and stakeholders have logged over 34 hours of engagement since April 2021, with deep and detailed engagement from the Stakeholder Council, TAP, and STWG. In addition to the Commission Staff, other parties to this docket have significantly contributed, including, the Consumer Advocate, Ulupono, Life of the Land, Blue Planet Foundation ("Blue Planet"), DER Parties, and Progression Hawaii Offshore Wind. Along with the many formal meetings, subsequent follow up discussions have taken place, with email correspondence to exchange data and information, which in sum, have shaped the revised I&A.

[9] Review Point Guidance at 51-52.

As noted in the Companies' updated workplans filed on June 18, 2021, and July 28, 2021 in this docket, some items cannot be completed until certain inputs and assumptions are finalized or otherwise require more time to develop. Specifically, the summaries of LoadSEER findings and disaggregated location-specific load forecasts (item 4, above), demonstration of how the probabilistic forecasts developed with LoadSEER will inform the different reference case load forecast scenarios (item 5), analytical support for grid service and planning criteria (item 9), and development of energy efficiency supply curves with AEG (item 10). These remaining items are expected to be filed along with the Grid Needs Assessment deliverable Review Point by early November 2021.[10]

Regarding the LoadSEER location specific forecasts, in order to meet the November deadline, the Companies will use the current high and low bookend forecasts described in the August Update, which have been vetted through stakeholders, to develop the location specific forecasts. Regarding the planning criteria, the Companies are continuing to engage the TAP and seek their independent review on the reasonableness of the long-range planning criteria for IGP purposes. Long-range reliability planning criteria may be applied at a more coarse level than analyses used to evaluate short-term reliability needs. The Companies have already started this process, with the filing of the TAP's independent review on June 1, 2021 of modeling methods, which included a review of the IGP modeling framework and tools, allowing RESOLVE to optimize energy storage paired with solar, the recommended approach to support the energy reserve margin planning criteria, and the provision of "virtual" inertia from inverter based resources. As discussed at the June 23, 2021 Stakeholder Council meeting and subsequent smaller group meetings, the Companies are currently transitioning the TAP leadership to a new

[10] *See* Status Update Letter to Commission filed on September 15, 2021 in this proceeding.

Chair and reviewing the core membership of the TAP in response to the Review Point Guidance to add a TAP member. The Company is actively working with stakeholders, including Commission Staff on modifications to the TAP.

As the Commission noted in its Review Point Guidance, "there is inherent uncertainty in predicting the future, so it is impossible to determine the accuracy of a forecast result a priori."[11] Accordingly, and consistent with Commission guidance, the Companies have strived to employ best practices, focus on stakeholder engagement, develop appropriate scenarios and sensitivities, and demonstrate forecasting rigor and reasonableness through transparent justification of their forecast to stakeholders and the Commission.[12]

The Companies believes that the stakeholder engagement activities since April 2021 have substantially improved the IGP inputs and assumptions. As such, the IGP process is now well positioned to identify near-term and long-term grid needs portfolios that will provide a range of options to assist the Company, stakeholders, and Commission to make informed decisions on solution sourcing. The inputs and assumptions are designed to have the support of stakeholders that have been involved in the process as a substantial majority of the changes described herein are responsive to stakeholders and the Review Point Guidance. The Companies look forward to Commission acceptance of the forecasts, inputs and assumptions so that the modeling work to identify grid needs can start in earnest. Through Stakeholder Council and working group discussions, stakeholders are also eager to move forward with the next phases of the IGP process and start the process of modeling analysis.

[11] Order No. 37730 at 54-55.

[12] *Id.*

III. REPLY TO COMMENTS

Comments were received from the Consumer Advocate, Ulupono, COH, PHOW, and the Joint Parties. The Companies reply to these parties' comments and questions as follows:

A. Reply to Consumer Advocate Comments

1. Item CA-1

> **THE COMPANIES SHOULD PROVIDE FURTHER SUPPORT FOR THEIR ELECTRIC VEHICLE FORECASTS.** At the June 4, 2021 Technical Conference, Hawaiian Electric proposed using its low and high forecasts, which reflect a 30% decrease and increase from the base case, respectively. In response to questions around the low EV forecast, the Consumer Advocate suggested Hawaiian Electric map out the corresponding level of new EV sales that would need to occur in order to attain the projected share of EVs on the road in order to provide context for the reasonableness of the forecast.
>
> …
>
> Given that the number of EVs on the road and their usage (vehicle miles travelled) largely determine the load forecast attributable to EVs, the Consumer Advocate emphasizes the need to reexamine the underlying assumptions in combination with other benchmarks to provide a realistic assessment.[13] (footnotes omitted) In a footnote to this section the Consumer Advocate also requested that "Hawaiian Electric file all underlying assumptions and outputs relating to the low and high forecasts similar to the base case (i.e. number of EVs, EV penetration, vehicle miles travelled, daily kWh, MWh sales per vehicle by island). In addition, as the "high" case has currently been revised to reflect 100% EVs on the road by 2045, please also provide accompanying spreadsheets.[14]

Hawaiian Electric Response:

The example high and low EV saturation scenarios presented at the January 29, 2020 FAWG in slides 52 to 54 were developed with Integral Analytics using the same methodology as the base forecast, a Bass Diffusion model combined with a geospatial, customer level agent-based model, and adjusting variables such as vehicle costs, gas prices, and tax credits. They do not represent 30% higher and 30% lower than the base forecast. High and low scenarios defined as 30% higher and 30% lower than the base forecast were proposed in the Company's March 4

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[13] Consumer Advocate Comments at 4-5.

[14] Consumer Advocate Comments at footnote 5.

Reply Comments on the first review point.[15] After further discussion with the TAP and STWG, the Company used the low scenarios presented at the January 29, 2020 FAWG and a 100% EV by 2045 scenario based on the Transcending Oil[16] report, as proposed by Blue Planet, as the high scenario in the August Update. All scenarios presented and proposed differ in the EV penetration percentages and resulting number of EVs. The other underlying assumptions of total light duty vehicles, vehicle miles travelled, daily kWh and MWh sales per vehicle by island are the same across all scenarios. Attachment 1 provides the percent EV penetration and number of EVs for the base, high and low scenarios included in the August Update workbook and the January 29, 2020 FAWG example high scenarios.

2. Item CA-2

> Using other benchmarks to help gauge the reasonableness of the forecasts is not only important for the low case, but also in light of revisions to the high EV forecast—from an original 30% increase in the share of EVs on the road from the base case to 100% ZEV saturation by 2045 (as provided in the Transcending Oil Report). The Consumer Advocate recognizes the intent of the high EV adoption scenario to capture the best-case scenario of meeting the four county mayors' commitment to a 100% renewable ground transportation and the State's net negative carbon target by 2045 (HRS 225-P), but raises, consistent with the notes from the June 4, 2021 Technical Conference, whether it would also be appropriate to consider a less aggressive pathway given the large divergence between the base case of 51% EVs on the road (and the tension between overbuilding and underbuilding EV infrastructure). Though much of the emphasis is on the share of EVs on the road to inform the load forecasts, it is helpful to consider how these forecasts corresponds to the share of new EV sales. As currently proposed, reaching 100% saturation by 2045 would require 100% of new light-duty vehicle sales on Oahu to be electric in 2030. This is in stark contrast to Hawaii's new EV market share in 2020 of 5.3%. Given this, it would be helpful to consider what the new EV market share would be in 2030 and 2045 be under Hawaiian Electric's original high forecast (30% increase from the base case) and whether such a scenario also be considered. The Consumer Advocate views the 100% EV saturation scenario as more of an "Ultra high" scenario and believes additional flexibility should be built into the planning process to accommodate deviations from forecasts. This would help mitigate the impact to customers to the extent that

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[15] *See* March 4 Reply Comments.

[16] Transcending Oil: Hawaii's Path to a Clean Energy Economy (April 2018), available at: https://elementalexcelerator.com/transcending-oil/

infrastructure investment needs are related to policy goals, which the Consumer Advocate believes should not be funded solely or mostly through utility rates.[17] (footnotes omitted)

Hawaiian Electric Response:

Using the high EV adoption scenario as a component of the high load bookend provides a total load forecast scenario that will test whether and how the resource plan would need to change to serve higher future customer load consistent with the following recommendations from the TAP and STWG:

TAP Comments:

> It was also noted that risks associated with uncertainty and accuracy may be different for different users of the forecasts. Depending on how the forecast is to be used, significant accuracy may be required, while for other use cases, it is a not-to-exceed number. It is important that adequate scenarios be analyzed to know which side of the error (positive or negative) is riskier for a given use case. <u>For example, the risk of not procuring enough capacity could be worse than having too much</u>…[18] (emphasis added)
>
> There was significant discussion concerning uncertainty and value of conducting "bookend' analyses to test the sensitivity of models and resulting portfolios against a wide range of load forecasts. The TAP recommends that bookend analyses be conducted to understand the potential high and low load forecast potential that could reasonably occur. The impact of error in any individual layer may be more impactful when it changes the daily profile.
>
> HECO should consider testing the sensitivity of models and resulting portfolios by running bookend scenarios that utilize the cumulative potential high and low load forecasts for each layer.
>
> HECO should <u>consider using a wider range of future energy efficiency and EV adoption rates due to the high uncertainty, especially beyond year 10</u>. The TAP noted that proposed retirement of thermal units might be impacted by this uncertainty.[19] (emphasis added)

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[17] *Id*. at 5-6.

[18] *See* Hawaiian Electric's Updated Workplan and First Review Point filed on January 19, 2021 in Docket No. 2018-0165 Instituting a Proceeding to Investigate Integrated Grid Planning, Exhibit A.3 at 3-4, available at https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/dkt_20180165_20210119_HECO_IGP_updated_workplan_review_point.pdf.

[19] *Id*. at Exhibit A.3 at 4.

Regarding whether the base EV forecast is reasonable, the TAP commented:
EV curves at other utilities look similar… little adoption early on, and then accelerated growth. Then curves bend up in time as ICE v. EV. The longer-term trend is very challenging to forecast accurately. Other utilities share similar EV trends, where adoptions starts increasing significantly after the 2020s, with a similar shape to the growth trend. Both vehicle performance and incentives are likely to have significant impact on this behavior so may need to adjust going forward.[20]

STWG Comments:

Stakeholder: The objective of the bookend would be to determine the lowest and highest possible demand. Does it change the resource mix dramatically? If the same types of resources are selected, then perhaps we shouldn't focus so much time on one bookend, e.g., increased EV uptake, etc.

Stakeholder: Test the high and low end bookends first to determine the impacts, and then go into a more granular analysis[21]

In applying the TAP and STWG's recommendations, if the higher load bookend compared to base case does not result in significant resource additions or cost increases then the resulting grid needs are robust against uncertain futures, especially with respect to the EV forecast. This would then mean a less aggressive high EV forecast would not need to be evaluated. However, depending on the results of the resource plan analysis, it may be appropriate to test lower load forecasts to further explore the resource plan sensitivity to load. For example, if there is a significant cost difference, then there could be flexibility in the planning process to evaluate a less aggressive high EV adoption scenario. This is consistent with the modeling framework presented at the June 4 Technical Conference where the process allows iterations to be completed on an as needed basis. The 100% ZEV by 2045 high EV scenario is not necessarily intended to be used to drive future investment in EV charging infrastructure or

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[20] *Id.* at 7.

[21] Meeting Notes to the July 14, 2021 STWG Meeting available at https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/stakeholder_technical/20210714_stwg_meeting_summary_notes.pdf

other system upgrades; rather to test the robustness of the resource plans. As a point of clarification, the Companies believe the base case includes a set of customer adoption forecasts based on what is most likely to happen. The high forecast is not constructed based on what is most likely to happen or that is necessarily the most realistic; rather it is driven by potential policy outcomes (*i.e.*, 100% ZEV by 2045) for which the Companies may need to adequately plan for and consider in its long-term planning.

The Companies' EV forecasts were developed as EV saturation curves, which represent the percent of vehicles on the road. The EV market share (*i.e.*, percent of new vehicle sales) was not derived as part of the forecast development process. However, in light of the Consumer Advocate's request to consider the EV market share in 2030 and 2045 necessary to achieve the Companies' example high forecast, an analysis was performed to estimate these values. The estimated EV market share needed to attain the example high forecasts as presented on January 29, 2020 would be approximately 25% of new vehicle sales in 2030 and 100% of new vehicle sales in 2045.

3. Item CA-3

> **THE UNDERLYING ASSUMPTIONS BEHIND THE ENERGY EFFICIENCY FORECASTS SHOULD BE PROVIDED.** As Hawaiian Electric continues to work with Applied Energy Group ("AEG") to develop supply curves and likewise adjust its energy efficiency layers due to potential double-counting, the Consumer Advocate seeks to better understand and evaluate the assumptions behind the forecasts used—Achievable – Business as Usual ("BAU"), Codes & Standards, and Achievable – High. Though stated broadly in the AEG Market Potential Study, the August 2021 Update, and in Response to PUC-HECO-IR-6, it remains unclear what exactly is included and the reasons as well as sources for the assumptions made. In Response to PUC-HECO-IR-6 which asks to explain in detail what is included, Hawaiian Electric states:
>
>> Business as Usual includes savings from realistic customer adoption of energy efficiency measure through future programs that are similar in nature to existing programs. Codes & Standards includes Federal appliance standards, state standards, and state and local building codes. Achievable High is an achievable

potential that incorporates future non-program interventions such as new codes & standards and market transformation.

The AEG Market Potential Study outlines the types of achievable residential and commercial measures, though the underlying assumptions used to determine "realistic customer adoption" in BAU do not appear to be provided. The AEG Report also states that the BAU "assumes gradual maturation of future interventions which are similar to those in the market today." Some preliminary questions based on these broad statements include, how do historical adoption trends affect the baseline projections? What growth rate is assumed? For Codes & Standards, the Consumer Advocate recommends that a summary, timeline, and corresponding adoption impact of each Federal appliance standard, state standards, and state and local building codes be provided. For Achievable High, the AEG Market Potential Study "assumes adoption ramps up linearly to a maximum limit of 85% participation, which is consistent with previous potential studies as well as other planning guidance in other regions of the country." These referenced studies should be provided along with further explanation and accompanying assumptions for each measure type. For example, is 85% market adoption reasonable to assume across all measure types? In sum, it would be extremely helpful to review detailed bottom-up spreadsheets with formulas intact that calculate the potential savings for each of the scenarios.[22] (footnotes omitted)

Hawaiian Electric Response:

As described in the August Update, page 57, Codes & Standards, Achievable-Business as Usual and Achievable-High were provided to the Companies as separate forecasts by AEG. The Companies did not receive any more granular detail than what is publicly available from the State of Hawaii Market Potential Study.

In response to the Consumer Advocate's comments on the AEG Market Potential Study and its underlying assumptions, the Company reached out to AEG and they have provided the following responses.

- **BAU Case Development and Trend.** The adoption of measures in the BAU case was developed by comparing LoadMAP technical potential to program accomplishments between 2016-2018 and the filed targets for 2019-2020 in the triennial plan to determine a starting percentage of technical potential that reflected current reality on the ground. From this starting point, adoption rates increase by 1% each year, to a maximum of 85%.

[22] Consumer Advocate Comments at 6-8.

(Note: A minimum starting point of 15% was used for measures that were either not in previous programs or had very low participation in the reference data.)

- **Codes & Standards.** As noted on page 28 of the Hawaii 2020 Market Potential Study Final Report, the potential study baseline incorporated federal and state equipment standards that were on the books as of 2019. These standards and their years of effect have been provided in Attachment 2 Hawaii MPS Equipment Codes and Standards. IECC 2015 compliance is assumed for new construction and is implicit in equipment Unit Energy Consumption (UECs) produced by code-compliant building simulations.
  - Reporting the impacts of each equipment code/standard is possible but will require time to gather and subtract out the counterfactual model run from the reference baseline used in the potential study.
  - To report specific energy impacts of the building codes, a counterfactual model set would have to be built that removed the new construction UEC adjustments. This would be a substantial effort.
- **Achievable High 85% Limit.** The upper bound of 85% participation is standard practice for the Northwest Power and Conservation Council (NWPCC) power plans, which cover Idaho, Montana, Oregon, and Washington state (https://www.nwcouncil.org/sites/default/files/2007_13_2.pdf). It is based on a participation study performed by that body which targeted maximum participation under ideal circumstances (all customer costs covered, etc.), and is intended to be inclusive of regional market transformation and new programmatic offerings. It should also be noted, as described on p 35 of the report, that 85% is an end target, not an immediate value applied to first-year potential. Some measures (such as residential lighting) reach this target quickly because they are simple and easy interventions with excellent market traction already, while more costly and invasive measures such as replacing insulation may take 20 years to reach this target.
- **Detailed bottom-up spreadsheets with formulas intact that calculate the potential savings for each of the scenarios.** To be responsive to this request would require AEG to provide our full LoadMAP model. At this time, we do not have Commission approval to provide this model to the Consumer Advocate.

B. Response to Ulupono Comments

As described below the Companies met with Ulupono to discuss the issues raised with respect to the resource cost projections. Through those discussions, as noted in response to Ulupono-1, the Companies have come to an agreement with Ulupono on assumptions to move forward with. The Companies will make those changes and any other changes as necessary in

the next version of the Inputs and Assumptions and associated workbooks, expected following the Commission's decision on the August Update.

The Companies appreciate Ulupono's comments regarding grid services and modeling methods in items Ulupono 10-13. The Companies provide responses herein, but will continue to work with Ulupono and the TAP as it works toward the Grid Needs Assessment Methodology report and next review point, which will include details on the grid services and modeling methods.

1. Item Ulupono-1

> However, after updating these spreadsheets to use NREL ATB 2021 data, we have not been able to exactly reproduce the RESOLVE inputs that Hawaiian Electric published in August 2021, particularly for geothermal power. We were also unable to reproduce the multipliers that Hawaiian Electric reported using to benchmark NREL ATB-based costs to reflect the cost of recent renewable energy projects in Hawaii. Before modeling begins, we recommend that Hawaiian Electric provide copies of all the spreadsheets used for this calculation, including those used for benchmarking, so the process can be reviewed and verified to be correct.[23] (footnote omitted)

Hawaiian Electric Response:

The Companies provided the results of the resource cost forecast proposals as follows:

[23] Ulupono Comments at 4.

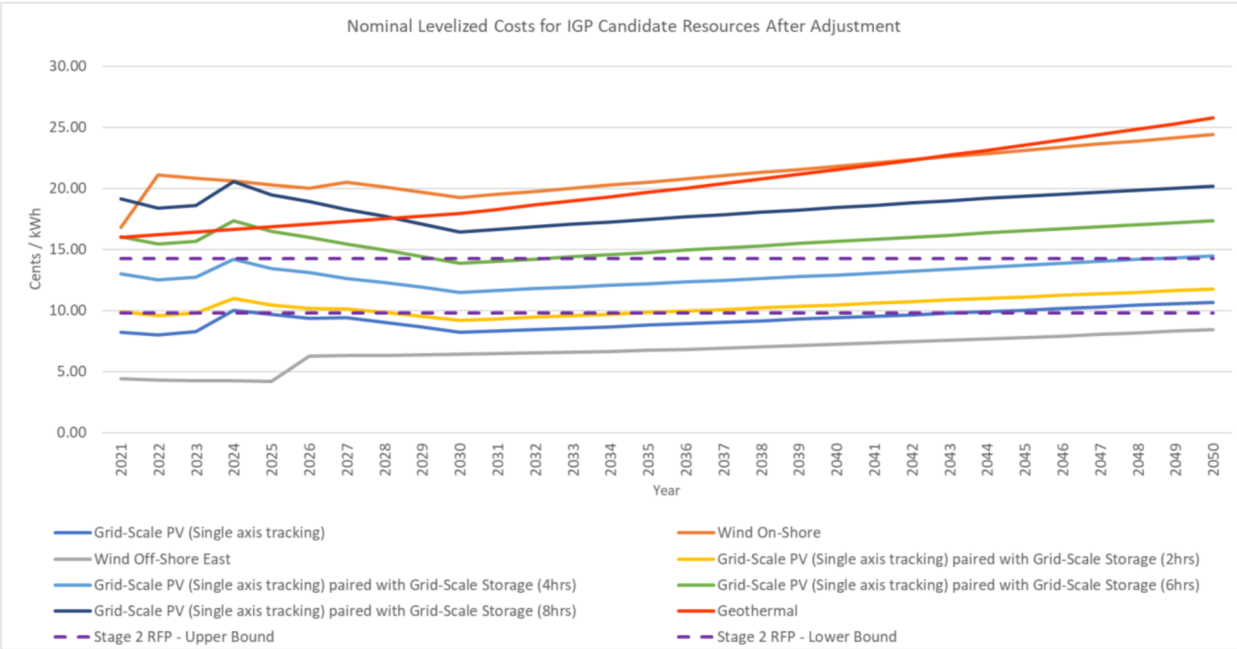

Figure 1: Forecast 1 - LCOE for select resources based on the forecasted resource cost filed on August 2021.

Shown above in Figure 1 is the levelized cost of energy ("LCOE") for select resources based on Forecast 1, which is the forecast that was provided in the August 3, 2021 filing. Based on feedback from Ulupono, the first correction made was for the application of the State ITC to grid-scale PV. The August 3rd filing assumed the State ITC was still available to future grid-scale PV. Ulupono referenced the latest version of the Renewable Energy Technologies Income Tax Credit (RETITC) – HRS § 235-12.5[24] which states that the State ITC for solar energy systems cannot be applied to systems larger than 5 MW if it does not have an approved or pending PPA by the PUC by December 31, 2019. As a result, Forecast 2 was developed which takes Forecast 1 and removes the State ITC for future grid-scale PV. Shown below in Figure 2 is the LCOE for select resources based on Forecast 2.

[24] https://www.capitol.hawaii.gov/hrscurrent/Vol04_Ch0201-0257/HRS0235/HRS_0235-0012_0005.htm

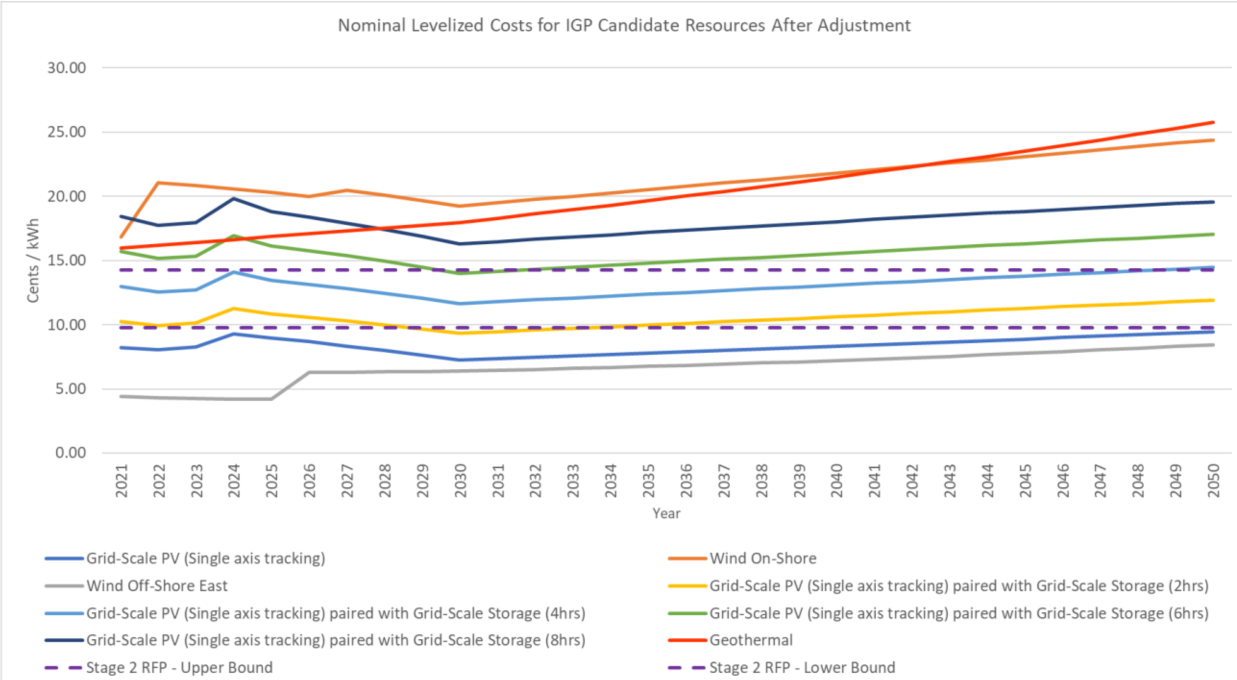

Figure 2: Forecast 2 - LCOE for select resources based on Forecast 1 with the removal of State ITC for Utility PV.

Based on feedback from Progression Energy and Ulupono, the next correction made was to the Federal ITC. Ulupono noted a discrepancy between the Federal ITC being used for grid-scale PV in the August forecast and what is shown on the Database of State Incentives for Renewables & Efficiency ("DSIRE")[25]. After review, the Federal ITC was adjusted to match what is shown on DSIRE.

Progression Energy stated that the Federal ITC assumption should consider the time for construction as part of the safe harbor provisions. The 2021 NREL ATB provides the construction duration for the various resources. The construction duration for solar was one year while the construction duration for onshore wind was two years. This was used to adjust the Federal ITC for these resources. For offshore wind, the construction duration provided by

[25] https://programs.dsireusa.org/system/program/detail/658

NREL's draft O'ahu Offshore Wind Study was 10 years[26]. Forecast 3 was developed which takes Forecast 2 and adjust the Federal ITC for grid-scale PV, onshore wind, and offshore wind. Shown below in Figure 3 is the LCOE for select resources based on Forecast 3.

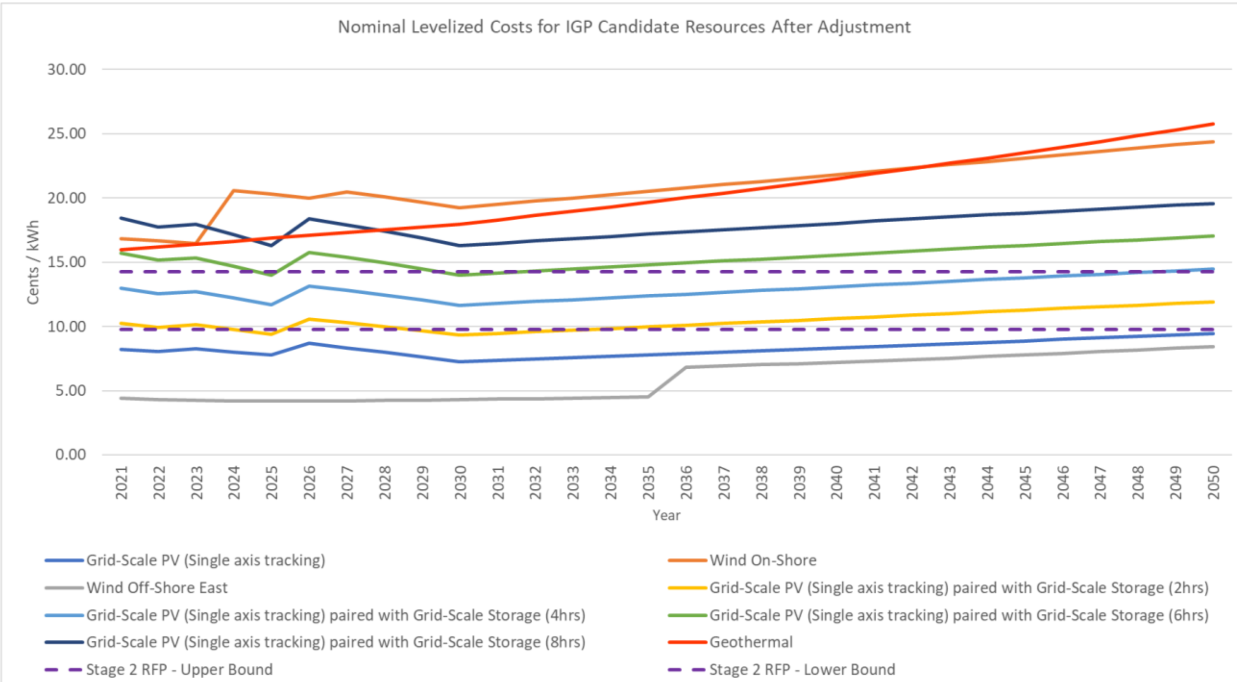

Figure 3: Forecast 3 - LCOE for select resources based on Forecast 2 with the adjustment of the Federal ITC for Utility PV, Onshore Wind, and Offshore Wind.

Ulupono also recommended that for paired PV with BESS, Hawaiian Electric use the cost for Utility-Scale PV-Plus-Battery that was provided in the 2021 ATB forecast rather than the separate costs for standalone PV and standalone BESS. After consideration, Hawaiian Electric incorporated this recommendation. The forecast provided in the 2021 ATB for Utility-Scale PV-Plus-Battery assumed that the paired BESS had a fixed 4-hr duration. To estimate the cost for paired BESS that had 2-, 6-, and 8-hr duration, the cost was scaled proportionately. Forecast 4 started with Forecast 3 and used the Utility-Scale PV-Plus-Battery cost provided in the 2021

[26] https://energy.hawaii.gov/nrel-study

ATB forecast to derive the cost for the paired PV and paired BESS. Shown below in Figure 4 is the resulting LCOE for select resources based on Forecast 4.

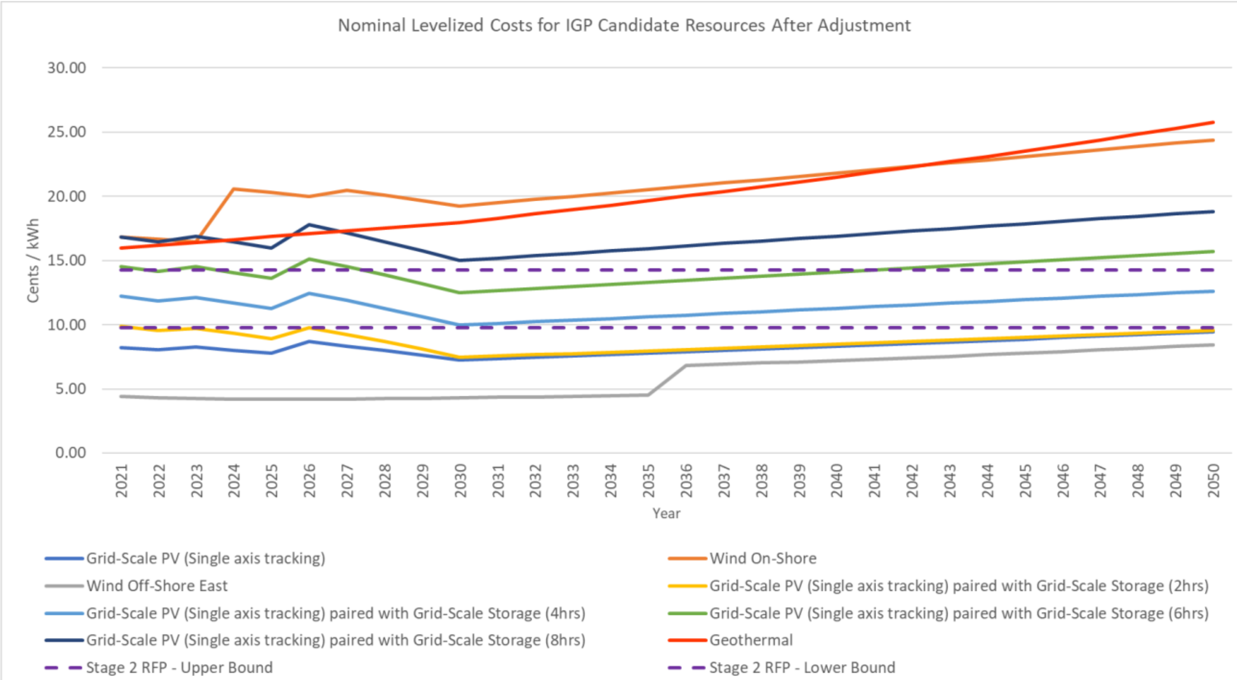

Figure 4: Forecast 4 - LCOE for select resources based on Forecast 3 and incorporating the Utility-Scale PV-Plus-Battery cost provided in the 2021 ATB forecast to derive the cost for the paired PV and paired BESS.

Ulupono also recommended benchmarking to projects that have either 20- or 25-year PPAs. To do this, Ulupono suggested converting the annual lump sum payments to an NPV, and use that as a proxy capital cost. Hawaiian Electric incorporated this recommendation and used this NPV method to benchmark the resource cost to recent 20- or 25-year PPAs. Forecast 5 starts with Forecast 4 and incorporates the NPV benchmark methodology to benchmark the cost to recent 20- or 25-year PPAs. Shown below in Figure 5 is the resulting LCOE for select resources based on Forecast 5.

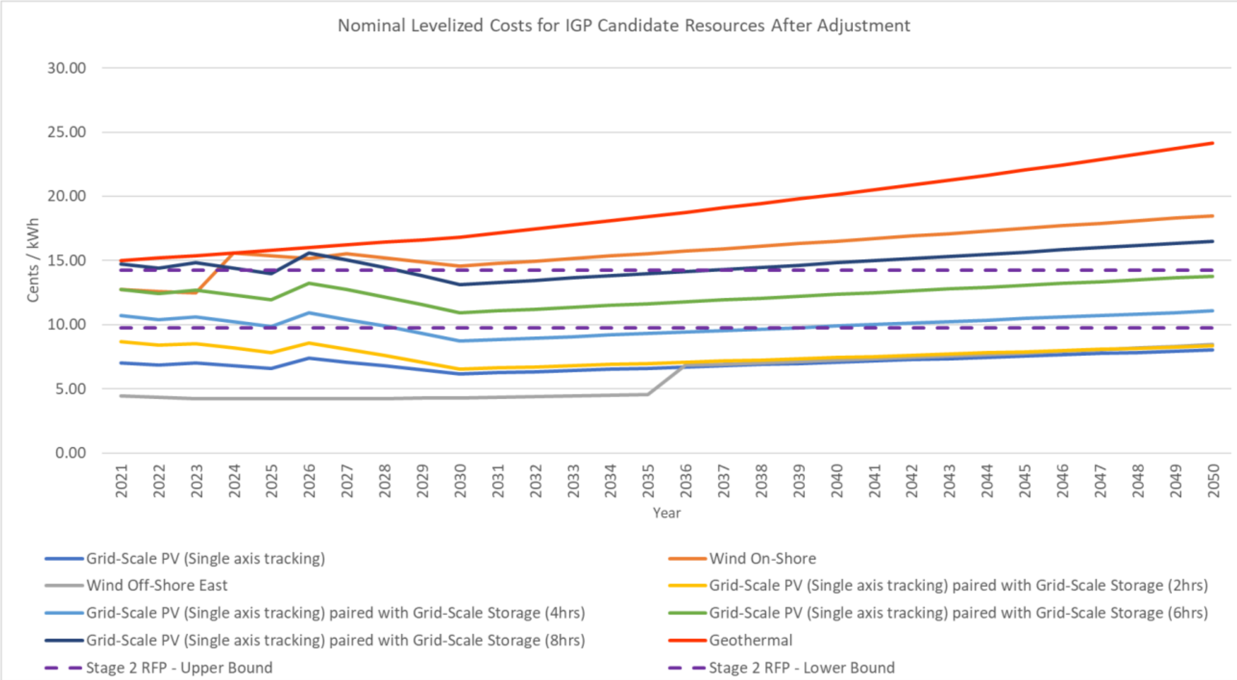

Figure 5: Forecast 5 - LCOE for select resources based on Forecast 4 and using the NPV benchmark methodology to benchmark the cost to recent 20- or 25-year PPAs.

Ulupono had concerns about the cost spread between the onshore wind cost and the offshore wind cost. Two adjustments were made to the forecast to help reduce the spread. The first change was recommended by Ulupono. Ulupono recommended that Hawaiian Electric use the actual size of existing projects when calculating the cost for benchmarking, rather than a standard 1 MW size. Since the State ITC has a cap, the size being used impacts whether the limit on the State ITC would be reached. If the limit is reached, this would impact the tax savings and resulting cost, and consequently, the scaling factor used to benchmark the resource cost. Since there is no longer a State ITC for grid-scale PV and geothermal does not have a cap on its ITC, this recommendation would only impact the benchmarking for onshore wind, which is scaled to Na Pua Makani. After consideration, this recommendation was incorporated.

Hawaiian Electric also reached out to NREL to discuss how they made the offshore wind cost specific to Hawaiʻi in their draft Oʻahu study. NREL noted adjustments made to the capital and related transportation costs but labor adjustments were not identified. Because the EIA location adjustment factor accounts for labor wage and productivity differences, the Company decided to include the EIA location adjustment factor that was used for onshore wind.   Forecast 6 was developed which takes Forecast 5 and uses the actual size of Na Pua Makani to calculate the scaling factor to adjust the cost for onshore wind, as well as apply the EIA location adjustment factor to offshore wind. Shown below in Figure 6 is the LCOE for select resources based on Forecast 6.

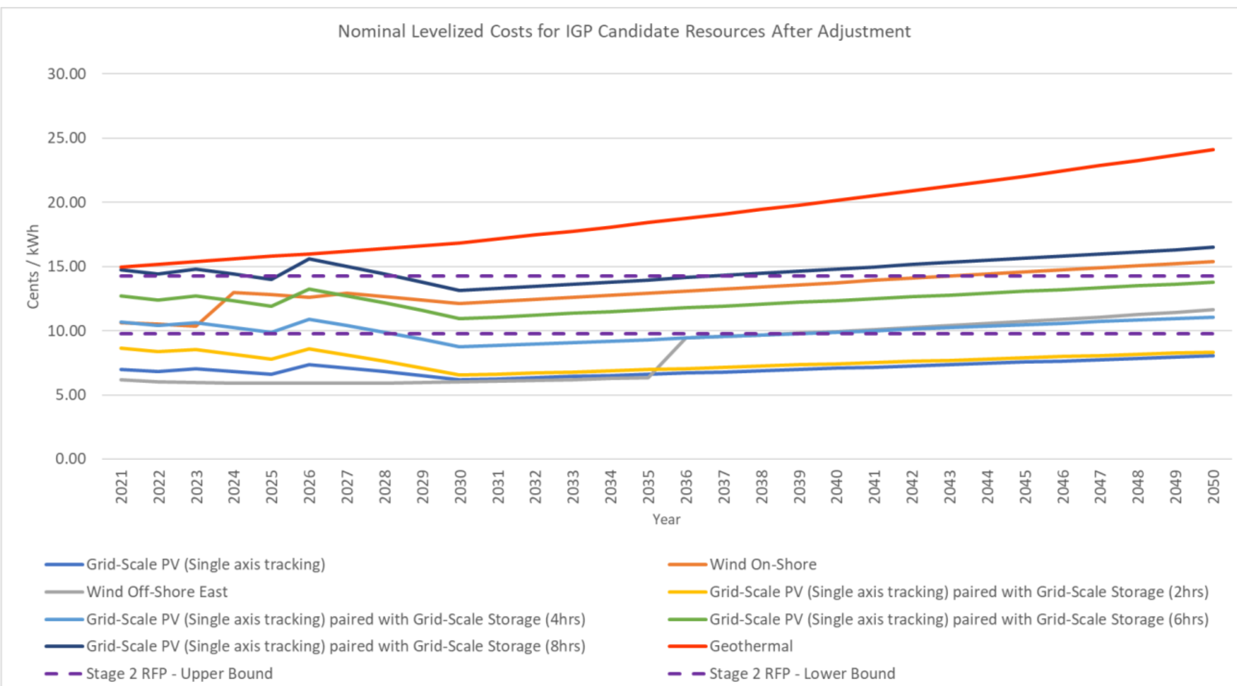

Figure 6: Forecast 6 - LCOE for select resources based on Forecast 5 and using the actual size of NPM to benchmark the Onshore Wind cost and use the EIA locational adjustment factor for Offshore Wind.

Ulupono also recommended Hawaiian Electric use existing projects on each island to benchmark the cost of projects on that island, rather than using projects across all islands. This may be possible to do for paired PV and paired BESS due to the number of recent projects from the Stage 1 and Stage 2 RFPs on O‘ahu, Maui, and Hawai‘i Island. As noted in Ulupono-3, however, it is not clear that projects cost more on Maui and Hawai‘i Island relative to O‘ahu, which appears to be Ulupono’s main driver to separately benchmark by island. Nevertheless, Hawaiian Electric still tested this recommendation to determine its impact. For resources other than paired PV and paired BESS, however, there are not enough recent projects to benchmark the islands separately, and using older projects may not provide an accurate target cost to benchmark against.

Forecast 6HE starts with Forecast 6 and incorporates the NPV benchmark methodology to benchmark the cost of paired PV and paired BESS to recent 20- or 25-year PPAs on O‘ahu. Similarly, Forecast 6ME and Forecast 6HEL would use PPAs on Maui and Hawai‘i Island, respectively. Shown below in *Figure 7*, *Figure 8*, and *Figure 9***Error! Reference source not found.** are the resulting LCOE for select resources based on Forecast 6HE, Forecast 6ME, and Forecast 6HEL, respectively.

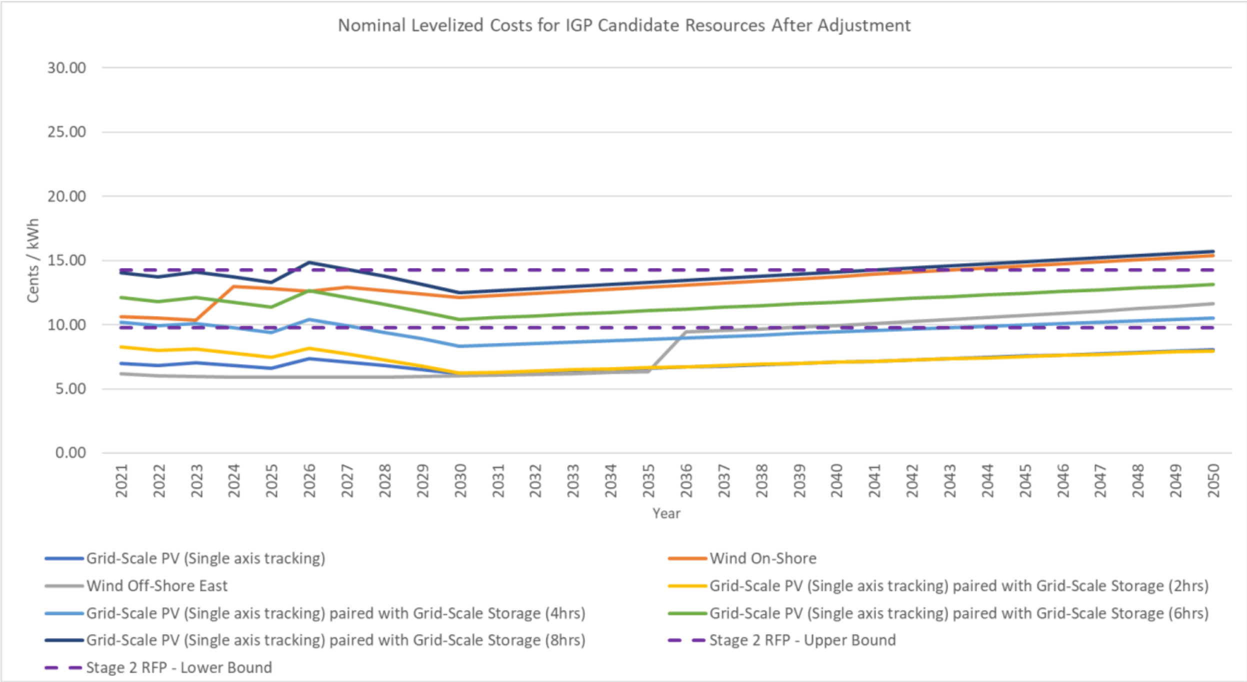

Figure 7: Forecast 6HE - LCOE for select resources based on Forecast 6 but benchmarking for paired PV and paired BESS based on 20- and 25-year PPAs on O'ahu only.

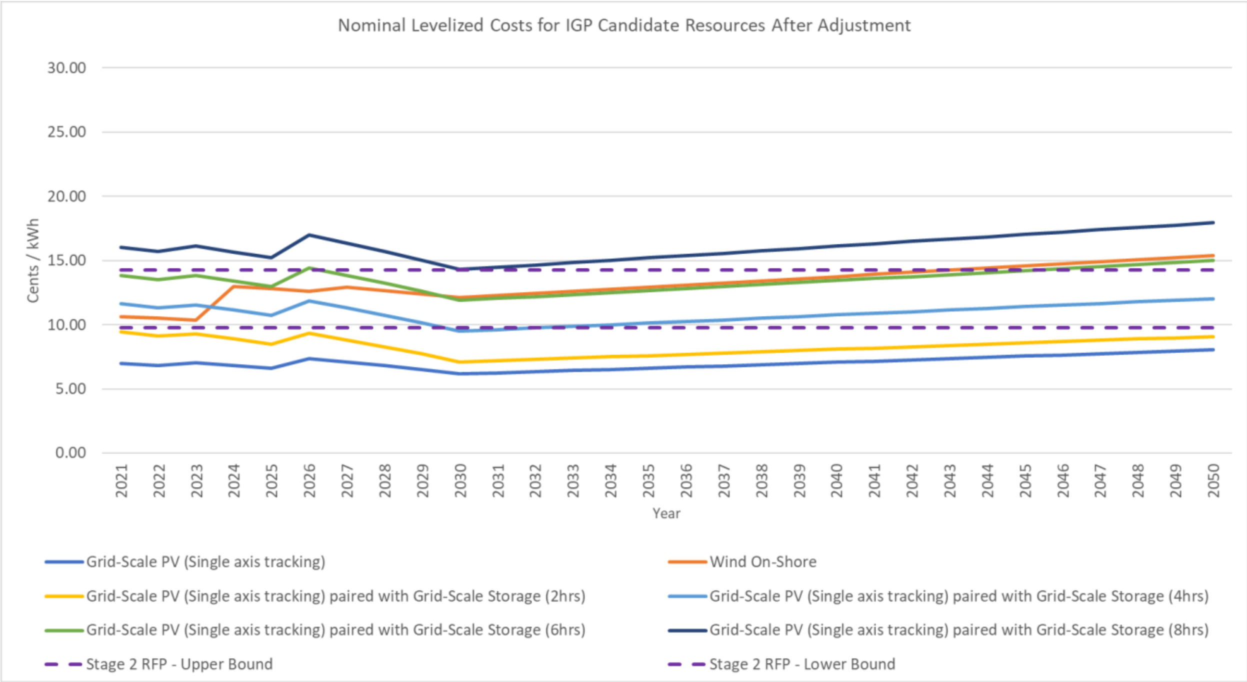

Figure 8: Forecast 6ME - LCOE for select resources based on Forecast 6 but benchmarking for paired PV and paired BESS based on 20- and 25-year PPAs on Maui only.

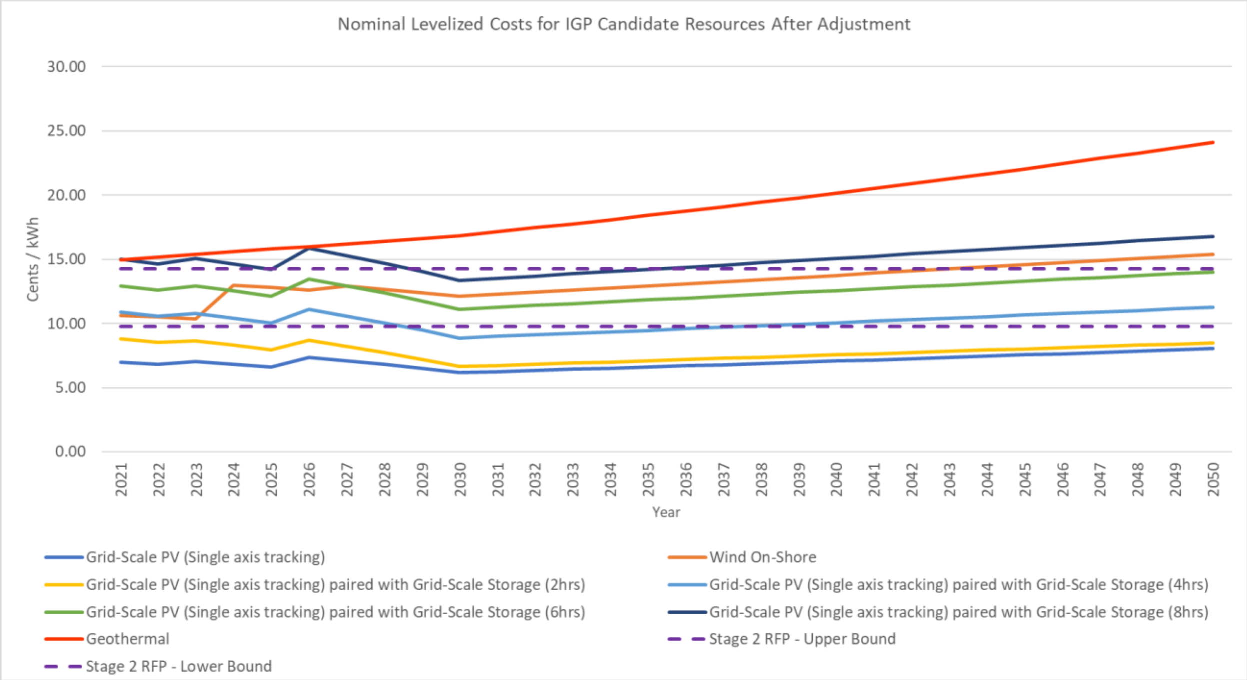

Figure 9: Forecast 6HEL - LCOE for select resources based on Forecast 6 but benchmarking for paired PV and paired BESS based on 20- and 25-year PPAs on Hawai'i Island only.

Based on *Figure 7* through *Figure 9*, it does not appear that benchmarking paired PV and paired BESS to recent projects on the individual islands had a material impact on the cost.

Finally, Ulupono also recommended that the benchmark for onshore wind be removed. Hawaiian Electric tested this recommendation as well. To ensure that all resources were treated similarly, however, the benchmark was removed from all resources. Forecast 7 was developed which takes Forecast 6 and removes the benchmarking. Shown below in Figure 10 is the LCOE for select resources based on Forecast 7.

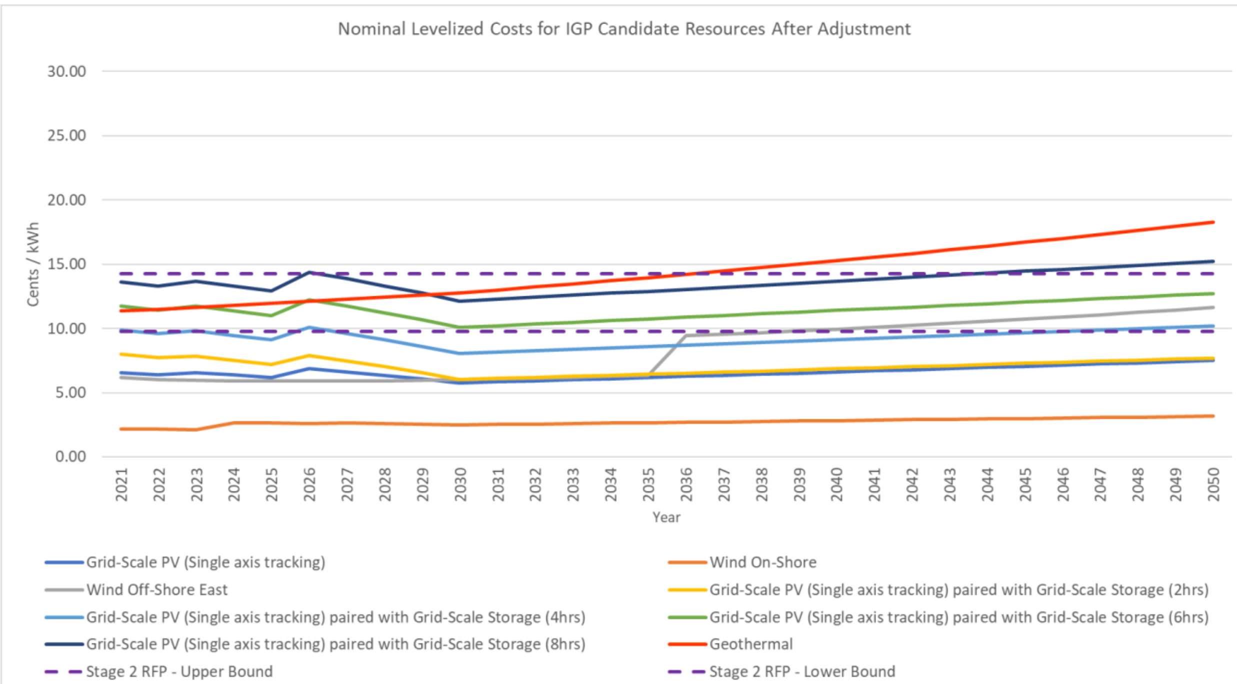

Figure 10: Forecast 7 - LCOE for select resources based on Forecast 6 and removing the benchmark for all resources.

Hawaiian Electric presented the above results to representatives from Ulupono on September 17, 2021. After some discussion, both parties agreed that the best path forward at this time is to use Forecast 7 because it uses public data provided by NREL and EIA and can be transparently traced from the source data to the forecast. The consensus was to not use a

benchmark for all projects because there was a limited dataset to develop a representative benchmark, particularly for onshore wind given that Na Pua Makani is the only recent project for that resource category and at a smaller 24 MW capacity compared to other existing onshore wind projects. Further, the paired PV+BESS resource cost forecast was in line with recent Stage 2 RFP project costs before any benchmark was applied and was the resource category that had the most substantial dataset; thus, validating the NREL ATB costs. Because the onshore wind benchmark was deemed to be misleading and paired PV+BESS did not require a significant benchmark because the forecast was already aligned, the benchmarking was removed entirely to treat all resource categories equally. Since Forecast 7 removes the benchmarking, there is no longer a need for a separate forecast for each of the main islands.

As stated in response to CA-2, the modeling framework provides flexibility to make adjustments or iterations. Once the base case is run with the proposed Forecast 7, the model selections can be reviewed with stakeholders and sensitivities run if certain resource builds are overly optimistic or likely to encounter community opposition (*i.e.*, a no wind case). To this end, both Ulupono and the Company discussed that the competitive procurement (solution sourcing) is the appropriate place to sort out any perceived or real technology and price mismatches. The grid needs assessment phase should be based on best available data and also send a signal to the market what the most reasonable technology costs are on a forward looking basis, not necessarily benchmarked to technology prices in the past.

2. Item Ulupono-2

> We recommend that Hawaiian Electric use the actual size of existing projects when calculating the equivalent NREL ATB cost for these prior to benchmarking, rather than a standard 1 MW size. This will ensure that the State tax credits are calculated correctly for

> benchmarking. The expected size of proposed projects should then be used in the tax credit calculations when calculating the cost of the proposed projects.[27]

Hawaiian Electric Response:

The 1,000 kW size is based on the administrative rules for the RETITC for wind. See https://files.hawaii.gov/tax/legal/tir/tir12-01.pdf for the definition for total output capacity. For commercial properties, this is defined as at least 1,000 kW per system. This assumption will be maintained for wind, in the calculation of the ITC in the resource cost.

The latest amendment to HRS § 235-12.5 removes the State ITC for PV for projects requiring an approved power purchase agreement at or above 5 MW. PV costs will be updated to remove the State ITC.

3. Item Ulupono-3

> We recommend that Hawaiian Electric use existing projects on each island to benchmark the cost of projects for the same island. For example, we do not recommend the use of Maui projects to benchmark costs for Oahu projects, as is done in the July 2021 spreadsheets. Pooling projects across islands tends to overstate the cost of solar on Oahu and understate it on other islands, where recent projects have been more expensive. This could result in poor selection of resources on all islands. For example, in the July 2021 spreadsheets, using only Oahu solar projects gives a benchmark multiplier of 82% (i.e., recent projects cost 82% of the amount calculated from the NREL ATB), but using projects from all islands produces a benchmark multiplier of 93%, raising the Oahu solar price forecast by 14% and making Oahu solar look less attractive than it is relative to other options. Conversely, using Oahu prices to benchmark Maui projects makes solar project on Maui look more attractive than it should. We are also concerned that the benchmark multiplier reported in the August IGP Update was 106%, which is significantly above the multiplier that Hawaiian Electric showed in July 2021 . This change is not explained in the August IGP Update.[28]

Hawaiian Electric Response:

As noted in the Companies' response to Ulupono-1, the benchmarking discussion is now moot. However, the Companies provide the following response to this item. It is not clear that projects

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[27] Ulupono Comments at 4.

[28] *Id*. at 4-5.

cost more on other islands compared to O‘ahu. There are a limited number of PV+storage projects that can serve as data points to benchmark against. In recent news releases, unit prices for projects on other islands were less than O‘ahu, contrary to what Ulupono has stated above (see https://www.hawaiianelectric.com/new-renewable-projects-submitted-to-regulators-will-produce-lower-cost-electricity-advance-clean-energy). Since the non-benchmarked NREL ATB data confirmed to be within in the range of the actual Stage 2 solar+storage projects, the Companies believe that benchmarking is no longer needed (see, Figure 10, Forecast 7).

4. Item Ulupono-4

> We recommend that Hawaiian Electric use benchmarks based on projects that have either a 20 or 25 year power purchase agreement ("PPA"), rather than just using the ones with 25 year PPAs, as reported in July 2021. One way to do this would be to convert the PPA cost streams for each project into a net present value ("NPV") in the year of construction, which can then be used as a proxy capital cost. This method will also make it possible to benchmark battery energy storage projects that have variable payment streams. This change is likely to broaden the pool of projects that are included in the benchmark, but we do not expect it to significantly alter the benchmark cost.[29]

Hawaiian Electric Response:

See response to Ulupono-1. The benchmarking was redone on a net present value basis to include both 20 and 25 year PPAs to further increase the data points used in the benchmarking.

5. Item Ulupono-5

> We recommend that for paired solar/battery projects, Hawaiian Electric should use the costs from the NREL ATB 2021 "Utility-Scale PV-Plus-Battery" worksheet if possible, instead of the separate "Solar - Utility PV" and "Solar - Utility PV" worksheets. This is not expected to have a large effect on the resource forecasts, because the resulting values will then be benchmarked against recent projects.[30]

[29] *Id.* at 5.
[30] *Id.*

Hawaiian Electric Response:

See response to Ulupono-1. The resource costs for paired projects was revised to use the Utility-Scale PV-Plus-Battery worksheet from the NREL ATB published in 2021.

6. Item Ulupono-6

> The benchmark calculations appear to assume that recently contracted solar projects used for benchmarking will receive the 25% State tax credits, and that these tax credits will drop to 15% for new projects built in 2027 and later. This causes a roughly 13% step up in the cost of grid-scale solar projects in 2027 and later. However, it appears that State tax credits for solar projects will actually be 0% for all projects contracted in 2020 or later3 (i.e., there are no State tax credits embedded in the cost of the benchmark projects), so this step-up will not actually occur. We recommend that Hawaiian Electric revise the schedule of state tax credits to reflect current law.
>
> The August IGP Update shows 10% federal tax credits for solar projects started in 2024 or 2025, but the DSIREUSA database4 shows 22% credits in these years. We recommend that Hawaiian Electric verify that they are using the correct schedule of federal tax credits before running the model.[31] (footnote omitted)

Hawaiian Electric Response:

See response to Ulupono-1. The Federal ITC was updated for PV, consistent with the rate shown on the DSIREUSA database. The State ITC was removed for PV to reflect current law.

7. Item Ulupono-7

> For onshore wind, Hawaiian Electric used a single project, Na Pua Makani, to perform cost benchmarking. This is a small sample, including a single, small project, which resulted in a very high benchmark multiplier: 772%. A single, small project is not enough evidence to make a general claim that future wind projects in Hawaii will cost nearly 8 times more than similar projects on the mainland (on top of the EIA location-specific multiplier that is also included in the forecast). Conversely, for offshore wind, the August IGP Update uses costs for offshore wind directly from a Hawaii-specific study. That study reported costs 20- 28% lower than the equivalent NREL ATB 2021 values, and Hawaiian Electric used those costs without any benchmarking. This produces the surprising assumption that *offshore wind will cost 3-5 times less than onshore wind over the next 30 years*, and will also cost less than grid-scale solar in some early years. We are not aware of any study that has found floating offshore wind projects could be developed and installed at a lower cost than onshore wind in the same region. We recommend that

[31] *Id*. at 5-6.

> the cost forecasting be changed to avoid these inconsistent assumptions, which seem to arise from inconsistencies in the data sources and small or missing benchmark datasets. One option would be simply to use the NREL ATB costs for onshore and/or offshore wind power, with EIA location adjustments but little or no benchmarking to existing projects. Another option would be to examine the actual costs of developing and installing offshore floating wind farms compared to the actual costs of developing and installing onshore wind farms, preferably in the same country to ensure substantially complete comparability.[32]

Hawaiian Electric Response:

See response to Ulupono-1. The EIA location adjustment factor for wind was incorporated into the offshore wind resource cost. Although the Oʻahu offshore wind study did consider Hawaiʻi specific factors such as identification of ports and grid connection infrastructure, customized export cable sizes, hurricane resilience, and transportation cost premium, labor and productivity differences were not considered. Labor and productivity differences are accounted for in the EIA location adjustment factor.

The Companies agree that one project may not be enough evidence to benchmark all future projects for a particular resource type. If benchmarking is removed for one technology, all technologies should be treated similarly and all resource costs be forecasted without benchmarking. As discussed in response to Ulupono-1, the Companies and Ulupono have reached agreement to remove all benchmarking.

8. Item Ulupono-8

> **Resource Potential.** Ulupono supports Hawaiian Electric 's proposal to use the PV-Alt-1 and Wind-Alt-I (No Wind Speed Threshold) resource assessments from the "Assessment of Wind and Photovoltaic Technical Potential for the Hawaiian Electric Company" report by NREL (7/31/21 update). These address most of our concerns about the risk of underestimating available renewable resources and consequently adopting a plan with less than the optimal amount of renewable power. We recommend additional work in the future to assess more exactly which military and non-military lands would be suitable for wind and solar development. If future work shows that too little land is available to meet the islands' needs for solar power, then Hawaiian Electric should consider power exports

[32] *Id*. at 6.

> from customer-sited solar systems as another source of renewable power, which is likely to be a cheaper and more self-sufficient than thermal power plants.[33]

Hawaiian Electric Response:

Ulupono supports the resource potential assumptions. In regards to ,ilitary lands, the Company suggests that the potential for wind and solar projects to be developed on military lands be placed in the IGP parking lot to consider in future planning cycles. As noted in the August Update, Federal contracting rules for highest and best use of its properties introduce additional complexity and cost when determining the available Department of Defense lands for renewable energy development. Additionally, a dispatchable DER aggregator resource will be made available in the RESOLVE models for selection to represent customer sited solar systems in addition to other grid-scale options.

9. Item Ulupono-9

> **Thermal Generating Unit Removal from Service Schedules.** Ulupono does not take a position on the proposed retirement schedules for existing thermal generation units. These appear acceptable, but we would prefer that retirement dates be selected by an optimization method (e.g., RESOLVE), based on the cost of continuing to keep these units in service and the cost of alternative power sources.[34]

Hawaiian Electric Response:

Also see the Companies response to JP-5. The unit removal from service schedules are intended to be starting points for existing unit retirements. Actual retirement decisions are operational decisions that will be made at a later date based on a number of factors, including whether sufficient resources have been acquired and are in service, ancillary services provided by these generators have been sufficiently replaced, and after consideration for reliability and resilience factors, among others. However, as part of the grid needs assessment and solution

[33] *Id.* at 6-7.
[34] *Id.* at 7.

sourcing process, the Company may identify additional opportunities to accelerate retirement of fossil fuel units.

10. Item Ulupono-10

> **Inertia Requirement.** Ulupono supports Hawaiian Electric's decision to remove the inertia requirement from the RESOLVE modeling (August IGP Update at 17), since it appears likely that the system will have enough inertia without this requirement. Alternatively, we would support inclusion of an inertia requirement in the RESOLVE modeling, provided that it allows for batteries and curtailed renewable power sources to provide virtual inertia to assist in meeting this requirement.
>
> We further recommend that Hawaiian Electric assume that virtual inertia and other grid-forming capabilities can be provided by batteries and curtailed renewable sources when running PLEXOS or other software to assess the adequacy of Hawaiian Electric's plans. Hawaiian Electric has expressed reluctance to include virtual inertia in their modeling because it is at a pre-commercial stage. However, they have simultaneously required provision of virtual inertia from the new Kapolei Energy Storage facility. It is incongruous to require this service from plants coming online today, while simultaneously assuming that it will not be available from planned plants until after 2050. The likely effect of this approach that assumes virtual inertia will not be available will cause the model to choose thermal plants or synchronous condensers, thus exacerbating this bias.
>
> Imposing a requirement for inertia service while assuming that inverters cannot provide this service would artificially bias the model in favor of spinning machines-thermal plants or synchronous condensers. Hawaiian Electric has shown that relaxing this requirement has a small effect on total system costs. However, in the same place, they show that the inertia requirement has a significant effect on system design, raising investments in biomass capacity by 159 MW (38%) and reducing investment in grid-scale solar by 575 **MW** (27%). Further, Hawaiian Electric' have proposed to use faulty ERM/HDC assumptions (discussed below) that would also force excess thermal capacity into the plan. Simultaneously using faulty assumptions about both inertia and ERM/HDC could drive excess thermal capacity into the plan in a "belt and suspenders" manner, where either assumption will drive investment in thermal capacity on its own, even if the other one is corrected. Both assumptions must be corrected to get an optimal plan.[35] (footnotes omitted)
>
> **Hawaiian Electric Response**:

[35] *Id*. at 7-8.

Ulupono supports the decision to remove inertia and FFR from RESOLVE modeling. Regarding grid-forming inverters, as described in the IGP modeling framework filed in the Updated Timeline and Stakeholder Engagement Plan on June 18, 2021 and discussed with stakeholders in the STWG on July 14, 2021, the inertia and FFR requirements will be removed from the capacity expansion and production simulation modeling and instead be assessed as part of the network stability simulations at the end of the process. If the stability criteria is not met, the prior production simulations or capacity expansion modeling will be adjusted to address any grid service shortfalls. The Company will evaluate total system FFR and inertia needs leveraging the capabilities of grid forming inverters similar to the Island-Wide PSCAD study shared with the STWG on June 30, 2021 (see https://www.hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning/island-wide-pscad-study-meeting-june-30-2021). These changes ensure that any selection of thermal units by the RESOLVE model are not due to needing to meet an inertia or FFR requirement.

11. Item Ulupono-11

> **Energy Reserve Margin and Hourly Dependable Capacity.** In March 2021 , Hawaiian Electric proposed to apply a predefined Energy Reserve Margin ("ERM") in the RESOLVE modeling, with each generating resource receiving a credit toward the ERM based on its Hourly Dependable Capacity ('HDC'). 8 This is not discussed further in the August IGP Update. However, Hawaiian Electric noted in the September 7, 2021 meeting9 that reviewed the August IGP Update that they plan to try several levels of ERM to identify the minimum level that produces a reliable power system. They also proposed to replace the HDC with production profiles for each sample day. We support both of these changes, but with some recommendations for improvement. Below, we present our concerns about the previous method, as described in the March 2021 Report, and some recommended changes to the proposed methods.
> In the March 2021 report, Hawaiian Electric proposed an ERM equal to 30% of system load each hour on Oahu, Hawaii and Maui, and 60% of system load on Molokai and Lanai. Hawaiian Electric did not put forward a clear rationale for these levels, and the targets appeared to be based on historical rules of thumb and/or studies based on historical design of the power system. We support Hawaiian Electric's proposal to abandon this approach and instead test several targets, then evaluate the reliability of the proposed plan with each one, and adopt the lowest ERM target that produces adequate

> reliability. This is a straightforward approach that will avoid the risk of overbuilding based on arbitrary targets.
>
> However we recommend a few improvements to this process:
>
> a. It would probably be helpful to include N-1 outage criteria in RESOLVE itself, so the model can optimize the selection of large vs. small power plants.
> b. The September 7, 2021 proposal uses 10% steps in the ERM. Once the modeling is underway, it would be useful to evaluate finer steps between the maximum inadequate ERM and the minimum adequate ERM, to more closely identify the correct level.
> c. Hawaiian Electric reported in the September 7, 2021, meeting that they do not plan to include demand response in the ERM calculation. We recommend that demand response (and all other resources) be included in the ERM calculation in the same way that they are included in the day-today load balancing (more on this below).[36] (footnotes omitted)

Hawaiian Electric Response:

It is not clear what is meant by an N-1 outage criteria in RESOLVE. RESOLVE does not consider maintenance or forced outages as part of the capacity expansion modeling. The Company will consult with the TAP once the Company has completed its proposed ERM analysis. Defining adequate reliability could require a high degree of engineering judgement, depending on the intended operating situation to be mitigated. As noted by the TAP in its June 1, 2021 Grid Services and Planning Criteria Feedback at pages 5-6:

> Several times was emphasized by TAP that reliability is critical and "when we think about reliability, we do not want to be short." This may require prioritizing the near-term over the long-term - because in the near-term we're not able to change things as much. There is a need to think about this issue as "minimums," that are required and then looking at the costs of the alternatives for meeting the minimums. Utilities don't want to get caught short on reliability. While the TAP agreed that there can be advantages to going long and growing into it, it was also pointed out that the frame for utilization of these resources must be carefully considered. <u>This is another area, requiring 'engineering judgement', not just models.</u> (emphasis added)

Further, the effects of climate change on weather coupled with the inherent variability that already exists with wind and solar production must be able to accommodate this uncertainty

[36] *Id*. at 8-9.

to provide adequate reliability. Demand response programs are currently being modeled as a supply side resource so they are taken into account as part of the ERM modeling in RESOLVE.

12. Item Ulupono-12

> Within the ERM framework, we are opposed to Hawaiian Electric's earlier proposal to calculate HDC factors for each resource. The HDC framework is an outdated approach that is not suitable for power systems with large shares of renewable power, storage and demand-side flexibility. The HDC approach attempts to assign a fixed "capacity" value to each resource, when in fact generation adequacy arises from the full portfolio of resources and cannot be reflected by a single "capacity" metric. The contribution of an additional solar project to generation adequacy varies depending on how much other solar, wind, storage or demand response is implemented at the same time. It is simply not possible to assign a meaningful HDC to each resource. A key strength of Switch, RESOLVE or other models in this family is that they consider the full time-series of production or behavior available from each resource, and select a portfolio that will provide a reliable supply of power under all conditions. 10 HDC does not aid in this analysis, and instead biases the model in favor of traditional, "firm" assets.
>
> Put another way, the contribution of each resource to generation adequacy each hour is simply the amount of power that it is able to produce in that hour. So the capacity counted toward the ERM requirements during each sample hour should be equal to the production potential during that hour, as already represented in RESOLVE. The HDC approach replaces the useful information on time-varying availability of each resource with a constant, arbitrary value based on statistical analysis of the resource. This understates the usefulness of each resource at the times when it is actually available (e.g., solar on sunny days) and overstates its usefulness at times when it is not available (e.g., solar on cloudy days).
>
> Ulupono is also opposed to the method that Hawaiian Electric proposed for calculating HDC. In the March 2021 Report, Hawaiian Electric proposed to use the mean production from each resource, minus N standard deviations of the hourly production. If output - from the resource followed a Gaussian distribution, than using N=3 would produce an estimate of the 99.7% reliable output. However, wind and solar output do not follow a Gaussian distribution, so this method would not actually identify the expected percentile of output. Further, the 99.7% reliable output from a solar array or wind farm is not a useful statistic for capacity planning, as discussed in the previous paragraphs.
>
> Instead of using the HDC approach, we recommend that the ERM be modeled in RESOLVE by adding a collection of "ERM" sample days with higher than normal loads, which the model is free to serve using all resources at its disposal. Specifically, RESOLVE should include a collection of normal sample days that reflect the full range of weather that may be experienced (this can include normal days as well as the most difficult weather day or days that the islands have experienced, with appropriate weights; this should be similar to the current sampling method for RESOLVE). Then one or more

> "ERM" sample days should be added, with low or 0% chance of occurring. (For days assigned a 0% probability, RESOLVE must select a plan that could serve loads on those days, but it does not work hard to minimize fuel costs on those days because they have negligible likelihood of occurring. A 0% probability is appropriate for these days because they are not expected to actually occur; they are just used to drive the system to build extra capacity.) On the ERM days, loads should be equal to the normal level on a corresponding historical date plus the ERM percentage (one simple approach would be to create ERM days that are based directly on the standard sample days, but with higher loads). When RESOLVE is run in this way, it will need to select a portfolio that can meet loads on both the standard and ERM days. However, it is free to apply all available resources to the ERM target, including renewables, storage, demand-response and thermal plants. This approach will force RESOLVE to design a power system that *could* meet the extra-high loads on ERM days, but which is also optimized primarily for the conditions on the standard sample days. 11 In this way, the ERM calculations will choose the cheapest portfolio of resources to meet normal loads, while also including additional capacity to improve generation adequacy.[37] (footnotes omitted)

Hawaiian Electric Response:

We believe that HDCs are appropriate to characterize the reliable capacity from variable renewable resources for long-term capacity expansion modeling. The HDC can serve as a reasonable assessment of reliable variable renewable capacity because the most difficult historical weather days may not represent the renewable energy generating potential on the most difficult weather days in the future and can help to ensure adequate capacity is available to serve load because all possible weather would be difficult to explicitly model.

Ulupono's comments on this topic are focused on the evaluation of all aspects of long-term planning (*i.e.*, resource addition optimizations, reliability, operations, etc.) within a single model like RESOLVE or SWITCH. RESOLVE and similar models do not consider the full time series of resource production due to the model's convention to model representative days that are then weighted to extrapolate to full years. The intent of the ERM concept is to consider the full hourly time series for each year of the planning horizon. An hourly production simulation model

[37] *Id*. at 9-11.

like PLEXOS that can consider each hour of each year of the planning horizon would be better suited to assess reliability. This issue also includes planning considerations that are subject to interpretation, such as, developing a resource plan that is able to provide a reliable supply of power under all possible conditions and defining generation adequacy.

Further, reliability analyses are better suited for a production simulation model like PLEXOS that can consider the full hourly time series for each year of the planning horizon. The use of different modeling tools for different purposes was discussed at the June 4 Technical Conference as part of the modeling framework that was recommended by the TAP in its June 1, 2021 Grid Services and Planning Criteria Feedback at pages 3-6. The modeling framework will ensure that the concerns raised by Ulupono are evaluated. For example, the resource adequacy step in the modeling framework will determine whether there is unserved energy based on the RESOLVE resource plan, and whether capacity was over or underbuilt when assessing the ERM level for a given plan.

13. Item Ulupono-13

> **Regulating reserve margin requirements.** In March 2021 , Hawaiian Electric gave a detailed proposal for calculation of the required reserve margin for wind and solar power.12 We generally support the proposed methodology for setting the reserve margin. The proposed approach is likely to be somewhat conservative, since it sets margins separately for wind power, solar power and load. In reality, variations in each of these will often partially cancel each other. However, this is a computationally simple method and works well even if one source of variability (e.g., solar) dominates the power system. Note that in this approach there is no need to formally include any "ERM" components in RESOLVE; difficult conditions are modeled just by adding difficult ERM days.
>
> However, we recommend a few changes to the proposed methodology:
>
> a. While charging, batteries should be able to provide up-reserves equal to the amount of charging plus the maximum potential discharge (e.g., if a 100 MW battery is currently charging at a rate of 50 MW, it should be able to provide 150 MW of up reserves by stopping charging and beginning discharging). It is not clear if this is already the case in the RESOLVE modeling.

b. The proposed methodology sets a reserve requirement equal to 3 standard deviations in the variability of each resource. It is not clear how this level was chosen, but it appears likely that it was designed to achieve 99.7% reliability. However, the 99.7th percentile will only be 3 standard deviations from the mean if variability follows a Gaussian distribution. This is probably not the case for wind and solar production. We recommend that Hawaiian Electric simply find the desired percentile directly from their data, rather than using an approach based on standard deviations. Alternatively, they could identify the actual probability distribution of wind and solar variations and use the appropriate number of standard deviations for that particular distribution.
c. Reserve requirements should be capped at the lesser of the renewable energy output or load. It is not clear whether this is currently done in RESOLVE. There is no need to provide 800 **MW** of backup for solar during hours when it is only expected to produce 600 MW. Similarly, it is surprising to see peak up-reserve requirements of 1721 MW for Oahu in 2045, when the power system is forecast to have a peak demand of 1493 **MW15** (although it is possible that this occurs during intensive battery charging, which simultaneously provides the needed up-reserves, as noted in Section 7.a above).
d. Related to the previous point, we recommend that Hawaiian Electric investigate times when regulating reserve targets are unusually high, to verify that this reflects true uncertainty in the resource, rather than a data analysis error, outlier in the input data, or missing assumption (e.g., no need for regulating reserves in excess of the expected output from the resource).[38] (footnotes omitted)

Hawaiian Electric Response:

The Companies make the following clarifications with respect to the recommendations made by Ulupono. RESOLVE and PLEXOS do account for charging load plus maximum potential discharge in the determination of upward regulating reserves. The 3 standard deviations were set to include most of the variability caused by DGPV, grid-scale PV, grid-scale wind, and load and exclude the most extreme outliers that could drive excessively high regulating reserve requirements. Regulating reserves are required for the grid scale resources, DGPV, and load to account for the variability in each of those categories. In the example provided in subpart c., it appears regulating reserves are only being considered for grid scale resources.

[38] *Id*. at 11-12.

As the Companies work towards the next Review Point filing which will include the grid service definitions, it will continue to work with TAP and Ulupono to address any concerns.

14. Item Ulupono-14

> **Hourly shapes for loads and renewable resources.** When running RESOLVE, it is important that the sample days reflect the range of weather conditions that the power system may experience, including both difficult days and typical days, with appropriate probability weights. The hourly wind, solar and load profiles should also correctly reflect the weather-driven correlation or anticorrelation between these elements. The most common and straightforward way to do this is to select a collection of historical dates that reflect the range of conditions that have been seen in the past. Then each future sample day is defined in terms of one of these historical dates, and wind, solar and load profiles for the future day are calculated based on weather and loads on the corresponding historical date.
>
> Hawaiian Electric has briefly discussed the selection of sample days for RESOLVE, but it is not clear what method they used to select sample days, or whether those days include the correct distribution or correlation for wind and solar power (only loads were shown). It is also unclear whether the loads used in RESOLVE will be driven by the specific weather on these sample dates (e.g., rescaled versions of historical loads) or generated more abstractly, e.g., based on average weather. It would be helpful for Hawaiian Electric to clarify these issues before proceeding with the modeling.[39] (footnotes omitted)

Hawaiian Electric Response:

Distributions for wind and PV can be provided, similar to the data shown for load that are outputs of the RESOLVE day sampling tool. The day weighting considers several years of historical hourly data in its selection. Additionally, the TAP previously reviewed this recommendation in their June 1, 2021, Grid Services and Planning Criteria Feedback at page 10, stating:

> Ulupono states "Including the worst-weather day in the RESOLVE optimization will ensure that the system has a least-cost design that provides enough power at all times. Consequently, it is not appropriate to apply an ERM as an additional, arbitrary mechanism to achieve generation adequacy". The TAP does not agree with this statement. While selection of a broad range of daily operations and best estimates of reserves might provide a closer estimate for capacity growth, final determination of the

[39] *Id*. at 13.

cost-effective, reliable path forward requires use of all the tools identified as was discussed in detail in Section 3.

15. Item Ulupono-15

Distributed Energy Resource (DER) Adoption. Hawaiian Electric's "base" DER adoption forecast is nearly identical to the "low" forecast, which assumes customers can only generate power for their own consumption. The "base" forecast includes an incentive for export, which results in a negligible amount of export. Even the "high" forecast only considers night-time export. These forecasts may leave as much as 75 percent of potential roof area untapped (available rooftop potential is around 4,000 MW according to Google Project Sunroof) . We recommend that Hawaiian Electric adopt a framework that encourages customers to export power for use by other customers at avoided cost, e.g., via a feed-in tariff that locks in long-term payments that are competitive with PPAs for grid-scale solar. This would enable DER to serve as a backstop resource if Hawaiian Electric cannot develop sufficient grid-scale solar power. We also recommend that the RESOLVE modeling include the option of large-scale DER export, using the ATB costs for DER. This is not likely to be an important factor in the results if the model has access to enough grid-scale solar resources to meet each island's needs. However, it will be very important if some islands are modeled as being short of grid-scale solar, e.g., in scenarios with more restrictions on land use. In those cases, if DER export is not included, RESOLVE will incorrectly select higher-cost biofuels or offshore wind instead of tapping into the full DER potential.[40] (footnotes omitted)

Hawaiian Electric Response:

The primary goal of the Grid Needs Assessment is to identify the amount and timing of grid needs over the planning horizon. The sales forecasts already consider various amounts of DER adoption through the base, low and high bookend cases that will be analyzed. A DER aggregator will also be available in the models as a resource option that can provide grid services, above the forecasted amount of DER in the sales forecast.

The value of DER to the system can be more specifically assessed in the DER freeze cases as part of the program design phase of the IGP process. This value will be defined by the replacement resources that are selected by the models, in the absence of a forecasted uptake of DER. Further, as part of the solution sourcing phase, current DER programs may be updated or

[40] *Id*. at 13-14.

created similar to the work that was recently completed in the DER program track in Docket No. 2019-0323.

C. Response to Joint Parties' Comments

1. Item JP-1

> Although Hawaiian Electric has made some recent progress in incorporating stakeholder feedback, the IGP process continues to pose challenges and frustrations. The Joint Parties have proposed numerous sensitivities and analyses that Hawaiian Electric has ultimately rejected. Hawaiian Electric has also made last-minute changes to the sensitivities under consideration without adequate vetting and over the stakeholders' objections.[41]

Hawaiian Electric Response:

As discussed herein and in the August Update, the Companies have made significant modifications to the inputs and assumptions based on direct stakeholder feedback, including that of the Joint Parties. The Joint Parties reference rejected sensitivities from their Comments on the HECO Companies' First Review Point, filed on February 25, 2021, at 11-12. On pages 11-12, the lone sensitivity on that list includes a no biomass/biofuel scenario. The Companies confirm that this sensitivity has been included as part of the Land Constrained Scenario, where biomass is removed as a resource option.

The Company has incorporated stakeholder proposed sensitivities that would be instructive in testing certain assumptions of other scenarios that could occur. For example, based on stakeholder feedback, the Companies added an EV and EE freeze sensitivity. Also, in light of differing stakeholder views regarding solar development potential, the Companies modified its Land Constrained scenario. In addition, see the Companies' response to Item CA-2, above, regarding the objective of sensitivities and the TAP's recommendation. Several of the sensitivities previously proposed by the Joint Parties were either already captured by the

[41] Joint Parties' Comments at 1.

bookends or more appropriate to be considered in other dockets, *e.g.*, DER freeze modeling in the DER docket to inform scheduled dispatch program design. The Joint Parties feedback was incorporated in the assumptions used to define DER and EV layers for the bookend cases.

2. Item JP-2

> Further, no amount of stakeholder meetings can change the fact that, under the current IGP process, Hawaiian Electric has sole access to much of the underlying data and formulas for the inputs and assumptions (such as the DER adoption rate and sales forecasts), which inform the IGP process. This limits stakeholders' ability to meaningfully opine on the reasonableness of the proposed inputs and assumptions except at a high level or where Hawaiian Electric adopts public inputs.[42]

Hawaiian Electric Response:

As explained in the August Update at 6, the Companies have stood up a specific working group, the FAWG, to evaluate the Company's forecast methodologies and resulting underlying forecasts. The FAWG engaged 18 different organizations and 26 different individuals and various docket intervenors during the stakeholder engagement process. The FAWG met with stakeholders eight times (including a two-day meeting in May 2019) before finalizing the forecast. A 36-page Appendix C, attached to the August Update explains, in great detail, including formulas and data, the methodologies used to develop the underlying forecasts. Additionally, a vast quantity of data is provided on the Company's FAWG webpage: https://www.hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning/stakeholder-engagement/working-groups/forecast-assumptions-documents

Moreover, in the January 19, 2021 Review Point Exhibit A.3 at 3, one of the TAP's Key Conclusions stated, "TAP members generally agreed that there is a good link between the econometric models and forecasting load growth, but also noted that recent trends may have changed the relationship between economic growth and load growth. While the larger datasets

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[42] *Id.* at 1-2.

are preferred, econometric modeling should ensure that recent year data do not show a significantly different economic relationship to load growth."

In conclusion, the Joint Parties appear alone in this view. Other Parties and stakeholders have not raised the issue of data and access to data. In fact, other Parties and stakeholders such as Ulupono, and the TAP, have used the information and data provided to make suggestions to improve the IGP process. To the extent that certain information may not have been provided, the Companies note certain issues have been placed into the parking lot to be resolved in future planning cycles because that information may not currently exist and would require further evaluation, for which the Joint Parties did not raise issues regarding the "parking lot".

3. Item JP-3

> While the broad bookends proposed by Hawaiian Electric will likely provide useful information, a key for the future success of the IGP docket will be how this information is used and, if necessary, how the inputs and assumptions will be updated. If the intent is simply to tweak the existing base case, then this exercise will be futile. Instead, the bookends and future sensitivities should inform a series of preferred options that accelerate progress towards Hawai'i's clean energy mandate.
>
> For example, the Brattle Electrification study for Pepco's climate plan estimates significant load growth as a result of rising levels of electrification. Nonetheless, Pepco anticipates energy efficiency and load flexibility (including residential behind the meter storage) will reduce peak demand growth by 40% between now and 2050 (*see* **Fig. 1**). Pepco also states it believes it can manage this peak demand growth at the distribution system level. It is hoped that Hawaiian Electric is viewing the current bookends with the intent to examine the feasibility and likelihood of a similar result and accelerated RPS coming out of the IGP process.[43] (actual figure and footnotes omitted)

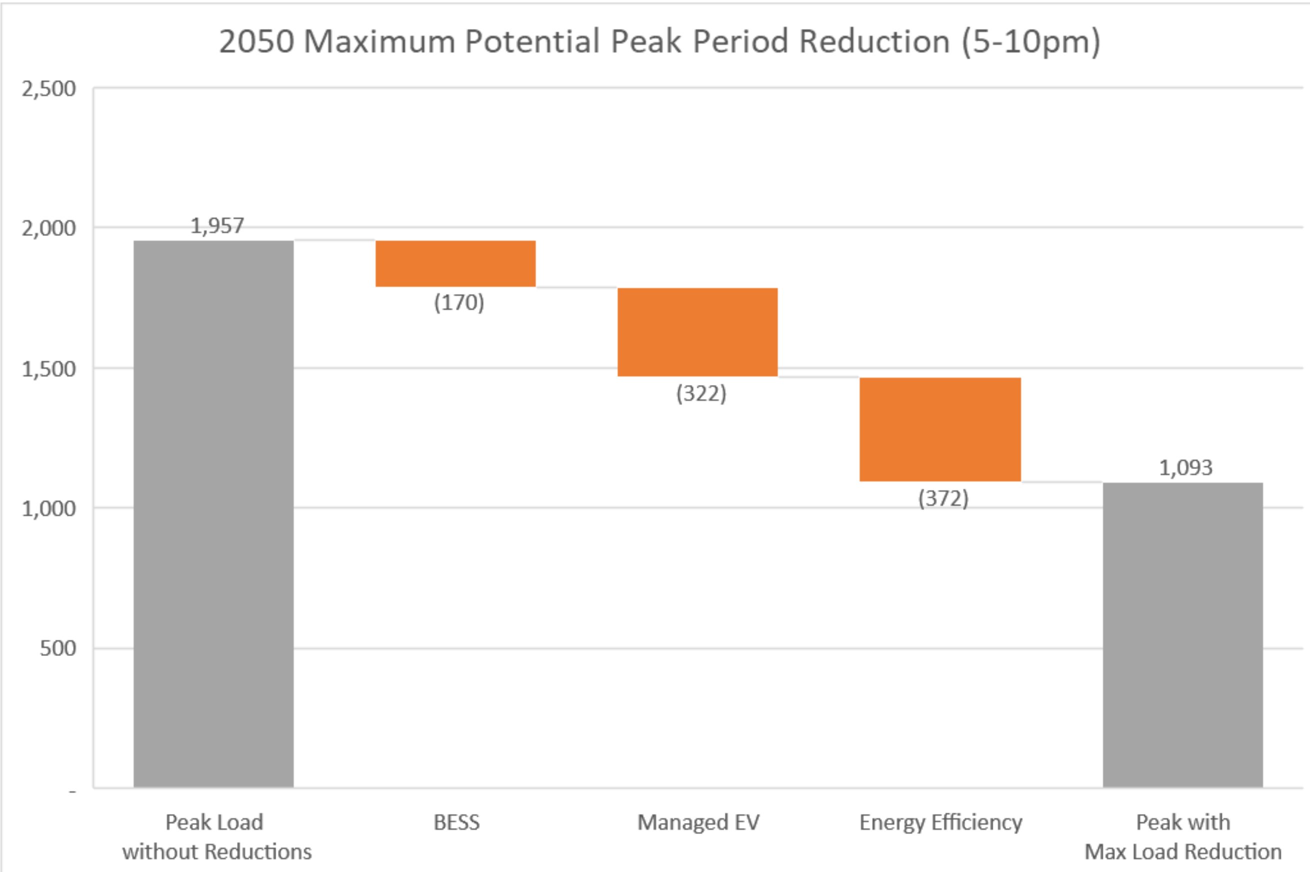
Hawaiian Electric Response:

The base case is intended to represent what is most likely to occur based on econometric models, market factors, and current and projected policies. The Companies, upon the recommendation of the TAP, developed high and low bookend scenarios. As stated by the TAP,

[43] Joint Parties' Comments at 2.

"The objective of the bookend would be to determine the lowest and highest possible demand. Does it change the resource mix dramatically? If the same types of resources are selected, then perhaps we shouldn't focus so much time on one bookend, e.g., increased EV uptake, etc." The Companies agree with the Joint Parties that the bookend scenario may be useful in informing grid needs and solution sourcing of programs, pricing, and procurements.

Further, the forecast assumptions include load reduction and flexibility. Similar to the Pepco climate plan, as the Joint Parties note, load reduction and flexibility can significantly reduce peak demand growth by 2050. The following figure demonstrates the significant potential load reduction during the peak period of 5-10pm on O‘ahu that can be achieved through future energy efficiency measures, managed EV charging and behind-the-meter batteries based on the Companies' base case forecasts. This figure illustrates the maximum potential of each layer, where the impacts are not necessarily coincident (*i.e.*, the maximum potential of each layer in 2050 may not occur at the same time and date).



4. Item JP-4

> Finally, the Joint Parties encourage continued access and availability to Hawaiian Electric's grid planning such as requiring updates and continued access to Hawaiian Electric's RESOLVE model. The Joint Parties reiterate that to enhance transparency, flexibility, quality, and overall confidence in the utility planning process, the Commission should require all utilities to open up the modeling process, as California has already done.[44] (footnotes omitted)

Hawaiian Electric Response:

The Companies note that it has transparently provided workbooks, available at https://www.hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning/stakeholder-engagement/key-stakeholder-documents, that contain the inputs and assumptions that the Company itself uses in its modeling tools. Additionally, many of the Joint Parties and their

[44] Joint Parties' Comments at 3-4.

consultants have access to the RESOLVE model as provided through the DER Docket. Moreover, as the Joint Parties note, other Parties such as Ulupono Initiative have successfully been able to conduct their own modeling and analysis using the inputs and assumptions that have been provided by the Companies. As a case in point, Ulupono, through its consultant, has access to a resource planning modeling tool that has allowed the organization to advocate for removing land constraints on grid-scale PV. *See* Ulupono Presentation to the IGP Stakeholder Council on June 18, 2021, *available at* https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/igp_meetings/20210618_igp_stakeholder_council_switch_analysis_slides.pdf (last visited Sept. 8, 2021).

The Joint Parties have sufficient access to information to be able to populate software models and conduct their own analysis for discussion within the docket proceeding.[45] Additionally, the Companies are working with the TAP to independently review the Companies' modeling methods and tools. This includes an in-depth independent evaluation on the Companies' reliability guidelines where the TAP will use their own modeling methods and tools to conduct an assessment of the energy reserve margin.

5. Item JP-5

The Joint Parties responded to PUC QUESTION 1 (*Does the August IGP Update thoroughly address every Commission concern articulated in Order No. 37730? If not, please explain what concerns remain.*) as follows:

> No. For example, the August IGP Update does not adequately address the Commission's concerns stated in Order No. 37730 regarding Hawaiian Electric's thermal generating unit retirement plans. Although Hawaiian Electric has included a retirement plan in its August IGP Update, this one-page plan lacks any rationale for the timing of and units

[45] *See, e.g.*, the Companies' July 2, 2020 letter to the Commission in Docket No. 2019-0323 addressing the RESOLVE modeling tool.

selected for retirement. By comparison, Hawaiian Electric's retirement plan in its December 23, 2016 Power Supply Improvement Plan Update Report included more than one dozen pages of explanation. In its Inputs and Assumptions—or at the very least in its forthcoming Grid Needs Assessment—Hawaiian Electric should thoroughly explain its rationale for the proposed retirement plan and must also comply with the Commission's directives to:

(1) "analyze how using a retirement plan in the base case changes the optimization of new renewable and storage resources outside of incremental compliance needs for O'ahu"; and

(2) "thoroughly analyze and clearly explain why the model selects such large amounts of biomass and biofuel resources, including what cost assumptions (e.g., fuel prices) in the modeling contribute to this selection."

Without this information or analyses, the Commission lacks any basis for approving Hawaiian Electric's proposed retirement plan.[46]

Hawaiian Electric Response:

Please also reference the Companies' response to Ulupono-9 above. The retirement plans in the August Update are starting assumptions that will be further analyzed during the upcoming Grid Needs Assessment phase; and may be iterated on, as needed, consistent with the modeling framework.

Ulupono's independent analysis using the same O'ahu retirement assumptions set forth in the August Update, demonstrates that between 151 MW and 301 MW of new thermal generation is added to the system, and when combined with remaining thermal units, range between 973MW and 1,124 MW of thermal generation. (https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/igp_meetings/20210618_igp_stakeholder_council_switch_analysis_slides.pdf at 25-26).

The Company's own analysis is directionally consistent with Ulupono's analysis. When using the August Update retirement assumptions that retire AES (180MW), Waiau 3 and 4 (94

[46] Joint Parties' Comments at 4-5.

MW), Waiau 5 and 6 (108 MW) , Kahe 1&2 (165 MW), for a total of 547 MW, the RESOLVE model chose to build more grid-scale PV and a 165 MW biomass unit prior to 2030. (See https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/stakeholder_council/20210618_sc_meeting_presentation_materials.pdf at 35.) In other words, using planning assumptions to remove 547 MW of fossil fuel powered units over the next decade, the RESOLVE model replaces only a fraction of firm generation with new firm generation. The 160 MW new firm (biomass) generation is within the same range as Ulupono's independent analysis. The Company believes the planning retirement assumptions included in the August Update represent a reasonable starting point and is consistent with the Commission's directives as validated through Ulupono's independent analysis.

6. Item JP-6

The Joint Parties responded to PUC QUESTION 3 (*Is Hawaiian Electric's proposed high electric vehicle forecast sensitivity reasonable, including the underlying assumptions? If not, please explain why not, and what modifications are necessary.*) as follows:

> No. As stated in Blue Planet Foundation's letter filed on August 18, 2021, Hawaiian Electric's approach of modeling high EV adoption *without* managed charging is unreasonable. At the June 17, 2021, Stakeholder Technical Working Group, Hawaiian Electric proposed including a sensitivity titled "Faster Customer Technology Adoption," which assumed high uptake of rooftop solar, EVs, and energy efficiency measures, along with managed EV charging (*see* **Fig. 2**).
>
> Based on the understanding that Hawaiian Electric would consider high EV uptake both with and without managed charging, Blue Planet Foundation supported including a high EV forecast of 100% ZEV by 2045. Hawaiian Electric's August IGP Update, however, omits the "Faster Customer Technology Adoption" sensitivity or any scenario or sensitivity that pairs high EV uptake with managed charging. This omission prevents any valuation or comparison of managed versus unmanaged charging in a high-EV environment. Without this analysis, the Commission, Hawaiian Electric, and stakeholders lack critical information to inform near-term planning and managed charging policies as

> Hawai‘i pursues its goals to electrify transportation.[47] (actual figures and footnotes omitted)

Hawaiian Electric Response:

Please see the Companies' reply to Item CA-2 above. Further, as part of the grid needs assessment, LoadSEER will be used to determine distribution system load driven grid needs in the base, low, and high electrification cases.

7. Item JP-7

> Although evaluating high EV adoption alongside unmanaged charging may be appropriate for a high bookend scenario, there is no valid reason for refusing to assess "Faster Customer Technology Adoption" as a standalone sensitivity, along with the several other standalone sensitivities proposed. Hawaiian Electric has already layered the underlying data for this sensitivity and presented this analysis at the September 7, 2021 Stakeholder Technical Working Group meeting. These layers show that high EV uptake along with managed charging, high rooftop solar uptake, and high energy efficiency (*see* "High Adoption" (teal line) in **Figs. 3 & 4**) significantly reduces O‘ahu's near-term GWh sales and near-term MW peak below the "High Load" (dark orange line) scenario, in which high EV uptake along with unmanaged charging, low rooftop solar uptake, and low energy efficiency is assumed. This information should be incorporated and modeled as a standalone sensitivity in the IGP process to inform planning, procurements, programs, and pricing going forward.[48] (actual figures and footnotes omitted)

Hawaiian Electric Response:

Although the high technology adoption scenario was originally proposed to include managed EV charging, the "Peak Forecast – High Adoption" teal lines on the peak comparison charts included in the September 7, 2021 Stakeholder Technical Working Group meeting (slides 17, 19, 21, 23 and 25) represent high EV uptake with unmanaged charging, high rooftop solar uptake and high energy efficiency.

The high adoption (teal line) scenario can inform programs and pricing; however, it is not instructive to assessing the total system grid needs, as recommended by the TAP. If the Joint

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[47] Joint Parties' Comments at 5-7.
[48] Id. at 7.

Parties' intent is to inform new programs and pricing structures, those are best accomplished using the various DER "Freeze" sensitivities that were added. Sensitivities #4-6 at p. 111-112 of the August Update explain the purpose of DER, EE, and EV freeze cases, "to determine the appropriate mechanism for solution sourcing and program design". The intent of the "freeze" cases are to take the base forecasts, as those are what the Companies reasonably expect the market to bear, and design programs based on the "value" of that freeze case. Because the forecast layers are embedded in the forecast, the net load and resulting grid needs are what is needed to be served by grid-scale resources. The EV freeze scenario would cover the Joint Parties intent to inform programs; however, if an EV freeze case that compares high managed charging versus high unmanaged charging is desired by the Commission, the Company suggests that this type of analysis can be completed to inform solution sourcing but may require additional time to complete than the currently scheduled 6-month duration of the grid needs assessment phase.

Finally, as noted in the response to Item CA-2, the modeling framework discussed at the June 4 Technical Conference, allows flexibility in the process to iterate modeling on an as needed basis. The Companies believe that if there are significant differences between the base and high load bookend, that a discussion with stakeholders can determine whether an iteration such as one that the Joint Parties suggest is appropriate or necessary.

8. Item JP-8

The Joint Parties responded to PUC QUESTION 7 (*Do the assumptions regarding future DER programs represent a reasonable best estimate for this round of IGP? If not, please suggest alternative assumptions.*) as follows:

> While there have been significant improvements to the DER forecast assumptions, several baseline assumptions regarding current and potential incentive programs may inappropriately impact the bookend cases.
>
> First, it is unclear whether Hawaiian Electric is appropriately accounting for federal and state tax incentives. Hawaiian Electric indicated it would apply a $5,000 cap on residential PV only systems for "Federal and State investment tax credits" and a cap on residential PV+storage systems of $10,000 beginning in 2022.17 However, no such "cap" for the federal investment tax credit ("ITC"), and applying this cap would significantly reduce the incentive amount available to most clean energy projects.[49] (footnote omitted)

Hawaiian Electric Response:

The Companies inadvertently stated in error that federal investment tax credits were capped in the DER uptake modeling. The bullet points stating the assumed caps were intended to apply only to the description of the Hawai'i state renewable energy income tax credits. Federal investment tax credits were not capped in the DER uptake modeling. The Company apologizes for any confusion this may have caused.

9. Item JP-9

> It is further unclear whether Hawaiian Electric is correctly applying the cap applicable to Hawai'i's renewable energy income tax credit, as it applies to each "5kW system" installed. As an example, a 20 kW system could be eligible for $20,000 in state tax credits.[50]

Hawaiian Electric Response:

The cap on Hawai'i's renewable energy income tax credit was applied to each "system" as defined in Hawai'i Administrative Rules, Title 18, Department of Taxation, Chapter 235 Section 12.5. As the Joint Parties correctly point out, it is possible for the resulting Hawai'i renewable energy income tax credit to amount to more than $5,000 if a customer installs more than 5kW PV.

10. Item JP-10

[49] *Id.* at 9.
[50] *Id.*

Similarly, it is uncertain what federal ITC assumptions are being utilized in Hawaiian Electric's high-end DER bookend. The August IGP Update indicates an extension of ten years but does not clarify at what percentage the ITC is maintained. Congress's and the Biden Administration's infrastructure and budget reconciliation packages, *i.e.*, the "Build Back Better" plan, potentially increases the ITC back to 30% and keeps it at that higher level for ten years. Yes, the August IGP Update shows the federal ITC stepping down and being reduced to zero beginning in 2024.[51] (footnote omitted)

Hawaiian Electric Response:

The federal ITC for the high DER scenario was assumed to remain at 26% until the end of 2032.

11. Item JP-11

Second, the lower bookend case should realistically take into account the impact of Hawaiian Electric's rate design proposals. Hawaiian Electric assumes a 3.336 kW "peak" for an average residential customer. This seems unlikely. A typical, modern electric clothing dryer can consume 4-5 kW. In conjunction with any other electricity usage typically found at a home, such as a refrigerator, lights, rice cooker, etc., the average residential customer would likely see a higher peak demand charge (over a 15 minute period) than what Hawaiian Electric proposes.

Further, demand charges would greatly impact current and future electrification efforts. The new electric Ford F-150—a vehicle that currently represents 1 in 16 cars driven in the United States today—will charge at a peak rate of 18 kW. With a $3 a kW proposed demand charge, a new Ford F-150 owner could anticipate at least a $54 a month new "charge" as a condition of electrification. Hawaiian Electric's rate design proposals, based on a 15 minute interval "peak," would likely result in significantly increased residential charges on customers seeking to modernize and electrify their homes. While DERs could help defer the impact of some of these demand charges—and keep load off the grid—the lack of visibility or transparency surrounding a demand charge would likely depress overall market adoption.[52] (footnote omitted)

Hawaiian Electric Response:

In the August Update, at 50-51, the Company stated: "One of the key components of the Advanced Rate Design ('ARD') discussed in the DER docket includes the implementation of

[51] *Id*. at 9-10.
[52] *Id*. at 10.

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 discharge the system in the evening, and in managed charging cases, customers charge electric vehicles during the day. 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 Proposal40, 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 Company is further evaluating TOU for non-DER and non-EV customers. …. However, the Company believes that the high and low bookend scenarios already provide significant load shaping; for example, see Figure 4-5. Any impacts of increased demand charges 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." The Companies provided support for residential customer average peak demand of 3.336 kW in the response to PUC-IR-137 in Docket No. 2019-0323.

With regard to the Joint Parties' assertion that customers will have a "lack of visibility or transparency surrounding a demand charge," with implementation of Advanced Metering Infrastructure (AMI), customers will have detailed information on their consumption that will provide them with the ability to make informed decisions regarding their consumption and the potential impact to their bill. AMI customers will have access to 15-minute interval data through an online Energy Portal, be able to sign-up for and set energy alerts, and utilize rate comparison tools to ensure they are on the best rate plan given their energy consumption patterns. In addition, AMI customers who are placed on approved TOU rates will receive information materials on the TOU rate elements and will have the opportunity to assess how their energy usage (as indicated by Energy Portal data) aligns with TOU rate charges.

12. Item JP-12

The Joint Parties responded to PUC QUESTION 8 (*In the August IGP Update, Hawaiian Electric proposed a modification to the bookend scenarios, replacing the higher and lower*

customer technology adoption bookends with high and low load bookends. Do these high and low load bookend scenarios provide a reasonable and valuable structure for assessing future grid needs and solutions?) as follows:

> While this may be a matter of semantics, there are differences between conducting a high and low load analysis versus understanding the ability of technologies to support the grid and reduce overall system peaks. For example, a high DER adoption rate may mask future load growth from overall electrification (for example, a high DER and high EV adoption scenario). Much of the time, increased EV load growth may be served from behind the meter solar and storage. As such, Hawaiian Electric would likely treat this scenario as a "low load" scenario. Nonetheless, such a scenario could also show occasional large system peaks, that is, large amounts of load suddenly appearing a small number of times over the year when DERs do not serve demand. This could trigger the need for substantial utility investment to meet the few times a year where DERs are not otherwise addressing the increased load. Nonetheless, understanding the impacts of high technology adoption—and the ability to create flexible loads—should help a reasonable utility system planner to design an appropriate program, procurement, or pricing option that could adequately address these outlier circumstances.[53]

Hawaiian Electric Response:

Please see the Companies' response to Item JP-3, including the figure that shows the significant load flexibility and demand reduction provided by the various forecast layers. As the Joint Parties note in their response, high DER may mask future load growth from electrification in a high EV adoption scenario. For this reason, the high and low customer technology adoption bookends were replaced with high and low load bookends.

D. Response to PHOW Comments

1. Item PHOW-1

> **COMMENTS ON ITEM NO. 4: GRID SCALE PV AND WIND ASSUMPTIONS**
>
> **A. The 30% Slope Assumption Is Not Feasible.**
>
> PHOW notes with some concern that the August IGP Update reflects a conclusion by the Company that slopes up to 30% could be developed, with some additional cost adder, and this 30% slope assumption should be used as a base case assumption in the grid modeling.
>
> …

[53] Joint Parties' Comments at 11.

PHOW does not agree with the conclusion that slopes up to 30% "could be developed" with "some additional cost adder" for the following reasons.

First, this conclusion is contrary to and not supported by practical, real-world experience of developers of most utility scale solar energy projects. Specifically, the PHOW development team includes developers of solar energy projects with substantial experience in Hawaii and other jurisdictions. Although construction on steeper slopes is technically possible and may be pursued in some cases, it is rarely attempted by large, commercial-scale projects because of the complexity, expense and safety concerns of working on steep surfaces. Based on that experience, it is respectfully submitted that the conclusion that slopes up to 30% high can feasibly be developed with an additional cost adder is not realistic or tenable.

….

Specifically, the Alt-1 scenario referenced in the August IGP Updateassumes construction on slopes up to 30%, and based on that assumption estimates that more than 3,800 MW of solar PV could be developed on Oahu. The estimate of developing more than 3,800 MW of solar PV on Oahu, founded on the 30% slope assumption, is not realistic or feasible.

While the grid modeling does not dictate which types of projects may be proposed or selected in future procurements, such an overestimate of solar potential will create unrealistic expectations of the solar industry. If the 30% slope assumption remains the base case scenario, then the energy resource planning and modeling process is likely to conclude – inaccurately – that Oahu can develop much more utility scale solar energy than is realistically possible, thereby creating an appreciable risk that the Company and its customers will be disappointed by the low number or high cost of future solar PV projects.

Third, the Company has agreed to show a sensitivity illustrating a "Land Constrained" scenario of approximately 270 acres on Oahu, which PHOW recommended and supports as a more realistic estimate of developable land available for solar PV projects. This Land Constrained scenario is difficult to reconcile with the 30% slope assumption, and should be preferred and utilized as an assumption over the latter. More specifically, it should be used as a base case assumption rather than as a bookend assumption.

Finally, if the Company insists on using the 30% slope assumption, then those solar projects will be significantly more expensive, and that increased cost should be reflected in the resource cost assumptions. The complexity and civil grading work that would be required could potentially increase the cost of large commercial solar PV projects by 10% to 20%, or more. This additional cost should also be reflected in the resource price modeling of solar resource, along with the 30% slope assumption (if used).[54] (footnotes omitted)

Hawaiian Electric Response:

[54] PHOW Comments at 2-4.

The Company's experience in recent procurements on O'ahu comports with PHOW assertions on land availability to develop solar, particularly on high slopes. The Company also believes, consistent with HRS §269-145.5, that a diverse portfolio of resources will be needed to achieve its clean energy mandates while maintaining reliability and resilience of the grid. The Company notes that there are two ways the August Update have proposed to partially reflect these realities. The first is through the Land Constrained scenario, where a lessor amount of grid-scale PV is made available to the model. The second, is the additional on-going Renewable Energy Zone ("REZ") analysis, through which the Company will be providing costs for transmission upgrades required to connect various zones on Oahu, Maui, and Hawaii Island. The REZ analysis will provide incremental interconnection costs to provide transmission interconnection points to these zones, which would have the effect of increased cost for a particular area sited predominantly for solar. The Company does not object if the Commission believes that a lower solar potential should be used as the base assumption. For example, one of the other solar potential scenarios from the NREL potential study (see https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/stakeholder_council/20210730_sc_heco_tech_potential_final_report.pdf) could be used as the base assumption, such as the Oahu PV-1-3 scenario with a potential of 907 MW. Additionally, representatives from Ulupono stated at the September 7, 2021 STWG meeting that in conducting additional research, developing solar on slopes up to 20% instead of 30% as assumed in the Alt-1 scenario, seems to be more feasible.

2. Item PHOW-2

B. The August IGP Update Should Reflect the HNEI Report Analysis.

In addition and related to its concerns over the 30% slope assumption, PHOW notes with concern that the August IGP Update fails to properly take into account a key analysis by the Hawaii Natural Energy Resource Institute ("HNEI"). Specifically, HNEI previously reported that Oahu could reach a maximum of approximately 70% renewable electricity on solar and batteries. Beyond that, types of resources other than solar plus storage projects would be necessary. The August IGP Update does not appear to reflect this important input from HNEI. To the contrary, it appears to suggest that all of Oahu's generation could potentially be met with solar and battery storage, and thus other technologies or resources may not be necessary – an assumption that is not well supported.[55] (footnote omitted)

Hawaiian Electric Response:

Hawaiian Electric does not disagree with HNEI's analysis. The Company does plan, through the Grid Needs Assessment phase of the IGP process, to validate or refute the HNEI's analysis.

3. Item PHOW-3

C. Modeling Should Properly Account for Tax Credits.

A further comment relates to the Company's modeling of the available tax credits for solar, onshore wind and offshore wind projects. The relevant date for claiming tax credits is Commercial Operations Date ("COD"). Yet in its grid modeling assumptions, the schedule of federal tax credits lists the latest year that projects may begin or commence construction to qualify for the tax credit, rather than listing the latest year when project may reach its COD. The latter date is a more relevant because it indicates the latest date by which projects may be completed to qualify for the available tax credit. Offshore wind projects, for example, that begin construction or purchase "safe harbor" equipment by 2025 would thereby qualify for the 30% federal tax credit through 2035. The August IGP Update should be clarified and corrected consistent with the foregoing to ensure the benefits of federal tax credits are secured.[56]

Hawaiian Electric Response:

Please see Response to Ulupono-1. Updates will be made to include the safe harbor provision for offshore wind through 2035.

4. Item PHOW-4

[55] *Id*. at 4.

[56] *Id*. at 4-5.

D. Modelling Should Also Consider Long-Term Procurement.

In the recent IGP Stakeholder Conference, the Company indicated that the grid modeling would consider offshore wind as an available resource in all modelling scenarios beginning in the year 2030. PHOW supports this assumption insofar as 2030 is the earliest reasonable date by which offshore wind could be available as a resource. If the grid assessment will allow the model to select long term resource technologies such as hydroelectric, pumped storage, flow batteries, geothermal and offshore wind for COD as early as 2030, then the results of the assessment should also address steps to facilitate the procurement of such long term projects by 2030. Accordingly, PHOW would recommend that the Company extend the COD time frame in its next solicitation to allow CODs out to 2035, as doing so would allow a variety of long term technologies to propose projects that may meet the grid needs identified by the assessment.[57]

Hawaiian Electric Response:

The Companies confirm that offshore wind will be an available resource starting in 2030 in all scenarios. It is the intention for the next competitive procurement during the solution sourcing phase of the IGP process to allow projects with longer development times to compete. Given this feedback, the Company will consider a 2035 COD as it starts to put together a proposed framework for the solution sourcing phase.

5. Item PHOW-5

E. Renewable Energy Zones Should Not Delay Future Procurements and Projects.

As an additional comment, the Company's proposal to develop Renewable Energy Zones ("REZs") and expand the Oahu transmission system to accommodate more renewables is an ambitious process, but this process should not preclude the continued procurement a future energy projects. The REZ proposal would be for a new process that is still under development and has not received Commission approval, and the timing of developing and implementing this process therefore should not precede or in any way serve to delay future projects.[58]

Hawaiian Electric Response:

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[57] *Id.* at 5.

[58] *Id.*

Maximizing the use of existing transmission and distribution infrastructure to accommodate increasing levels of renewable energy is essential to managing overall impacts to customers and the community. However, there are technical limitations on the existing system to reaching future renewable goals, requiring proactive assessments of infrastructure required to attain these goals. The intent of the REZ analysis is to reflect the technical realities of interconnecting high amounts of renewable resources in certain parts of each island. The Company is also interested in evaluating whether the Grid Needs Assessment (through its scenarios and sensitivities) requires REZ to be developed in order to reach 100% renewable energy. The Company recognizes the importance of community engagement in developing the REZ and will continue those efforts in parallel.

6. Item PHOW-6

F. Future Procurements Should Include Longer-Term Projects.

The Company did not address the timing of future procurements in the August IGP Update. The Company's plan is to complete the Oahu grid study to inform the next Request for Proposals solicitation ("RFP"). The grid modeling results may select long-term projects such as offshore wind, hydroelectric or solar projects that require transmission upgrades. In prior IGP working group meetings, Company representatives stated that while long term projects are important and necessary, developing a long term RFP would be necessary and complicated.

PHOW suggests that developing a separate format for a long term RFP may not be necessary. Instead, if the Company extends the COD time frame in its next solicitation to allow CODs out to 2035, then it is not necessary to develop a separate "Long-Term RFP." All projects of varying technologies could then compete in the same solicitation and be evaluated based on their proposed completion dates. The Company could select a combination of nearer term and longer-term projects that best addresses generation and grid needs, based on the results of the upcoming grid assessment.[59]

Hawaiian Electric Response:

[59] *Id*. at 6.

The Company confirms its current thinking on the next round of competitive procurements that are expected to follow the Grid Needs Assessment phase, contemplates a single procurement with a longer COD date (*i.e.*, 2035) allowing near- and long-term projects to compete. The resulting portfolio of solutions could be a mix of CODs. However, the Company does expect that longer term projects may not be able to meet the same requirements as short-term projects such as site control. The Company expects to discuss these matters with stakeholders in the future.

E. Response to County of Hawaii Comments

In response to Order No. 37927 Public Utilities Commission's question 11, COH provides the following questions that they request be answered in advance of the October 1st Input and Assumptions filing.[60] The Companies include their responses where applicable below:

> 1) The draft *Grid Needs Assessment and Solutions and Solution Evaluation Methodology* mentions the use of curtailed power for virtual inertia in the system, but does not go into much greater detail about this curtailment assumption in the modelling work that the Companies are doing to support this report. Where do forecasts for curtailed power fit into the Companies' current input and assumptions for the IGP?
>
> 2) Has HECO considered implementing any technologies to use or store curtailed renewable electricity (from existing or planned new generation) so it is not wasted? If so, what input and assumptions have been made about the types of technologies which could be employed to use curtailed renewable electricity?
>
> 3) For the Phase 1 and 2 PV+BESS solar farms, what is the projected wasted PV electricity production once the battery has been fully charged daily/monthly annually?

Hawaiian Electric Response:

The Company is assuming the use of RDG and firm PPAs in its modeling, whereby an annual lump sum is paid for availability of the facility. This allows the facility to be used for a

[60] COH Comments at 3.

multitude of services such as regulating reserve and capacity. These services are provided even when we are not taking energy and if the energy were provided to another party, these services may potentially not be available to us. In this case, the Company would be paying for services that cannot be utilized.

III. HAWAIIAN ELECTRIC RESPONSES TO COMMISSION QUESTIONS

In addition to the Companies' reply to the Parties' comments set forth above, and the Companies' responses to the Commission's questions as a part of those reply comments, the Companies also provide these additional responses to the questions for the Commission's consideration.

(1) Does the August IGP Update thoroughly address every Commission concern articulated in Order No. 37730? If not, please explain what concerns remain.

Yes. In addition to the June 4 Technical Conference, the Companies have held numerous virtual meetings with stakeholders through the STWG, smaller group meetings, email exchanges[61] to incorporate stakeholder feedback addressing each of the ten areas in the Review Point Guidance at pages 51-52. Certain of the ten items will be addressed in the next Review Point filing scheduled for early November.

(2) Do Hawaiian Electric's fuel forecast sensitivities adequately capture the risks of importing fuel?

Yes. As discussed in the August Update at pages 21-23, any cost adders (*i.e.*, \$4-\$6 per barrel) would be covered by the high fuel forecast now adopted by the Companies. Further, no stakeholders commented on this specific issue and Ulupono has now expressed their support for the fuel price forecasting method at page 3 of their comments.

[61] Ulupono Comments at 3.

(3) Is Hawaiian Electric's proposed high electric vehicle forecast sensitivity reasonable, including the underlying assumptions? If not, please explain why not, and what modifications are necessary.

While the CA expressed concerns whether the high forecast is reasonable, the Companies adopted a high forecast recommended by Blue Planet Foundation to model 100% ZEV by 2045. The Company notes that while Blue Planet has concerns about a high EV sensitivity, it has not refuted the use of the high EV forecast.

As the TAP noted, and provided in response to CA-2, EV adoption is highly uncertain at this time, which warrants testing resource plans against a wide band of potential EV adoption, which the Company has done. Though the CA is concerned whether the high EV forecast is within the realm of possibility, at the root of their concern is additional infrastructure investments because of the high forecast. This is mitigated in two ways: (1) the flexibility in the planning process to conduct iterations on modeling if deemed necessary, and (2) that investment decisions will not necessarily be made solely based on the high load sensitivity.

To address Blue Planet's and the Joint Parties concerns regarding the high EV sensitivity, see the Companies' response to CA-2 and JP-6, above.

(4) Do Hawaiian Electric's base assumptions around grid-scale PV (including slope and land constraints) and wind, as well as the "Land Constrained" Scenario, adequately capture the range of stakeholder perspectives, and/or provide a reasonable basis for the first round of IGP modeling?

Yes. The Companies believe the sensitivities proposed balances various stakeholder perspectives. Ulupono expressed support for the changes to the grid-scale solar and wind availability assumptions. However as noted in response to PHOW-1, the Companies do not object if in the alternative, a constrained grid-scale solar availability is used as the base assumption as recommended by PHOW.

(5) Are there any issues currently in the "parking lot" that are critical to address in this round of IGP modeling? If so, please suggest how the Commission should address them without significantly slowing the process.

The Companies do not believe any of the parking lot items, if not addressed in this first cycle, will have any significant impact on the ultimate result, especially when considering the bookend analysis being performed. As noted in the August Update, in some cases, the state of technology or modeling tools are areas that are still in development within the industry which also inhibits the ability to define modeling inputs to properly characterize the technology. Additionally, data required to address some of parking lot items may not currently exist and require further evaluation on the viability and methodology of implementation in future IGP cycles.

Additionally, none of the Parties or stakeholders in the STWG provided comments suggesting that any of the parking lot items need to be addressed in the first cycle.

(6) Are the assumptions, data sources, and variables for each sensitivity and scenario clearly presented and explained?

Yes. The Company has provided Excel workbooks that explain the assumptions and data sources being used for each sensitivity and scenario. Additionally, none of the Parties' provided comments expressing concerns on this topic.

(7) Do the assumptions regarding future DER programs represent a reasonable best estimate for this round of IGP? If not, please suggest alternative assumptions.

The Companies spent considerable time on this topic through the STWG and individual meetings with stakeholders. Many of the inputs that drive the forecast were provided by stakeholders to develop revised base, low, and high DER forecasts representing best estimates of future DER programs.

As noted above, many of the Joint Parties' concerns were clarified herein. Further the Joint Parties recognized "significant improvements to the DER forecast assumptions" at page 9

of their comments. There does not appear to be any significant concerns raised by the Joint Parties. Moreover, to the extent that the Joint Partis have significant concerns, they have not proposed an alternative forecast for consideration or use in the first round of IGP.

(8) In the August IGP Update, Hawaiian Electric proposed a modification to the bookend scenarios, replacing the higher and lower customer technology adoption bookends with high and low load bookends. Do these high and low load bookend scenarios provide a reasonable and valuable structure for assessing future grid needs and solutions?

Yes. The modifications made by the Companies are consistent with TAP recommendations as laid out in the Companies response to CA-2, above. As noted throughout this document, the proposed modeling framework allows for flexibility to conduct modeling iteration in consultation with stakeholders. Also, see the Companies' response to JP-12.

(9) Are the assumptions Hawaiian Electric used to develop the energy efficiency forecasts clearly identified and explained, and do they provide a sound basis to evaluate forthcoming energy efficiency supply curves?

Yes. The assumptions used in the energy efficiency forecast development were described in the August Update. These forecasts utilize the scenarios and data developed by AEG in their market potential study. The energy efficiency supply curves will be evaluated under the energy efficiency freeze forecast to assess which bundles are selected as cost effective relative to existing energy efficiency. The base case, low and high load bookends will assume the base, high, and low energy efficiency forecasts and not apply the energy efficiency supply curves to avoid double counting the impacts of those measures. Further details of the energy efficiency forecasts and their use with the supply curves were discussed in the responses to PUC-IR-6, PUC-IR-7, and PUC-IR-8. On September 7, 2021,[62] AEG presented preliminary energy

[62] Available at, https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/stakeholder_technical/20210907_stwg_meeting_presentation_materials.pdf

efficiency supply curves, and on September 20, 2021, the Companies posted to its website, Excel sheets containing the details of the supply curve bundles and costs.[63]

(10) Are there any unexplained discrepancies between the data in the inputs and assumptions Excel workbooks and the inputs and assumptions submitted in the August IGP Update or discussed in prior stakeholder meetings?

Due to voluminous data, the Companies have worked to minimize any discrepancies. On August 19, 2021, the Companies re-issued the workbooks with minor corrections. If any other discrepancies are found the Companies will re-issue updated versions in the future.

(11) Is there any outstanding stakeholder feedback that has not been reasonably considered or addressed in the August IGP Update?

No. The Companies believe that there is no outstanding stakeholder feedback that has not been reasonably considered or addressed. While the Companies provide responses to comments received from the Consumer Advocate, Ulupono, COH, PHOW, and the Joint Parties herein, the responses are intended to clarify issues that have already been extensively discussed through the Companies' stakeholder engagement processes.

IV. CONCLUSION

The Hawaiian Electric Companies appreciate the opportunity to respond to the party comments and Commission questions and look forward to the next steps in this proceeding.

DATED: Honolulu, Hawai‘i, September 21, 2021.

By /s/ Rod S. Aoki
Rod S. Aoki

Attorney for

HAWAIIAN ELECTRIC COMPANY, INC.
MAUI ELECTRIC COMPANY, LIMITED
HAWAII ELECTRIC LIGHT COMPANY, INC.

[63] Available at, https://www.hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning/stakeholder-engagement/key-stakeholder-documents

IGP Base (Reference) Case
Hawaiian Electric % of EV Saturation

	Oahu	Hawaii Island	Maui	Molokai	Lanai
2020	1.46%	0.42%	0.72%	0.92%	1.98%
2021	1.77%	0.53%	0.96%	1.04%	2.18%
2022	2.15%	0.68%	1.33%	1.15%	2.41%
2023	2.60%	0.90%	1.78%	1.36%	2.67%
2024	3.12%	1.26%	2.34%	1.62%	2.97%
2025	3.73%	1.80%	3.21%	1.92%	3.32%
2026	4.44%	2.51%	4.44%	2.27%	3.73%
2027	5.25%	3.34%	6.12%	2.67%	4.22%
2028	6.18%	4.32%	7.72%	3.13%	4.72%
2029	7.22%	5.27%	9.28%	3.64%	5.21%
2030	8.39%	6.28%	11.38%	4.23%	5.93%
2031	9.69%	7.49%	13.99%	4.88%	6.75%
2032	11.14%	8.77%	17.07%	5.60%	7.72%
2033	12.74%	10.18%	20.40%	6.41%	8.83%
2034	14.51%	11.66%	23.74%	7.30%	10.13%
2035	16.43%	13.39%	26.91%	8.38%	11.62%
2036	18.31%	15.12%	30.28%	9.61%	13.30%
2037	20.47%	17.03%	33.65%	11.01%	15.18%
2038	23.02%	19.10%	37.21%	12.53%	17.28%
2039	26.01%	21.40%	40.64%	14.16%	19.61%
2040	29.48%	23.91%	44.03%	16.23%	22.17%
2041	33.54%	26.50%	47.38%	18.58%	25.00%
2042	37.70%	29.48%	50.54%	21.15%	28.09%
2043	42.01%	32.67%	53.49%	23.91%	31.47%
2044	46.60%	36.03%	56.49%	26.79%	35.14%
2045	51.55%	39.56%	59.30%	29.77%	39.02%
2046	56.67%	43.40%	62.12%	32.78%	42.85%
2047	61.81%	47.40%	64.84%	35.80%	46.66%
2048	66.47%	51.40%	67.46%	38.77%	50.38%
2049	70.42%	55.31%	70.01%	41.64%	53.98%
2050	73.63%	59.46%	72.54%	44.38%	57.38%

IGP Base (Reference) Case
Hawaiian Electric Number of EVs

	Oahu	Hawaii Isla	Maui	Molokai	Lanai
2020	9323	796	1156	37	51
2021	11345	1018	1533	42	56
2022	13782	1333	2143	47	62
2023	16680	1789	2873	56	69
2024	20106	2522	3804	66	77
2025	24116	3650	5228	79	87
2026	28756	5138	7276	93	98
2027	34086	6915	10066	110	111
2028	40179	9017	12758	129	124
2029	47093	11065	15416	151	138
2030	54881	13231	18999	176	158
2031	63598	15935	23480	203	180
2032	73301	18813	28780	234	207
2033	84051	22004	34538	268	237
2034	95903	25392	40384	306	273
2035	108927	29367	45967	352	315
2036	121634	33399	51970	405	361
2037	136351	37861	58015	465	414
2038	153802	42754	64476	530	473
2039	174260	48193	70763	600	538
2040	198017	54171	77031	690	611
2041	225858	60384	83272	792	691
2042	254479	67570	89206	904	780
2043	284215	75272	94796	1023	876
2044	315923	83447	100490	1150	982
2045	350243	92090	105860	1280	1094
2046	385724	101518	111257	1413	1206
2047	421490	111405	116490	1546	1318
2048	453999	121342	121546	1678	1428
2049	481696	131155	126476	1807	1535
2050	504068	141362	131219	1930	1637

IGP High Case - 100% ZEV by 2045 (Based on Transcending Oil)
Hawaiian Electric % of EV Saturation

	Oahu	Hawaii Island	Maui	Molokai	Lanai
2020	2.00%	2.00%	2.00%	2.00%	2.00%
2021	3.00%	3.00%	3.00%	3.00%	3.00%
2022	5.50%	5.50%	5.50%	5.50%	5.50%
2023	8.00%	8.00%	8.00%	8.00%	8.00%
2024	13.00%	13.00%	13.00%	13.00%	13.00%
2025	18.00%	18.00%	18.00%	18.00%	18.00%
2026	24.00%	24.00%	24.00%	24.00%	24.00%
2027	30.00%	30.00%	30.00%	30.00%	30.00%
2028	36.00%	36.00%	36.00%	36.00%	36.00%
2029	42.00%	42.00%	42.00%	42.00%	42.00%
2030	48.50%	48.50%	48.50%	48.50%	48.50%
2031	55.00%	55.00%	55.00%	55.00%	55.00%
2032	61.00%	61.00%	61.00%	61.00%	61.00%
2033	67.00%	67.00%	67.00%	67.00%	67.00%
2034	72.50%	72.50%	72.50%	72.50%	72.50%
2035	78.00%	78.00%	78.00%	78.00%	78.00%
2036	83.00%	83.00%	83.00%	83.00%	83.00%
2037	88.00%	88.00%	88.00%	88.00%	88.00%
2038	91.00%	91.00%	91.00%	91.00%	91.00%
2039	94.00%	94.00%	94.00%	94.00%	94.00%
2040	96.00%	96.00%	96.00%	96.00%	96.00%
2041	98.00%	98.00%	98.00%	98.00%	98.00%
2042	98.50%	98.50%	98.50%	98.50%	98.50%
2043	99.00%	99.00%	99.00%	99.00%	99.00%
2044	99.50%	99.50%	99.50%	99.50%	99.50%
2045	100.00%	100.00%	100.00%	100.00%	100.00%
2046	100.00%	100.00%	100.00%	100.00%	100.00%
2047	100.00%	100.00%	100.00%	100.00%	100.00%
2048	100.00%	100.00%	100.00%	100.00%	100.00%
2049	100.00%	100.00%	100.00%	100.00%	100.00%
2050	100.00%	100.00%	100.00%	100.00%	100.00%

IGP High Case - 100% ZEV by 2045 (Based on Transcending Oil)
Hawaiian Electric Number of EVs

	Oahu	Hawaii Island	Maui	Molokai	Lanai
2020	12769	3823	3192	51	81
2021	19197	5808	4808	77	122
2022	35274	10781	8853	142	224
2023	51418	15869	12927	207	327
2024	83751	26080	21097	338	532
2025	116253	36501	29345	470	739
2026	155368	49171	39293	629	988
2027	194666	62072	49324	789	1237
2028	234228	75172	59480	950	1488
2029	274041	88165	69751	1112	1741
2030	317359	102236	80966	1289	2015
2031	360884	116955	92276	1467	2290
2032	401307	130798	102828	1633	2546
2033	441902	144806	113458	1801	2803
2034	479348	157884	123310	1955	3040
2035	516970	171097	133243	2111	3278
2036	551517	183337	142434	2255	3496
2037	586304	195687	151740	2399	3716
2038	607957	203669	157687	2490	3851
2039	629725	211698	163689	2581	3987
2040	644841	217506	167970	2645	4082
2041	659952	223331	172248	2710	4176
2042	664915	225733	173866	2733	4207
2043	669801	228110	175447	2757	4238
2044	674624	230462	176997	2781	4269
2045	679383	232787	178516	2804	4300
2046	680661	233919	179103	2814	4310
2047	681869	235015	179655	2824	4320
2048	683001	236078	180172	2834	4330
2049	684039	237122	180644	2843	4339
2050	684610	237731	180894	2853	4349

IGP Low Case (Also Presented as Example Low Cases for Oahu, Hawaii Island and Maui at January 29, 2020 FAWG)
Hawaiian Electric % of EV Saturation

	Oahu	Hawaii Island	Maui	Molokai	Lanai
2020	1.17%	0.38%	0.67%	1.82%	0.84%
2021	1.35%	0.47%	0.87%	1.98%	0.94%
2022	1.56%	0.59%	1.13%	2.05%	0.98%
2023	1.80%	0.77%	1.43%	2.15%	1.10%
2024	2.07%	0.92%	1.80%	2.27%	1.24%
2025	2.39%	1.10%	2.32%	2.40%	1.39%
2026	2.75%	1.31%	3.04%	2.55%	1.55%
2027	3.18%	1.63%	3.95%	2.73%	1.72%
2028	3.67%	2.02%	4.79%	2.93%	1.94%
2029	4.23%	2.50%	5.58%	3.13%	2.19%
2030	4.88%	3.09%	6.61%	3.44%	2.45%
2031	5.63%	3.78%	7.85%	3.79%	2.73%
2032	6.50%	4.61%	9.25%	4.18%	3.04%
2033	7.50%	5.55%	11.05%	4.79%	3.47%
2034	8.66%	6.69%	12.86%	5.49%	3.95%
2035	9.99%	7.86%	14.58%	6.30%	4.54%
2036	11.54%	9.23%	16.41%	7.21%	5.21%
2037	13.32%	10.71%	18.24%	8.23%	5.97%
2038	15.39%	12.42%	20.18%	9.37%	6.80%
2039	17.77%	14.22%	22.45%	10.83%	7.82%
2040	20.52%	16.28%	24.74%	12.46%	9.12%
2041	23.34%	18.41%	27.65%	14.59%	10.84%
2042	26.46%	20.80%	30.51%	16.96%	12.77%
2043	29.96%	23.22%	33.28%	19.58%	14.87%
2044	33.74%	25.92%	36.18%	22.50%	17.16%
2045	37.88%	28.92%	38.98%	25.65%	19.57%
2046	42.21%	31.88%	41.26%	28.47%	21.78%
2047	46.61%	35.13%	43.50%	31.30%	24.02%
2048	50.64%	38.72%	45.66%	34.11%	26.24%
2049	54.09%	42.67%	47.79%	36.85%	28.43%
2050	56.90%	47.02%	49.91%	39.48%	30.53%

IGP Low Case (Also Presented as Example Low Cases for Oahu, Hawaii Island and Maui at January 29, 2020 FAWG)
Hawaiian Electric Number of EVs

	Oahu	Hawaii Island	Maui	Lanai	Molokai
2020	7,490	700	1,062	45	33
2021	8,657	887	1,392	49	37
2022	9,997	1,135	1,823	52	39
2023	11,540	1,486	2,316	55	44
2024	13,336	1,798	2,915	58	50
2025	15,408	2,176	3,786	62	57
2026	17,818	2,630	4,971	66	63
2027	20,609	3,301	6,500	72	71
2028	23,848	4,133	7,915	77	80
2029	27,595	5,171	9,268	83	91
2030	31,948	6,462	11,033	92	102
2031	36,963	7,933	13,164	101	114
2032	42,769	9,721	15,601	112	127
2033	49,468	11,810	18,711	129	146
2034	57,230	14,346	21,873	148	166
2035	66,229	16,986	24,902	171	191
2036	76,669	20,103	28,162	196	220
2037	88,768	23,489	31,453	225	253
2038	102,793	27,431	34,973	257	288
2039	119,028	31,626	39,090	298	333
2040	137,804	36,440	43,282	344	389
2041	157,182	41,457	48,599	405	463
2042	178,606	47,137	53,852	472	547
2043	202,693	52,925	58,974	547	638
2044	228,747	59,402	64,354	630	738
2045	257,340	66,645	69,579	721	843
2046	287,287	73,841	73,905	803	941
2047	317,834	81,790	78,143	886	1,039
2048	345,882	90,568	82,275	968	1,138
2049	369,971	100,270	86,337	1,050	1,236
2050	389,576	110,996	90,285	1,128	1,330

Example High Cases (as Presented at January 29, 2020 FAWG for Oahu, Hawaii Island and Maui)
Hawaiian Electric % of EV Saturation

	Oahu	Hawaii Island	Maui	Molokai	Lanai
2020	2.09%	0.54%	1.14%	3.12%	1.45%
2021	2.85%	0.74%	1.51%	3.43%	1.63%
2022	3.67%	1.01%	2.12%	3.84%	1.83%
2023	4.45%	1.38%	3.14%	4.72%	2.41%
2024	5.41%	1.84%	4.10%	5.19%	2.84%
2025	6.58%	2.45%	5.58%	5.77%	3.34%
2026	7.69%	3.17%	6.92%	5.81%	3.53%
2027	8.95%	4.11%	9.01%	6.21%	3.93%
2028	10.36%	5.17%	11.34%	6.93%	4.59%
2029	11.92%	6.50%	13.62%	7.65%	5.34%
2030	13.65%	8.01%	16.68%	8.69%	6.19%
2031	15.54%	9.91%	19.80%	9.55%	6.90%
2032	17.62%	11.79%	24.13%	10.91%	7.92%
2033	19.88%	13.88%	28.81%	12.48%	9.05%
2034	22.35%	15.90%	33.53%	14.31%	10.30%
2035	25.00%	18.25%	38.01%	16.42%	11.83%
2036	27.26%	20.61%	42.79%	18.79%	13.58%
2037	29.81%	23.21%	46.73%	21.09%	15.30%
2038	32.74%	26.04%	50.84%	23.61%	17.12%
2039	36.11%	29.17%	54.75%	26.41%	19.07%
2040	39.92%	32.59%	58.57%	29.50%	21.60%
2041	44.26%	35.94%	62.32%	32.88%	24.44%
2042	48.94%	39.57%	65.82%	36.59%	27.55%
2043	54.06%	43.39%	69.09%	40.64%	30.88%
2044	59.45%	47.39%	72.37%	45.02%	34.32%
2045	65.23%	51.55%	75.44%	49.64%	37.87%
2046	71.13%	55.52%	78.49%	54.14%	41.42%
2047	77.02%	59.67%	81.41%	58.58%	44.95%
2048	82.30%	64.08%	84.21%	62.90%	48.39%
2049	86.75%	67.96%	86.92%	67.02%	51.70%
2050	90.35%	71.91%	89.58%	70.85%	54.80%

Example High Cases (as Presented at January 29, 2020 FAWG for Oahu, Hawaii Island and Maui)
Hawaiian Electric % of EV Saturation

	Oahu	Hawaii Island	Maui	Lanai	Molokai
2020	13,356	997	1,825	77	56
2021	18,236	1,395	2,414	85	64
2022	23,518	1,932	3,413	97	73
2023	28,629	2,676	5,079	120	97
2024	34,865	3,605	6,659	133	115
2025	42,471	4,862	9,098	149	136
2026	49,804	6,362	11,328	151	145
2027	58,053	8,327	14,813	163	162
2028	67,419	10,588	18,736	183	190
2029	77,776	13,451	22,615	202	221
2030	89,295	16,734	27,840	231	257
2031	101,944	20,802	33,217	255	288
2032	115,889	24,844	40,677	293	331
2033	131,109	29,514	48,784	336	379
2034	147,764	34,083	57,029	387	433
2035	165,663	39,446	64,926	446	498
2036	181,138	44,889	73,427	512	573
2037	198,586	50,914	80,580	576	648
2038	218,761	57,524	88,104	648	727
2039	241,898	64,872	95,337	727	811
2040	268,130	72,950	102,483	815	921
2041	298,076	80,936	109,532	912	1,044
2042	330,351	89,645	116,190	1,018	1,180
2043	365,738	98,889	122,432	1,135	1,325
2044	403,098	108,606	128,740	1,261	1,476
2045	443,145	118,789	134,666	1,395	1,632
2046	484,161	128,601	140,572	1,527	1,789
2047	525,146	138,909	146,263	1,657	1,945
2048	562,117	149,897	151,728	1,785	2,099
2049	593,421	159,709	157,019	1,909	2,247
2050	618,560	169,762	162,043	2,025	2,387

Residential Minimum Equipment Standards

	2018	2019	2020	2021	2022	2023	2024	2025
Central AC	SEER 14					SEER 15		
Room AC	CEER 10.9							
Ductless Mini Split AC	SEER 14							
Water Heater (<= 55 Gal)	EF 0.945 - Federal Standard							
Water Heater (> 55 Gal)	EF 2.00 - Federal Standard							
General Service Lighting	EISA Compliant (18.6 lm/W)		EISA Compliant (45 lm/W)					
Linear Lighting	T8 - F32 (80.0 lm/W lm/W system)							
Exempted Lighting	Incandescent (9.8 lm/W)							
Refrigerator	2014 Federal Standard							
Freezer	2014 Federal Standard							
Clothes Washer	March 2015 Fed Minimum Std IMEF = 1.66							
Clothes Dryer	2015 Fed Standard (UCEF 2.73)							
Dishwasher	Standard 2013 (180-307 kWh)							
Personal Computers	Standard (Non-ENERGY STAR)			ENERGY STAR				
Monitor	Standard (Non-ENERGY STAR)			ENERGY STAR				
Laptops	Standard (Non-ENERGY STAR)			ENERGY STAR				
Set-top Boxes/DVRs	2017 Manufacturer's Agreement Standard							
Electric Vehicle Charger	Level 2 Standard (Non-ENERGY STAR)							
Pool Pump	Standard Single-Speed			Variable Speed Pump				

Commercial Minimum Equipment Standards

<table>
<tr><th></th><th>2018</th><th>2019</th><th>2020</th><th>2021</th><th>2022</th><th>2023</th><th>2024</th><th>2025</th></tr>
<tr><td>Air-Cooled Chiller</td><td colspan="8">ASHRAE 90.1-2016 Baseline (IPLV 0.976 kW/ton)</td></tr>
<tr><td>Water-Cooled Chiller</td><td colspan="8">ASHRAE 90.1-2016- COP 5.78 (IPLV 0.50 kW/ton)</td></tr>
<tr><td>RTU</td><td colspan="5">IEEC 2015 IEER 12.9</td><td colspan="3">Federal Standard 2023 IEER 14.8</td></tr>
<tr><td>Central AC</td><td colspan="5">SEER 14</td><td colspan="3">SEER 15.0</td></tr>
<tr><td>Room AC</td><td colspan="8">CEER 10.9</td></tr>
<tr><td>Packaged Terminal AC</td><td colspan="8">Federal Standard EER 10.4</td></tr>
<tr><td>Ventilation</td><td colspan="8">Constant Air Volume, 2-Speed VFD</td></tr>
<tr><td>Water Heater</td><td colspan="8">EF 2.00 - Federal Standard</td></tr>
<tr><td>General Service Lighting</td><td colspan="2">EISA Compliant (20.7 lm/W)</td><td colspan="6">EISA Compliant (45 lm/W)</td></tr>
<tr><td>Exempted Lighting</td><td colspan="8">Incandescent (16.2 lm/W)</td></tr>
<tr><td>Linear Lighting</td><td colspan="8">T8 - F32 Standard</td></tr>
<tr><td>High-Bay/Area Lighting</td><td colspan="8">Metal Halide (51.2 lm/W)</td></tr>
<tr><td>Walk-in Refrigerator/Freezer</td><td colspan="2">Current Standard</td><td colspan="6">Standard (2020)</td></tr>
<tr><td>Open Display Case</td><td colspan="2">1,047 kWh/ft</td><td colspan="6">982 kWh/ft</td></tr>
<tr><td>Vending Machine</td><td colspan="2">Standard</td><td colspan="6">2020 Standard</td></tr>
<tr><td>Desktop Computer</td><td colspan="3">Standard (Non-ENERGY STAR)</td><td colspan="5">ENERGY STAR</td></tr>
<tr><td>Laptop</td><td colspan="3">Standard (Non-ENERGY STAR)</td><td colspan="5">ENERGY STAR</td></tr>
<tr><td>Monitor</td><td colspan="3">Standard (Non-ENERGY STAR)</td><td colspan="5">ENERGY STAR</td></tr>
<tr><td>Non-HVAC Motors</td><td colspan="8">Standard (NEMA Premium)</td></tr>
<tr><td>Pool Pump</td><td colspan="3">Standard Single-Speed</td><td colspan="5">Variable Speed Pump</td></tr>
<tr><td>Clothes Washer</td><td colspan="8">MEF 1.87</td></tr>
<tr><td>Clothes Dryer</td><td colspan="8">2015 Fed Standard (UCEF 2.73)</td></tr>
<tr><td>Electric Vehicle Charger</td><td colspan="8">Level 2 Standard (Non-ENERGY STAR)</td></tr>
</table>

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DATED: Honolulu, Hawai'i, September 21, 2021

HAWAIIAN ELECTRIC COMPANY, INC.

/s/ Marisa K. Chun
Marisa K. Chun

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