January 31, 2022

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

Dear Commissioners:

Subject: Adequacy of Supply Report
Hawaiian Electric Company, Inc.

The following information is respectfully submitted in accordance with paragraph 5.3.a of General Order No. 7, which states:

> *The generation capacity of the utility's plant, supplemented by electric power regularly available from other sources, must be sufficiently large to meet all reasonably expectable demands for service and provide a reasonable reserve for emergencies. A Statement shall be filed annually with the Commission within 30 days after the close of the year indicating the adequacy of such capacity and the method used to determine the required reserve capacity which forms the basis for future requirements in generation, transmission, and distribution plant expansion programs required under Rule 2.3h.1.*

2022 Adequacy of Supply Report Summary

- Hawaiian Electric Company, Inc.'s ("Hawaiian Electric" or the "Company") 2022 Adequacy of Supply employs an Energy Reserve Margin criteria, developed to review adequacy of supply in all hours of the year vs. during the peak hour of the day or peak day of the year and incorporates the reliability contribution of variable and energy-limited resources, such as energy storage, and duration limited grid services, such as demand response resources.

- Hawaiian Electric's Energy Reserve Margin target is satisfied from 2022 through 2026 with the addition of Hawaiian Electric's planned generation and storage resource additions. New resources planned for O‘ahu are anticipated to meet Energy Reserve Margin targets to mitigate the expiration of AES power purchase agreement.

- The adjusted peak load experienced on O‘ahu in 2021 was 1,100 MW-net and was served by Hawaiian Electric's total capability of 1,744 MW-net, including firm power purchases. This represents a firm capacity generation reserve margin of approximately 62% over the 2021 adjusted system net peak.

1.0 Peak Demand and System Capability in 2021

The adjusted peak load experienced on O‘ahu in 2021 was 1,100 MW-net and was served by Hawaiian Electric's total capability of 1,744 MW-net, including firm power purchases. This represents a firm capacity generation reserve margin of approximately 62%[1] over the 2021 adjusted system net peak.

The system peak occurred on Wednesday, November 17, 2021 at approximately 6:26 p.m., and was 1,072 MW-net based on net Hawaiian Electric generation, net purchased power generation, the peak reduction benefits of energy efficiency programs, and with several co-generators[2] operating at the time. Had these cogenerating units not been operating, the 2021 system peak would have been approximately 1,100 MW-net.

Hawaiian Electric's 2021 total generating capability of 1,744 MW-net includes 456.5 MW net of firm power purchased from (1) Kalaeloa Partners, L.P. ("KPLP"), (2) AES Hawaii, Inc. ("AES"), and (3) H-POWER.

At times during 2021, Hawaiian Electric received energy from seventeen variable generation energy producers. Since these contracts are not for firm capacity, they are not reflected in Hawaiian Electric's total firm generating capability.

2.0 Criteria to Evaluate Hawaiian Electric's Adequacy of Supply

Hawaiian Electric's capacity planning criteria are applied to determine the adequacy of supply and whether or not there is enough generating capacity on the system. Hawaiian Electric's capacity planning criteria takes into account that Hawaiian Electric must provide for its own backup generation since, as an island utility, it cannot import emergency power from a neighboring utility.

The function of a planning criteria is to establish guidelines to manage the risk of insufficient generation capability from a diverse mix of generating resources available to the system in long-range generation expansion studies. Resource plan development is evaluated based on a consistent guideline or criteria to provide adequate generation to meet customer demand, with reasonable reserves to account for routine maintenance or overhauls of units, unexpected outages

[1] The total capability value used in the calculation of this reserve margin does not account for units not available due to maintenance outages, forced outages or derates in unit capacities. The reserve margin calculation takes into account the approximately 21 MW of interruptible load (grid services of capacity reduction included) that may be available at system peak. In actual real-time operations, reserves may be reduced due to maintenance, forced outages or deratings.

[2] At the time of the peak, certain units at Par Hawaii, Sheraton and Pearl Harbor were generating about 28 MW of power for use at their sites.

of generating units, growth in customer demand over time, and possibilities of higher than forecasted instantaneous peak demand.

With the increasing quantities of variable renewable wind and solar resources, and future energy storage additions to the system, an Energy Reserve Margin criteria was developed considering the dynamic nature of variable resources and limited duration storage.[3] For the purposes of this adequacy of supply report, Hawaiian Electric used this planning criteria.

2.1. Energy Reserve Margin

The Energy Reserve Margin is the percentage which the system capacity must exceed the system load in each hour for planning objectives. With the increasing quantities of variable renewable wind and solar resources, this capacity planning criteria is intended to account for current and future variable generation resources considering the dynamic nature of energy provided by wind, PV and implications of limited duration storage. The hourly evaluation of available energy allows for statistical representation of the impact of variable and finite resources at all hours of the day in the assessment of energy margin. The Energy Reserve Margin for O‘ahu is 30%, to provide reasonable reliability reserve to address some level of contingencies, forecast errors, and uncertainties inherent in the assumptions and methodology.

2.2. Other Considerations in Determining the Timing of Unit Additions

The need for new generation is not based solely on the application of the criteria previously mentioned. As capacity needs become imminent, it is essential that Hawaiian Electric consider additional factors to ensure timely installation of generation capacity necessary to meet its customers' energy needs.

Other near-term considerations may include:

1. The current condition and rated capacity of existing units;
2. Required power purchase obligations and contract terminations;
3. The uncertainties surrounding non-utility generation resources;
4. The uncertainties surrounding new energy and generation resources;

[3] Refer to Appendix C (page 102) of Hawaiian Electric's Integrated Grid Planning Grid Needs Assessment & Solution Evaluation Methodology filed November 5, 2021: https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/20211105_grid_needs_assessment_methodology_review_point_book_1.pdf

5. Transmission system considerations;
6. Meeting environmental compliance standards; and
7. System stability considerations for Hawaiian Electric's isolated electrical system.

While meeting the planning criteria implies a reasonable adequacy of supply, it is not equivalent to a guaranteed supply. As firm capacity resources are displaced to accommodate variable renewable energy, resource planning may need to include resource characteristics to mitigate adequacy of supply risks by having large amounts of offline reserves. This may include consideration of minimum fast-start capability and/or means to curtail demand on short notice.

3.0 Key Inputs to the 2022 Adequacy of Supply Analysis

In the application of Hawaiian Electric's capacity planning criteria that are used to determine its adequacy of supply, the inputs drive the results. Key inputs are described in the following sections.

3.1. Period Under Review

This report review covers the period 2022 to 2026.

3.2. June 2021 Sales and Peak Forecast

In June 2021 a sales and peak forecast ("June 2021 S&P forecast") was developed which was subsequently approved by the Company for future planning purposes and used for this analysis.

The June 2021 S&P forecast began with the development of the energy forecast (i.e., sales forecast) by rate class (residential, small, medium and large commercial and street lighting) and by layer (underlying load forecast and adjusting layers – energy efficiency, distributed energy resources, and electrification of transportation). The underlying load forecast is driven primarily by the economy, weather, electricity price, and known adjustments to large customer loads and is informed by historical data, structural changes, and historical and future disruptions. The impacts of energy efficiency ("EE"), distributed energy resources ("DER"), primarily photovoltaic systems with and without storage (i.e., batteries), and electrification of transportation (light duty electric vehicles ("EV") and electric buses ("eBus"), collectively "EoT") were layered onto the underlying sales outlook to develop the sales forecast at the customer level.

The sales and peak forecasts used for the analysis herein is the result of the methodology described above and the continued impacts of the COVID-19 pandemic. In 2021, the COVID-19 pandemic continued to disrupt global travel, local resident behavior, economic activity and as a result, electricity consumption, with improvements resulting from the widespread distribution of vaccines. Electricity usage continued to be impacted, although in different ways depending on the sector. The economic outlook from the University of Hawai‘i Economic Research Organization ("UHERO"), shows continued recovery in key economic drivers (i.e., visitor arrivals and jobs) but a return to pre-pandemic levels does not occur in the forecast period.

The forecast is the result of the above-described contributing factors and reflects the Company's most current outlook for customer energy demand for the next five years.

In addition, the forecast includes the impact of the Emergency Demand Response Program and Scheduled Dispatch Program Rider from customer-sided energy storage systems during the peak period (aka, "Battery Bonus" program). Based on its current trend as of January 14, 2022, the Company assumes the Battery Bonus program will have an enrollment of 12 MW by September 2022 and ultimately achieve 16.5 MW by June 2023, which is the last month to enroll in the program.

Figure 1 below illustrates Hawaiian Electric's historical system peaks and compares them to the forecasts used in the 2021 and 2022 Adequacy of Supply analyses.

Figure 1: Recorded Peaks and Future Year Projections

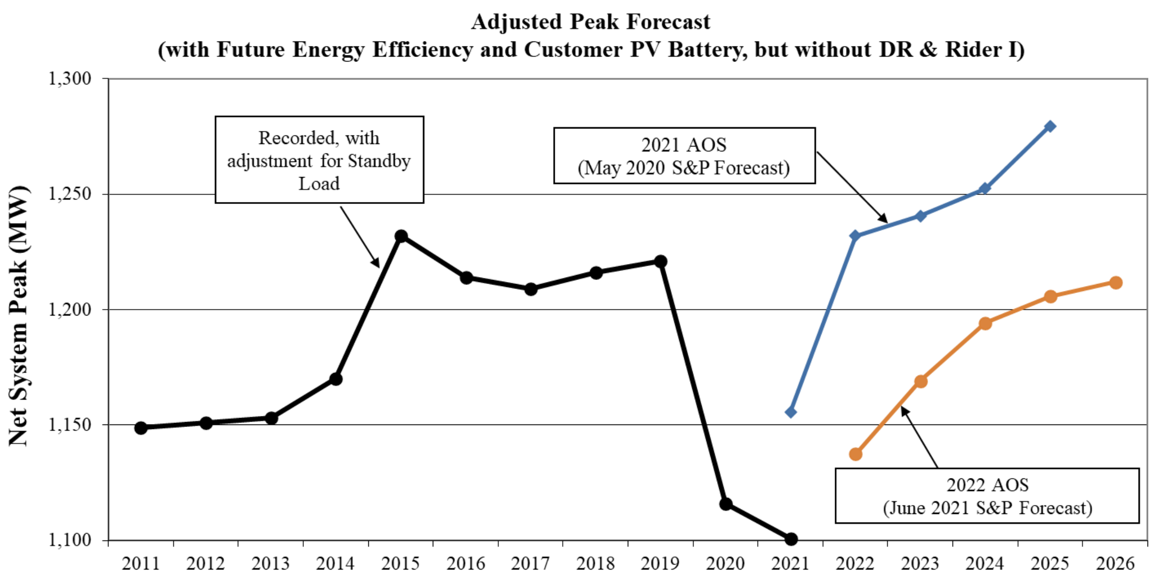

Table 1 below provides the recorded peaks from 2011 and the forecast used in Hawaiian Electric’s 2022 Adequacy of Supply analysis.

Table 1: Recorded Peaks and Future Year Projections

Net System Peak (MW) (with Future Energy Efficiency and Customer PV Battery, but without DR & Rider I)			
Year	Actual	Actual Adj for Standby Load	2022 AOS June 2022 S&P Forecast
2011	1,141	1,149	
2012	1,141	1,151	
2013	1,144	1,153	
2014	1,165	1,170	
2015	1,206	1,232	
2016	1,192	1,214	
2017	1,184	1,209	
2018	1,190	1,216	
2019	1,193	1,221	
2020	1,087	1,116	
2021	1,072	1,100	
2022			1,138
2023			1,169
2024			1,194
2025			1,206
2026			1,212

For both the recorded and forecast data (from the June 2021 S&P Forecast), figures reflect an upward (standby) adjustment to account for the potential need to serve certain large customer loads (i.e., Par Hawaii, Sheraton and Pearl Harbor) that are frequently served by their own internal generation. Figure 1 also includes estimated peak reduction benefits of energy efficiency programs and naturally occurring conservation. With the advent of storage technology (i.e., battery energy storage systems (“BESS”)) for the consumer market, impacts of customer-sited PV paired with batteries were included in the peak forecast. As solar capacity continues to grow year over year, daytime loads are projected to be reduced and, all else being equal, the average daily load profile is expected to have a more pronounced difference between daytime and evening peak.

With an operating assumption of BESS charging during the daytime hours, coincident with PV generation, and discharging the stored energy during the system priority peak period, the system peak has been reduced for this type of energy storage operation.

3.3. Projected Peak Reduction Benefits of Demand Response Programs

Hawaiian Electric is committed to pursuing demand response (“DR”) programs and grid services procurements designed to provide cost-effective resource options.

On January 25, 2018, the Commission issued Decision and Order No. 35238, approving the Companies’ Revised DR Portfolio tariff structure framework. The Commission supported the approach of working with aggregators to implement the DR portfolio. In 2019, the Companies signed a multi-year Grid Services Purchase Agreement (“GSPA”) with a third party aggregator. Currently, the Companies are implementing three GSPA contracts that were approved by the Commission on August 9, 2019 and December 31, 2020. Customer enrollment under these GSPA contracts have been delayed by the COVID-19 pandemic, but the Companies are diligently working with the aggregators to catch up in 2022.

On June 9, 2021, the Commission issued an order providing guidance to the third Grid Services RFP filed on February 23, 2021. The proposed Grid Services RFP focused only on O‘ahu and sought 60MW of grid services with focus on capacity reduction in response to the AES coal plant retirement scheduled on September 1, 2022. The Company filed a final draft and received Commission approval to proceed with the RFP on August 3, 2021. The Company made its final selections on November 10, 2021 and commenced negotiations immediately thereafter. The Company is targeting to execute GSPA contracts by end of January 2022 and subsequently request Commission approval.

For the purposes of this analysis, Hawaiian Electric’s adequacy of supply was calculated using estimated DR impacts, including capacity reduction grid service, and customer interruptible load under Rider I as presented in Table 2 below.

Table 2: DR Impacts for Capacity Planning Purposes (MW)

Year	DR	Rider I	Total
2022	31.7	4.3	36.0
2023	31.7	4.3	36.0
2024	31.7	4.3	36.0
2025	31.7	4.3	36.0
2026	31.7	4.3	36.0

On June 8, 2021, the Commission approved a new program, Emergency Demand Response Program ("EDRP"), a battery storage incentive program to dispatch electricity between 6 p.m. to 8 p.m. daily from participating residential and commercial customers. The Company's implementation plan was approved by the Commission on June 30, 2021, and the Company subsequently filed the updated EDRP tariffs on July 1, 2021. As of December 31, 2021, the Utilities have received and approved the applications worth up to 3.47 MW. For the purposes of this analysis, Hawaiian Electric's adequacy of supply was calculated using estimated EDRP impact of 13.5 MW for 2022 and 16.5 MW for 2023. (The Company derived these values for 2022 based on the program's trend in enrollment.)

3.4. Hawaiian Electric Generating Unit Forced Outages

Forced outages and deratings reduce generating unit availability and are accounted for in the EFORd statistic. EFORd, a measure of forced outages and operations in derated conditions, is a subcomponent of generating unit availability. Lower generating unit availability and higher EFORd both contribute to an increase in reserve capacity shortfalls. The definition of EFORd and an example of the application of the EFORd formula is provided in Appendix 2.

Outages for planned work and maintenance will continue to be more frequent and longer in duration than in previous years. Scheduling maintenance will continue to be a challenge for the existing units. As the generating units age,[4] they need to be maintained more often and for longer periods of time. In addition, in response to the changing resources on the system, such as variable generation resources, the generating units are being operated in ways for which they were not designed. Such operation increases the likelihood of unscheduled (forced) outages and operations at derated power levels. Generating units that are shut down unexpectedly generally require immediate maintenance. As resources shift to make the emergency repairs, maintenance outage schedules slip, making maintenance scheduling flexibility difficult. In addition, generating units operating in a derated capacity are generally operated for long periods in a derated state as scheduling a maintenance shutdown to restore the units to full power operations may take a long time.

Table 3 below provides the forward-looking Hawaiian Electric EFORd data by unit. The forward-looking EFORd values are forecasted expectations for planning purposes based on a combination of historical data, experience, and operational judgment. The EFORd assumption generally reflects the four-year average of the specific unit, or group of similar units. EFORd projections are not certain, however, and actual experience may

[4] Hawaiian Electric's generating units (not including the Campbell Industrial Park combustion turbine installed in 2009 and the generating units at the Schofield Generating Station installed in 2018) are between 41 and 75 years old. Firm capacity independent power producer units are between 29 and 31 years old excluding Airport DSG.

differ from the projections. It is difficult to forecast EFORd due to unforeseen conditions of aging units, longer planned maintenance schedules, and the operating stress placed on the units. Refer to Appendix 2 for specific generating unit information on EFORd.

Table 3: Forward-looking EFORd

Waiau 3	25.0%
Waiau 4	25.0%
Waiau 5	12.0%
Waiau 6	9.0%
Waiau 7	10.0%
Waiau 8	10.0%
Waiau 9	8.2%
Waiau 10	8.2%
Kahe 1	10.0%
Kahe 2	10.0%
Kahe 3	10.0%
Kahe 4	10.0%
Kahe 5	7.0%
Kahe 6	7.0%
CIP CT-1	4.2%
Schofield 1	2.0%
Schofield 2	2.0%
Schofield 3	2.0%
Schofield 4	2.0%
Schofield 5	2.0%
Schofield 6	2.0%

3.5. Planned Maintenance Schedules for the Generating Units on the System

Planned outages and maintenance outages reduce generating unit availabilities. The schedules for planned overhaul and maintenance outages change frequently due to unforeseeable findings during outage inspections or to changes in priorities due to unforeseeable problems. When major revisions to planned and/or maintenance outages occur, the Planned Maintenance Schedule is revised. The uncertainty of future maintenance schedules contributes to future planning uncertainty and may influence the magnitude of reserve capacity surplus or shortfalls. A five-year planned maintenance schedule most recently updated in January 2022 was used in this analysis and includes planned maintenance schedules for independent power producers.

3.6. Resource Additions

3.6.1. Firm Capacity Additions

No new firm capacity additions are anticipated from 2022 to 2026.

3.6.2. Non-Firm Additions

In January 2017, Hawaiian Electric filed a letter with the Commission requesting to open a docket to solicit proposals for new renewable dispatchable generation. The Commission subsequently issued Order No. 34856 and opened Docket No. 2017-0352 to receive filings, review approval requests, and resolve disputes, if necessary, related to the plan to proceed with competitive procurement of this generation. Request for Proposals (“RFP”) for the above docket were separated into 2 stages, Stage 1 and Stage 2.

Several variable renewable generation and storage projects have been approved or are under review by the Commission and are in various stages of completion. These are Ho‘ohana Solar 1 (Docket No. 2018-0431), Mililani 1 Solar, LLC (Docket No. 2018-0434), Waiawa Solar Power LLC (Docket No. 2018-0435), AES West O‘ahu (Docket No. 2019-0050), Kapolei Energy Storage (Docket No. 2020-0136), Mountain View Solar (Docket No. 2020-0139), Waiawa Phase 2 Solar (Docket No. 2020-0137), Barbers Point Solar (Docket No. 2020-0143), Mahi Solar (Docket No. 2020-0140) and Kupono Solar (Docket No. 2022-0007).

The Company’s analysis includes 4.99 MW of Community Based Renewable Energy (“CBRE”) from three approved projects.

3.7. Reductions of Firm Generating Capacity

3.7.1. Capacity from AES Hawaii, Inc.

The existing Power Purchase Agreement (“PPA”) with AES expires on September 1, 2022. For the purposes of the 2022 Adequacy of Supply analysis, it is assumed that the capacity from AES is 180 MW through the end of the contract term.

3.8. Capacity from Kalaeloa Partners, L.P., Combined Cycle Unit

The existing PPA with Kalaeloa Partners (“KPLP”) expired on May 23, 2016. The PPA, as amended, automatically extends on a month-to-month basis until either party notifies the other in writing that the negotiations have terminated. On November 24, 2021, the Company submitted an application for approval of an Amended and Restated PPA with KPLP in Docket No. 2021-0188.

For the purposes of the 2022 Adequacy of Supply analysis, it is assumed that the 208 MW of capacity provided by KPLP remains available for the duration of the analysis period.

4.0 Scenario Analysis

4.1. Description of Scenarios

For the Energy Reserve Margin analysis, two scenarios were analyzed. Both scenarios include the planned Stage 1 and Stage 2 variable renewable resources described in Section 3.6.2.

The Moderate scenario takes the expected commercial operations dates of the Stage 1 and Stage 2 projects, and for some of the projects, slightly delayed them 1 to 6 months. While the projects are expected to meet their commercial operations dates, for planning purposes, some dates were adjusted in light of the ongoing pandemic and global supply chain issues.

For the Conservative scenario, some of the expected commercial operations dates of the Stage 1 and Stage 2 projects were delayed 6 months or longer. This was intended to be a more conservative scenario to consider potentially more significant or prolonged impacts from the ongoing pandemic and global supply chain issues.

4.2. Energy Reserve Margin

The results of the Energy Reserve Margin criteria analysis are shown in Table 4. A 30% Energy Reserve Margin target was used for O‘ahu . The results indicate that the Energy Reserve Margin target is satisfied from 2022 through 2026 with the addition of Hawaiian Electric’s planned generation and storage projects.

Table 4: Estimated Energy Reserve Margin Shortfall Hours

Number of Hours Below Energy Reserve Margin Target (Pass/Fail Criteria 30%)		
Year	Moderate Scenario	Conservative Scenario
2022	0 (PASS)	0 (PASS)
2023	0 (PASS)	0 (PASS)
2024	0 (PASS)	0 (PASS)
2025	0 (PASS)	0 (PASS)
2026	0 (PASS)	0 (PASS)

Table 5: Estimated Energy Reserve Margin Percentage

Lowest Estimated Hourly Energy Reserve Margin Percentage		
Year	Moderate Scenario	Conservative Scenario
2022	38%	38%
2023	42%	36%
2024	38%	38%
2025	38%	36%
2026	42%	40%

5.0 Mitigation Measures for Near-Term Reserves

The Company is considering mitigation measures in light of declining performance of certain generating units and AES leaving the system in 2022. Contingency Plans and Mitigation Measures were provided in the Company’s O‘ahu Transition Plan Update submitted on January 14, 2022 in Docket No. 2021-0024. These actions include: working with developers to ensure renewable projects are brought online in time for the AES retirement, executing grid service purchase agreements for load reduction grid services, increasing customer participation in the Battery Bonus program, evaluating an opportunity to purchase 20 MW of battery energy storage that recently become available, evaluating further adjustments to the maintenance schedule, expansion of direct load control programs, expanded communication, education and calls to action on energy conservation, among others.

6.0 Conclusion

Energy Reserve Margin criteria results indicate that the Energy Reserve Margin target is satisfied from 2022 through 2026 with the addition of Hawaiian Electric’s planned generation and storage project additions. New resources planned for O‘ahu are anticipated to meet Energy Reserve Margin targets to mitigate the expiration of the AES PPA.

Under differing scenarios, the Energy Reserve Margin criteria may still be satisfied but with varied risk of shortfalls. Because of uncertain risks, such as project delays or higher loads due to faster economic recovery or warmer and more humid weather than forecasted, the Company is developing mitigation measures to increase the surety of adequate capacity through 2026.

Hawaiian Electric recognizes that the environment for resource planning has increased in complexity and uncertainty. Nonetheless, Hawaiian Electric will continue its portfolio approach to meet its obligation to serve, which includes increased renewable energy contributions, energy storage resources, the pursuit of supply side options, and customer program options, as well as continuing to consider other potential options.

Sincerely,

/s/ Kevin M. Katsura

Kevin M. Katsura
Director
Regulatory Non-Rate Proceedings

Attachments

c: Division of Consumer Advocacy (with Attachments)

Table A1:
Projected Firm Capacity Reserve Margins

Year	System Capability at Annual Peak Load (net MW) [A] (I)	System Peak (net MW) [B] (II)	Interruptible Load (net MW) [C] (III)	Reserve Margin (%) [A-(B-C)] / (B-C)
2021	1,744	1,100	21	62%
2022	1,564	1,138	36	42%
2023	1,564	1,169	36	38%
2024	1,472	1,194	36	27%
2025	1,472	1,206	36	26%
2026	1,472	1,212	36	25%

Notes:

I. System Capability includes:
- Hawaiian Electric units at total normal capability in 2021 was 1,279.7 MW-net.
- Airport DSG (8 MW).
- Firm PPAs with a combined net total of 465.5 MW in 2021 from KPLP (208 MW), AES Hawaii (180 MW), and H-POWER (68.5 MW).
- KPLP assumed to continue in service after 2021.
- Schofield Generating Station (“SGS”) (49.4 MW).

II. System Peaks
- The 2022-2026 annual forecasted system peaks are based on Hawaiian Electric’s June 2021 S&P Forecast.
- The forecasted System Peaks for 2022-2026 include the estimated peak reduction benefits of third-party energy efficiency programs.
- The peak for 2022-2026 includes approximately 28 MW of stand-by load.
- The Hawaiian Electric annual forecasted system peak is expected to occur in the second half of the year.

III. Interruptible Load:
Interruptible Load impacts are at the net-to-system level and are approximate impacts at the system peak

Equivalent Demand Forced Outage Rate Definition and Formula

As defined in IEEE Std-762-2006,[5] Section 3.8:

Equivalent Demand Forced Outage Rate (EFORd): A measure of the probability that a generating unit will not be available due to forced outages or forced deratings when there is demand on the unit to generate.

EFORd is defined in the North American Electric Reliability Corporation Generating Availability Data System Data Reporting Instructions,[6] Appendix F as:

$$\text{EFORd} = \frac{[\text{FOHd} + (\text{EFDHd})]}{[\text{SH} + \text{FOHd}]} \times 100\%$$

where

FOHd = f x FOH

EFDHd = (EFDH – EFDHRS) if reserve shutdown events reported, or

= (fp x EFDH) if no reserve shutdown events reported – an approximation.

fp = (SH/AH)

$$f = \left(\frac{1}{r} + \frac{1}{T}\right) \Big/ \left(\frac{1}{r} + \frac{1}{T} + \frac{1}{D}\right)$$

r=Average Forced outage deration = (FOH) / (# of FO occurrences)

D=Average demand time = (SH) / (# of unit actual starts)

T=Average reserve shutdown time = (RSH) / (# of unit attempted starts)

An example of the application of the EFORd formula to Hawaiian Electric's Waiau 9 generating unit in 2012 is shown below:

	Service Hours	Reserve Shutdown Hours	Available Hours				Equivalent Forced Derated Hours	Forced Outage Hours	
Capacity	SH	RSH	AH	Actual Starts	Attempted Starts	Failed Starts	EFDH	FOH	FO Events
53	67	7002.14	7069	26	27	1	0.00	1,067.26	5

=1/(1067/5)	=1/(7002/27)	=1/(67/26)		=0.021397*1067	=67/7069	=0.009416*0		=(22.84/(67+22.84))*100	=(1067/(1067+67))*100
1/r	1/T	1/D	f	fxFOH	fp	fp x EFDH	EFORd x MW	**EFORd**	**EFOR**
0.004685	0.003856	0.390625	0.021397	22.83591142	0.009416	0	1,353.87	**25.54**	**94.1**

[5] https://documents.pub/reader/full/ieee-762-2006

[6] https://www.nerc.com/pa/RAPA/gads/DataReportingInstructions/2022_GADS_DRI.pdf#search=IEEE%20762%202006

Hawaiian Electric Equivalent Demand Forced Outage Rate ("EFORd") Discussion

It is extremely difficult to predict unit-specific EFORd rates, solely based on historical data. Nonetheless, for planning purposes it is necessary to estimate forward-looking EFORd rates. This is accomplished using a blend of historical data, experience, judgment, issues affecting aging generation including operation outside of original design parameters, and resource constraints. The forwarded looking EFORd are based on the four-year EFORd averages for unit types with some exceptions as noted below. The four-year average is appropriate because the majority of the flexible operations (low load operation and higher ramp rates) started in 2016. The units forward looking EFORd are as follows:

<u>Kahe 1-4 and Waiau 7-8:</u> 10%

The above units are all "small" reheat units operating under the same mission profile. These aging units range from 50 to 59 years of age and operate with higher ramp rates, operate under the variable pressure/low load operation, and cycle or will cycle when necessary. The actual combined 4 year average EFORd for these units is 14.2% but was adjusted down to 10% due to one time events and impacts on maintenance resulting from the COVID-19 pandemic in 2020.

<u>Kahe 5-6:</u> 7%

The above "large" reheat units operate under the same mission profile (load following from base to full load). These aging units range from 41 to 48 years of age are base loaded, operate many hours near minimum, and operate with enhanced ramp rates. The actual 4 year combined average EFORd for these units is 13%. EFORd was adjusted due to impacts on maintenance resulting from the COVID-19 pandemic in 2020.

<u>Waiau 3 & 4:</u> 25%

These 72 and 75 year old units operates as a "limited use" unit. The units undergo large amount of starts per year which contributes to wear and tear. The unit does not undergo normal overhauls or extensive maintenance.

<u>Waiau 5:</u> 12%

This 63 year old unit still starts over 200 times per year. The unit has chronic problems associated with an aging integrated steam chest. Its current forced outage rates are expected to remain the same. The actual four-year average EFORd is 22%. The unit is not averaged with other units because it is in materially different condition. Turbine steam chest leaks have been impacting unit reliability since 2017. Permanent repairs were completed in 2020 and expected to result in improved reliability. Therefore, EFORd has been adjusted accordingly.

<u>Waiau 6:</u> 9%

This 61 year old unit still starts over 200 times per year. The actual 4 year average EFORd is 9%. Waiau 6 was not averaged with the "like unit" (Waiau 5) because of the material condition described under Waiau 5 above.

Waiau 9-10: 8.2%

The above combusting turbines are 49 years old and experience hundreds of starts per year. The actual 4 year average EFORd for the two units is 11.3%. EFORd adjusted to account for the impacts to maintenance resulting from the COVID-19 pandemic in 2020 and material condition improvements in 2021.

CIP CT-1: 4.2%

This 13 year old unit has been experienced over 300 starts per year. 4.2% EFORd represents the four-year average EFORd. CT-1 is a unique unit type and therefore not averaged with other units.

SGS Units 1-6: 2.0%

SGS is a new generating station commissioned in June 2018.

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