BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAIʻI

In the Matter of the Application of MAUI ELECTRIC COMPANY, LTD. For Approval to Commit Funds in Excess of $2,500,000 for the Purchase and Installation of Item MZ.005002, Waena Battery Energy Storage System Project, and to Recover Costs through the Major Project Interim Recovery Adjustment Mechanism.	DOCKET NO.

APPLICATION OF MAUI ELECTRIC COMPANY, LTD.

VERIFICATION

EXHIBITS 1-9

and

CERTIFICATE OF SERVICE

Joseph P. Viola
Vice President, Regulatory Affairs
Hawaiian Electric Company, Inc.

Vice President
Maui Electric Company, Limited

P.O. Box 2750
Honolulu, Hawaiʻi 96840

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APPLICATION

TO THE HONORABLE PUBLIC UTILITIES COMMISSION
OF THE STATE OF HAWAIʻI:

MAUI ELECTRIC COMPANY, LTD. (hereinafter "Maui Electric" or the "Company") respectfully requests Commission approval to commit funds in excess of $2,500,000 (currently estimated at $60,003,000) for its Waena Battery Energy Storage System ("BESS") Project (the "Project" or "Waena BESS Project").

The Company requests a Commission Decision approving the commitment of funds for the Project by mid-February 2021, to meet the Project schedule and the Guaranteed Commercial Operations Date (GCOD) of April 28, 2023. Maui Electric Company needs to start engineering in February 2021 to meet the GCOD.

EXECUTIVE SUMMARY

The Hawaiian Electric Companies issued the final Stage 2 Request for Proposals for Variable Renewable Dispatchable Generation and Energy Storage for the Island of Maui (the "Stage 2 RFP")[1] in accordance with Commission Order No. 36474[2] in Docket 2017-0352. The Stage 2 RFP identified a Storage Requirement of up to 40 megawatts ("MW") of energy storage capacity, and also allowed the Company to submit a self-build proposal subject to the requirements of the Stage 2 RFP.

The Waena BESS Project was submitted in response to the Stage 2 RFP as a Company self-build proposal to provide 40 MW and 160 MWh of grid-tied standalone storage.[3] As discussed further in Section VII below, the Project will provide the necessary capacity needed in order to enable the retirement of Kahului Power Plant, and allow the integration of more renewable resources on the Maui grid which will be needed to meet the 100% renewable resources goal by 2045.

As outlined in the final RFP, a robust three phase bid evaluation process, approved by the Commission and overseen by the Independent Observer, evaluated the projects submitted for consideration in response to the Stage 2 RFP. The Stage 2 RFP proposals submitted for standalone energy storage and generation projects paired with storage intending to meet the energy MWh target and the Storage Requirement target were evaluated together as Portfolios. Projects selected for each Portfolio were based on the evaluation of the Net Cost (Cost and Benefits) of integrating the Portfolio into the Company's system and as compared against the base case as described in the RFP. The evaluation and ultimate ranking and selection of projects

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[1] See Docket 2017-0352, *Request for Proposals for Variable Renewable Dispatchable Generation and Energy Storage Island of Maui*, Book 3 of 7, filed August 22, 2019.
[2] See Docket 2017-0352, Order No. 36474, filed August 15, 2019.
[3] See Docket 2017-0352, *Maui Electric Company, Inc Stage 2 Self-Build Proposal*, filed November 4, 2019.

was overseen by the Independent Observer selected by the Commission. The Waena BESS Project was selected to the Final Award Group through this process.

According to the principles of the Framework for Competitive Bidding, and throughout the development and execution of the Stage 2 RFP, the Commission and the Company strove to ensure that the Company's self-build proposals were developed and evaluated fairly and consistently against proposals submitted by independent power producers ("IPPs"). This Application continues that intent, seeking approvals from the Commission that are consistent with the way that IPPs are treated and compensated. Specifically, the Company proposes herein that:

- The Project is approved in an expedited manner consistent with IPP Power Purchase Agreement applications, and primarily based on its selection to the Final Award Group in the Stage 2 RFP, which was approved by the Commission and executed under the supervision of the Independent Observer,
- The Project and the Company conform to the applicable requirements of the Energy Storage Power Purchase Agreement ("ESPPA"), including performance requirements, schedule requirements and adjustments, and penalties associated with non-compliance,
- Recovery of capital and operations and maintenance ("O&M") costs are capped at the amounts proposed in the winning self-build bid,
- The accounting treatments and assumptions used to develop the revenue requirements upon which the self-build bid was selected are approved, and
- A Shared Savings Mechanism ("SSM") is implemented whereby 10% of any cost

savings are passed to customers.[4]

The proposed Waena BESS Project consists of Maui Electric's construction of a 40 MW/160 megawatt-hour ("MWh") BESS at Maui Electric's Company-owned Waena Site in Central Maui, and the operation of the BESS for a 20-year period. As required by the Stage 2 RFP, the facility will meet the technical and operational requirements detailed in the RFP and the applicable terms of the associated ESPPA as detailed in this Application. The Company's Waena site was offered to all bidders in the Stage 2 RFP as a BESS site, and is an excellent location for a number of reasons, including: (1) no additional land costs; (2) minimal site preparation; (3) proximity to the point of interconnection at the Waena Switchyard; and (4) minimal permitting requirements in an industrial area. By using the Waena site and working closely with selected partners, the Company developed a proposal that was selected to the Final Award Group in the Stage 2 RFP to meet the Storage Requirement of the RFP at the best value to customers.

The Waena Switchyard will be proposed as a separate project, as it was developed independently of the Stage 2 RFP. Construction efforts for the Waena BESS Project will be coordinated with the schedule for the Waena Switchyard.

The Waena BESS Project is scheduled to commence construction in March 2022 with an in-service date of April 2023, at a total estimated cost of $60.0 million. The largest component of the Project cost is the contract that will cover the engineering, procurement, and construction ("EPC contract") of the Project's BESS. The interconnection of the BESS to the Waena Switchyard will be in addition to the aforementioned BESS EPC contract cost. Maui Electric staff, Hawaiian Electric personnel, and outside consultants will perform development, project

[4] See Docket 2018-0088, *Companies' Correction to their Second Updated Comprehensive Proposal*, filed May 14, 2020.

management, and engineering work on the Project.

The Commission's Major Project Interim Recovery ("MPIR") Guidelines ("MPIR Guidelines")[5] specifically identify energy storage projects as Grid Modernization Projects that are eligible for recovery through the MPIR adjustment mechanism. Accordingly, Maui Electric proposes that the costs of the Waena BESS Project be recovered through the MPIR adjustment mechanism until base rates that reflect the revenue requirements associated with the Project costs take effect in a future Maui Electric rate case.

Maui Electric respectfully submits that the proposed project is reasonable and in the public interest, and should be approved, as:

- The Project was selected through a Commission-approved competitive procurement process that has resulted in the lowest cost to customers for a required resource;
- The Project incorporates the cost, performance, and financial obligations required of a self-build project as required by the Stage 2 RFP, consistent with applicable Energy Storage Power Purchase Agreement requirements, as set forth in the Self Build Option Team Certification (See Exhibit 1); [6]
- The parameters of the Project are consistent with the Power Supply Improvement Plan ("PSIP") Update Report and the Commission's Inclinations;"[7]

[5] The Commission's *MPIR Guidelines* ("MPIR Guidelines") are set forth in Attachment A to Order No. 34514 *Establishing Performance Incentive Measures and Addressing Outstanding Schedule B Issues* ("Order 34514"), filed April 27, 2017 in Docket No. 2013-0141.

[6] See Docket No. 2014-0183, Decision and Order ("D&O") 34696 at 3: "The commission expects the Companies to continuously improve and refine their resource planning tools and methods, and employ these tools to support appropriate competitive procurement processes and Project applications in the near term."

[7] The Commission's Inclinations on the Future of Hawaii's Electric Utilities ("Commission's Inclinations") were appended as Exhibit A to D&O No. 32052, filed April 28, 2014 in Docket No. 2012-0036.

- The Project contributes to the State's goal of greater energy security and energy self-sufficiency.

I.

REQUESTED APPROVALS

Maui Electric respectfully requests that the Commission issue a D&O:

1. Approving implementation of the Waena BESS Project at a total current estimated cost of $60.0 million as further described in Exhibit 2;
2. Approving a commitment of funds in excess of $2,500,000 for the Project, net of customer contributions, as further described below, pursuant to Paragraph 2.3(g)(2) of the Commission's General Order No. 7, as modified by D&O No. 21002, filed May 27, 2004 in Docket No. 03-0257 ("G.O. 7");
3. Approving the proposed accounting and ratemaking treatment for the Project, as further described in Section VIII below, including:
   a. As further described in Exhibit 3, recovery of the Project costs through the MPIR adjustment mechanism established in Order 34514, filed April 27, 2017 in Docket No. 2013-0141, until base rates that reflect the revenue requirements associated with the Project costs take effect in a future rate case or general rate setting proceeding; and
   b. Acknowledge notification of the new asset category for accounting purposes, FERC plant account 348 Energy Storage Equipment – Production and the Company's intent to include the battery related cost in this account; and
   c. Depreciation of the battery related cost over 20 years (5% annually); and

d. Rate of return as approved in the Company's most recent rate case; and

e. An SSM under which the Company would recover 90% of any cost savings under the approved cost cap.

4. Determining that a public hearing is not required, pursuant to Section 269-27.5 of the Hawai'i Revised Statutes ("HRS")

5. Approving the construction of the 69kV sub-transmission line for the Project above the surface of the ground, as discussed in Section IX below, pursuant to Section 269-27.6(a) of the HRS.

6. Granting Maui Electric such other and further relief as may be just and equitable in the premises.

II.

MAUI ELECTRIC COMPANY, LTD.

Maui Electric, whose principal place of business and whose executive offices are located at 210 West Kamehameha Avenue, Kahului, Hawai'i, is a corporation duly organized under the laws of the Republic of Hawai'i on or about April 1, 1921, and now exists under and by virtue of the laws of the State of Hawai'i. Maui Electric is an operating public utility engaged in the production, purchase, transmission, distribution and sale of electricity on the island of Maui.

III.

CORRESPONDENCE

Correspondence and communications regarding this Application should be addressed to:

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Director – Regulatory Non-Rate Proceedings
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P.O. Box 2750
Honolulu, Hawai'i 96840-0001

Kevin.Katsura@hawaiianelectric.com
Regulatory@hawaiianelectric.com

IV.

EXHIBITS

The following Exhibits are provided in support of this Application:

Exhibit 1 – Waena BESS Project Applicable Energy Storage Power Purchase Agreement Provisions

Exhibit 2 – Waena Project Cost Summary, Vendor Pricing and Project Risk

Exhibit 3 – Waena BESS Project MPIR Model (Illustrative Maui Electric Decoupling Calculation Workbook)

Exhibit 4 – Waena Site Plan View

Exhibit 5 – Net Revenue Requirement and Bill Impact

Exhibit 6 – Project Justification Business Case Support for Waena BESS Project

Exhibit 7 – Community Outreach Plan

Exhibit 8 – Public Comments, Questions and Responses

Exhibit 9 – Confidentiality Log

Portions of the Exhibits have been redacted as confidential and unredacted versions of the same will be filed upon the issuance of an appropriate protective order in this Docket. As set forth in Exhibit 9, the redacted information contains confidential information in the form of negotiating positions, proposals, strategies, financial and pricing information, which if publicly disclosed, could disadvantage and competitively harm the Companies in future responses to RFPs.

Maui Electric acknowledges that certain types of information identified as confidential in the Exhibits, including the Company's costs, have been disclosed as public information in other documents or proceedings. In this instance, however, the specificity of that information, whether or not it reflects modification from information previously disclosed, and how it has been applied in developing the Company's response to the Stage 2 RFP should be considered and treated as confidential.

The public disclosure of what is included in the Company's bid would provide a recipe, enabling competitors to not provide their best price in response to subsequent RFP's, but rather a price at or slightly below what is offered by Maui Electric. The Company contends that disclosure of the information will not only harm the Company competitively, but would also have an adverse impact on subsequent RFPs.

V.

STATUTORY PROVISION OR AUTHORITY

The approvals in this Application are requested pursuant to Sections 226-18, 269-6, 269-6(b), 269-7, 269-16, 269-27.5, 269-27.6, 269-91 and 269-92 of the HRS; Section 16-601-74 of the *Rules of Practice and Procedure Before the Public Utilities Commission*, Title 16, Chapter 601 of the Hawaiʻi Administrative Rules ("HAR"); G.O. 7 Paragraph 2.3(g)(2), as modified by D&O 21002 filed May 27, 2004 in Docket No. 03-0257, Order No. 36474 *Approving the Hawaiian Electric Companies' Phase 2 Draft Requests for Proposals, with Modifications*, issued August 15, 2019 in Docket No. 2017-0352; Decision and Order No. 34696, filed July 14, 2017 in Docket No. 2014-0183 (PSIP docket); the Commission's *MPIR Guidelines* ("MPIR Guidelines") as set forth in Attachment A to Order No. 34514 *Establishing Performance Incentive Measures and Addressing Outstanding Schedule B Issues* ("Order 34514"), filed April 27, 2017 in Docket No. 2013-0141; and D&O No. 35606 in Docket No. 2016-0431 issued on July 30, 2018 in the Hawaiian Electric Companies' most recent depreciation rates proceeding.

VI.

ROLE OF ENERGY STORAGE

In the PSIP Update Report the Hawaiian Electric Companies discussed how energy storage technologies are increasing the flexibility to utilize renewable technologies in electric grids and revolutionizing the way customers manage their energy costs.[8] The Companies' grid modernization stakeholder outreach efforts have revealed that:

> Storage (particularly battery storage, at present) is seen by all stakeholder groups as the 'Holy Grail' of Hawai'i's energy future, to quote one of the energy experts. It must be noted, however, that some residential customers believe that energy can be stored in the grid currently and used when needed. Customers across all stakeholder groups want to see larger-scale, grid-connected storage located around each of the islands to help stabilize the grid and increase efficiency . . . .[9]

The Commission's Inclinations[10] specifically identify the need to aggressively seek lower-cost, new utility-scale renewable resources as a step toward creating a 21st century generation system, and further states that Hawaiian Electric should modernize the generation system to achieve a future with high penetrations of renewable resources, in which the Company should utilize new tools such as energy storage in order to promote grid flexibility efficiently, and cost-effectively. In Act 97 of the 2015 Hawai'i Session Laws, the Legislature increased the Renewable Portfolio Standard ("RPS") goals for the State's electric utilities, including an unprecedented 100% RPS goal by 2045. As the Companies increase the amount of variable energy production they install and contract for, energy storage will play a growing role in distributing that energy throughout the day to coincide with demand, and to provide grid services such as fast frequency response ("FFR"), contingency reserves, and load-shifting.

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[8] *PSIP Update Report: December 2016* at I-3.
[9] Docket No. 2017-0226, *Modernizing Hawai'i's Grid For Our Customers*, filed August 29, 2017 at 9
[10] Docket No. 2012-0036, D&O No. 32052, Exhibit A, filed April 28, 2014.

In support of these policies, the Company solicited Energy Storage resources for the island of Maui, which could be fulfilled by standalone energy storage projects. The proposed Waena BESS Project which is a 40MW/160MWh battery system targeted for service in 2023, will serve as a capacity resource on the Maui grid, which will enable the retirement of the Kahului Power Plant. In addition to its capacity role, and as required by the Stage 2 RFP, it will have the capability to serve as an energy-shifting resource, as well as providing grid-following, grid-forming and blackstart capabilities.

VII.

PROJECT INFORMATION

A. PROJECT DESCRIPTION

1. Project Scope

The Waena BESS Project proposes to install, own and operate a 40 MW/160 MWh BESS on Company-owned property in central Maui for a 20 year term. The energy storage system will be grid-tied via the Waena Switchyard. The proposed energy storage system is intended to satisfy the requirements for a "standalone energy storage" project, as defined in the Stage 2 RFP and the requirements noted in the associated ESPPA.

The BESS will consist of 51 pad-mounted Tesla Megapacks, 12 pad-mounted medium voltage transformers, a Tesla site controller system, medium voltage switchgear, and two step-up transformers ("GSU"). The Company selected Tesla's Megapack lithium ion battery system for the Project based on market pricing and the ability of this technology to meet all technical requirements of the Project.

Each Megapack is a modular outdoor rated cabinet, housing battery racks, inverters, and an integrated cooling system. Several Megapacks are then tied to each of the medium voltage transformers that step the voltage up from 480 V to 34.5 kV. The 51 Megapack configuration will provide 40 MW/160 MWh power and energy capacities. In order to sustain these rated capacities through the rated number of battery cycles for the 20-year Project life, periodic augmentations of the initial Megapack configuration will be required.

The combined output from the medium voltage transformers will run through a medium voltage switchgear before the voltage is stepped up again by the two GSUs to 69 kV. The output from the GSUs will tie into the Waena Switchyard via two new 300 foot long 69kV overhead lines. The new overhead lines will remain entirely on the Company's Waena property, and run from a new approximately 15 foot tall deadend structure at the Waena BESS to the approximately 15 foot tall overhead bus of a new 69 kV bay in the Waena Switchyard. The cost of this interconnection, including the new bay in the Waena Switchyard, is included in the cost of this Waena BESS Project.

The BESS also includes a system controller and battery management system ("BMS"), which controls the entire battery system and integrates the charging and discharging of the BESS with Maui Electric's energy management system ("EMS"). The site controller and BMS will be integrated into the Company's telecommunications network and receive the dispatch commands from the EMS. The BMS will control individual inverters and the charging/discharging of the battery racks to provide the required services while optimizing BESS performance and providing monitoring, protection, and balancing of the battery modules.

2. <u>Use Case and Battery Performance</u>

The facility will provide the 40 MW and 160 MWh of power and energy capacity sought by the Stage 2 RFP. Although the primary function of the Project is intended to be for capacity as outlined in the RFP, it will also have the installed capability to conduct daily energy shifting, and provide grid following, grid forming, and black-start capabilities as the RFP required.

The proposed Project has a lifecycle of 20 years, throughout which the Company will maintain the performance and capacity of the BESS to the parameters required in the Stage 2 RFP. This will be accomplished by three complementary efforts: initial design capacity, a comprehensive system maintenance plan, and a manufacturer warranty.

The Project will be designed and installed to meet the capacity requirements specified in the RFP from the start. As the battery system capacity degrades over time, augmentation with additional battery units will be required in order to sustain the facility's power and energy capacity at the rated levels. The Project will be designed to accommodate this expected augmentation.

The planned maintenance of the BESS, and the sustainment of the rated capacity over the 20-year life of the BESS, will be accomplished under a comprehensive maintenance contract with Tesla. This contract will include routine maintenance of Tesla components, as well as replacement of degraded components and the installation of new augmentation battery units as required. Routine maintenance of supporting equipment such as transformers and switchgear will be performed by Company personnel.

3. <u>Project Location</u>

The Project will be built on 1.8 acres of Maui Electric's Waena property shown in Exhibit 4, located in Central Maui. The area reserved for the Waena BESS Project is part of a larger Company-owned parcel and is currently zoned M-2 Heavy Industrial District.

4. <u>Project Staffing</u>

No additional staffing is planned to operate and maintain the Waena BESS. Company personnel will perform routine maintenance on the BESS and the supporting equipment such as transformers. A maintenance contract with Tesla for the duration of the Project will ensure that the system is maintained and can meet the performance requirements specified in the Stage 2 RFP for the life of the Project.

5. Applicable ESPPA Provisions

The model ESPPA was drafted and intended to govern the relationship between Company, as utility operator and purchaser of Energy Storage Services, and a third-party "Seller," as owner and operator of a battery energy storage system and seller of the availability of the Energy Storage Services. Because the self-build option ("SBO") does not fit within this contract paradigm, and the ESPPA was not specifically drafted to address a SBO, Section 1.9 of the Stage 2 RFP,[11] which sets forth the procedures for self-build proposals, recognized that the SBO would not be required to enter into the model ESPPA; rather, the SBO would be asked to commit to comply with specific ESPPA provisions set forth in Appendix G Attachment 1, Self-Build Option Team Certification Form:

> * * * *
>
> . . . Except where specifically noted, an SBO Proposal must adhere to the same price and non-price Proposal requirements as required of all Proposers, as well as certain PPA requirements, such as milestones and liquidated damages, as described in Appendix G. The non-negotiability of the Performance Standards shall apply to any SBO to the same extent it would for any other Proposal. Notwithstanding the fact that it will not be required to enter into an RDG PPA or ESPPA with the Company, a Self-Build Proposer will be required to note its exceptions, if any, to the RDG PPA and/or ESPPA in the same manner required of other Proposers, and will be held to such modified parameters if selected. In addition to its Proposal, the Self-Build Team will be required to submit Appendix G Attachment 1, Self-Build Option Team Certification Form, acknowledging . . . adherence to PPA terms and milestones required of all proposers and the SBO's proposed cost protection measures.

[11] See Docket 2017-0352, *Request for Proposals for Variable Renewable Dispatchable Generation and Energy Storage Island of Maui*, Book 3 of 7, filed August 22, 2019.

> The cost recovery methods between a regulated utility SBO Proposal and IPP Proposals are fundamentally different due to the business environments they operate in. As a result, the Company has instituted a process to compare the two types of proposals for the initial evaluation of the price related criteria on a 'like' basis through comparative analysis. (Emphasis in original).
>
> * * * *

Section 3.8.4 of the Stage 2 RFP similarly notes that the SBO will not execute the model ESPPA but would be held to the provisions stated in the Self Build Option Certification, subject to any proposed SBO modifications, and as adjusted with the approval of the Commission:

> If selected, a Self-Build Proposer will not be required to enter into a PPA or ESPPA with the Company. However, the Self-Build Proposer will be held to the proposed modifications to the RDG PPA and/or ESPPA, if any, it submits as part of the SBO in accordance with <u>Section 3.8.7</u>. Moreover, the SBO will be held to the same performance metrics and milestones set forth in the RDG PPA and/or ESPPA to the same extent as all Proposers, as attested to in the SBO's <u>Appendix G, Attachment 1, Self Build Option Certification</u> submittal. If liquidated damages are assessed, they will be paid from shareholder funds and returned to customers through the Purchased Power Adjustment Clause ("PPAC") or other appropriate rate adjustment mechanisms.
>
> To retain the benefits of operational flexibility for a Company-owned facility, the SBO will be permitted to adjust operational requirements and performance metrics with the approval of the PUC. The process for adjustment would be similar to a negotiated amendment to a PPA with PUC approval. (Emphasis in original).

Further recognizing that the SBO does not fit squarely within the model ESPPA contract paradigm, the Self-Build Option Team Certification specifically acknowledged that ESPPA terms related to commercial and legal interactions between "Seller" and the Company were not applicable:

> The SBO Proposal will be consistent with the scope of work and responsibilities of the "Seller" under the terms of the applicable Model PPA

excluding inapplicable terms related to commercial and legal interactions between the Seller and the Company.[12]

The Self Build Option Team Certification further served to identify the particular ESPPA provisions that would apply to the Proposal. Specifically, pursuant to the Self Build Option Team Certification, the Self Build Team agreed that the SBO Facility will be designed and constructed to:

a. Achieve the Performance Standards identified in Section 3 - Performance Standards, in Attachment B of the applicable Model [ESPPA] as modified by the IRS (subject to reasonable adjustment agreeable to the Company consistent with the Company's negotiation of such performance standards that would be completed with an independent power producer under similar circumstances);[13]

b. Meet the performance metrics as specified in . . . Article 4 of the ESPPA . . . [f]or Storage facilities (paired storage or standalone storage), (i) Storage Annual Equipment Availability Factor, (ii) Storage Annual Equivalent Forced Outage Factor, and (iii) Storage Capacity Ratio;[14]

c. Pass the Acceptance Test specified in Attachment N - Acceptance Test General Criteria of the applicable Model . . . ESPPA;[15]

d. Pass the Control System Performance Test specified in Attachment O – Control System Acceptance Test Criteria of the applicable Model . . . ESPPA;[16]

e. If applicable, pass the On-line Performance Test specified in . . . Attachment T - Facility Tests of the Model ESPPA;[17] and

f. Meet the project milestones identified in the SBO Proposal no later than the dates specified therein, which shall be consistent with the guaranteed project milestones required in Attachment K - Guaranteed Project Milestones of the Model . . . ESPPA (subject to reasonable adjustment agreeable to the Company consistent with the Company's negotiation of such milestones that would be completed with an independent power producer under similar circumstances). Notice of completion of milestones and any delay will be provided to PUC and Consumer Advocate.[18]

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[12] Self Build Option Team Certification, Section D.1. (emphasis added).
[13] Self Build Option Team Certification, Section D.2.a.
[14] *Id.* at Section D.2.b.b.3.
[15] *Id.* at Section D.2.c.
[16] *Id.* at Section D.2.d.s
[17] *Id.* at Section D.2.e.
[18] *Id.* at Section D.2.g.

In addition, under the Self Build Option Team Certification, the Self Build Team further agreed that the Company:

> a. [Will] achieve the reporting milestones identified in the SBO Proposal no later than the dates specified therein, which shall be consistent with the reporting milestones required in Attachment L - Reporting Milestones of the Model . . . ESPPA (subject to reasonable adjustment agreeable to the Company consistent with the Company's negotiation of such milestones that would be completed with an independent power producer under similar circumstances). Notice of completion of milestones and any delay will be provided to PUC and Consumer Advocate;[19]
>
> b. Will be subject to the applicable liquidated damages for the . . . ESPPA provisions above. These liquidated damages would be paid from shareholder funds and would be passed through to customers through the Companies' Power Purchase Adjustment Clause. Notice of any liquidated damages assessed and amounts of such liquidated damages will be provided to PUC and Consumer Advocate;[20] and
>
> c. Will provide annual report to PUC and Consumer Advocate on performance metrics.[21]

Finally, the Self Build Option Team Certification contemplated that the applicable ESPPA terms would be reaffirmed in the GO7 application for any selected SBO project and the associated approval order, as is being done in this Application.[22]

Thus, consistent with the above, the Self Build Team in its Proposal agreed to: (1) meet or achieve specific ESPPA performance standards, metrics, tests, and project milestones, (2) be subject to applicable liquidated damages, (3) provide notice of any liquidated damages assessed and amounts of such liquidated damages to the Commission and Consumer Advocate, (4) provide notice of completion of project and reporting milestones and any delay to the

[19] *Id.*, Section D.2.h.
[20] *Id.*, Section D.2.i.
[21] *Id.*, Section D.2.k.
[22] *Id.*, Section D.2.j.

Commission and Consumer Advocate, and (5) provide an annual report to the Commission and Consumer Advocate on performance metrics.[23]

In addition, and as required by the Stage 2 RFP, the Self Build Team noted certain inapplicable ESPPA terms and exceptions in Attachment 2.4.1 to its Proposal. In particular, Attachment 2.4.1. identified ESPPA provisions that were inapplicable because the SBO and the Company were the "same legal entity" and because the provisions were not applicable to the SBO (e.g., because the provisions applied to solar projects).[24] The Company acknowledges that the list of inapplicable terms and exceptions set forth in Attachment 2.4.1. is not exhaustive as it does not include a number of provisions that are not applicable to the Project, as reflected in Exhibit 1; however, the Company does not believe that this oversight should have a material impact on this Application, especially where the Stage 2 RFP makes clear that the SBO will not be required to enter into the ESPPA and where the Self Build Option Team Certification acknowledged and agreed that terms of the ESPPA related to commercial and legal interactions between the Seller and the Company are inapplicable and excluded.[25]

Therefore, Exhibit 1, attached hereto, reflects for convenience, a consolidation of applicable provisions of the ESPPA related to performance standards, metrics, tests, project milestones, and liquidated damages that the Company has agreed will govern the Project, as set forth in and subject to the Self Build Option Team Certification. As discussed above, because the SBO does not fit the model ESPPA contract paradigm, the ESPPA language itself in turn does not always align with an SBO project. As such, in addition to excluding inapplicable terms, in some areas the Company has edited ESPPA provisions for application to a SBO while

[23] *See* Self Build Option Team Certification.
[24] Attachment 2.4.1 also referenced provisions the SBO expected would be incorporated into the GO7 application process.
[25] Self Build Option Team Certification, Section D.1.

attempting to retain the original intent of the provision; in other areas, for clarity, the Company will note how the Company intends the provisions would be implemented for a SBO – for example, for all sections in Exhibit 1 providing for an interaction between "Seller" and "Company," such interaction shall be incorporated into the Company's internal project management, operations, and/or oversight processes. In addition, similar to an IPP, the Company may adjust interim milestone dates based on the results of the Interconnection Requirements Study which is ongoing.

B. PROJECT COST

1. Capital Cost

The total capital cost for the Waena BESS Project which was bid into the Stage 2 RFP is $60.0 million. As required by the Stage 2 RFP and to be consistent with how an IPP would be compensated, the Company proposes to cap the recovery of the Project's capital cost at the $60.0 million bid amount. The Company also proposes an SSM whereby 90% of any capital cost savings, as measured by the difference between the proposed $60.0 million and the actual project capital cost, be included in the Company's allowed cost recovery, as described in the accounting treatment below. This capital cost SSM is more beneficial to customers than an IPP would allow under the ESPPA.

The largest component of the cost estimate is for the EPC contract, which will include:

a. Engineering of the BESS (including hardware, and software programming of the battery management and control systems);

b. Procurement of BESS equipment including Megapacks, wiring, medium voltage transformers, medium voltage switchgear and control systems;

c. Site Development and construction;

d. System commissioning and integration; and

e. Permitting

See Exhibit 2 of this Application for cost details.

The remaining Project scope of work outside of the EPC contractor's responsibility may be conducted by Maui Electric personnel or be contracted out, and includes the following:

a. Engineering, procurement, and installation of the high voltage interconnection and metering equipment, including the new 69 kV bay and breakers at the Waena Switchyard, and the overhead connection;

b. Labor and materials to integrate the BESS with Maui Electric's EMS; and

c. Project management of the Maui Electric work and management of the EPC contract.

2. <u>O&M Costs.</u>

In addition to Project capital costs, O&M costs were also provided in the Company's self-build proposal into the Stage 2 RFP. These forecast O&M costs include Company labor for the proposed Project, as well as the Tesla maintenance support contract, and other costs associated with the 20 year operation of the Project. Details of the forecast O&M costs are provided in Exhibit 5.

As indicated in the Stage 2 RFP, the Company proposes to cap the recovery of O&M costs at the amounts provided in the Company's self-build proposal. The Company also proposes an SSM whereby 90% of any O&M cost savings, as measured by the difference between the proposed annual amounts shown in Exhibit 5 and the actual project annual O&M costs, be included in the Company's allowed cost recovery, as described in the accounting treatment below. This SSM is more beneficial to customers than an IPP would allow under the

ESPPA.

C. PROJECT JUSTIFICATION

Maui Electric respectfully submits that the proposed Project is reasonable and in the public interest, and should be approved for the following reasons:

1. The Project was selected to the Final Award Group in the Stage 2 RFP, the requirements and procedures for which were approved by the Commission and overseen by the Independent Observer.

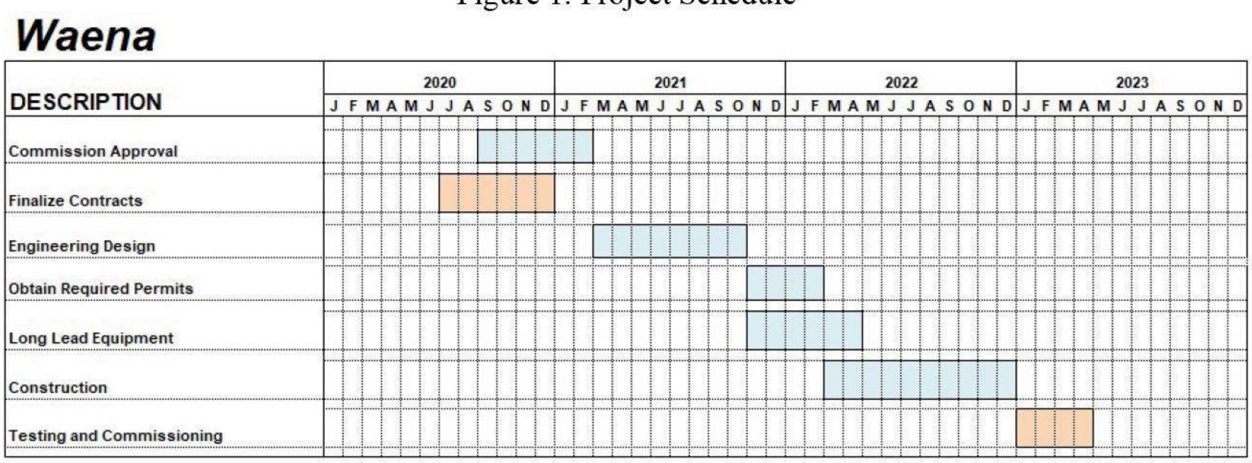
2. The Stage 2 RFP, as approved, was consistent with the PSIP Update Report and the Commission's Inclinations and contributed to the State's goal of greater energy security and energy self-sufficiency.

3. The Project will provide capacity that is required to enable the retirement of Kahului Power Plant.

D. PROJECT SCHEDULE

The Waena BESS Project is proposed to be placed in service in April 2023, as required by the Stage 2 RFP. Installation and construction of the Project is anticipated to commence in March 2022. A high-level Project schedule showing major tasks is provided in Figure 1, below.

Figure 1: Project Schedule



The “critical path” schedule for the Project (i.e., the sequence of events that cannot be delayed without delaying completion of the entire Project) is expected to include the following items:

1. The receipt of a final D&O approving this Application by the Commission within 6 months from the Application filing date;
2. Engineering, procurement and delivery of the BESS is estimated to take 18 months from the Notice to Proceed[26];
3. Installation of the BESS and final tie-in to the Waena Switchyard is estimated to take approximately 10 months; and
4. Testing and commissioning of the battery system is estimated to take up to 4 months.

To the extent that the time to complete any of the critical path items above can be reduced, the proposed BESS can be placed in service earlier than scheduled and used on the system. Correspondingly, additional time needed to complete any of the above steps will result in a later in-service date.

Other required project approvals and tasks, while necessary to complete the Project, have some flexibility as to when they need to be completed while still meeting the anticipated Project in-service date. However, they could become critical path items if significantly delayed or if their schedules are affected by compression of other critical path items.

[26] “Notice to Proceed” is a notification from the Company to a contractor stating the date the contractor can begin the work subject to the conditions of the contract.

VIII.

ACCOUNTING AND RATEMAKING TREATMENT

A. MPIR RECOVERY

Maui Electric Company is requesting to recover the costs of the Project through the MPIR adjustment mechanism until base rates that reflect the revenue requirements associated with those costs take effect in the next rate case or general rate setting proceeding.

The purpose of the MPIR adjustment mechanism is to provide a mechanism for recovery of revenues for net costs of approved Eligible Projects placed in service between general rate cases, that is not provided for by other effective tariffs. Pursuant to Section III.B.1 of the MPIR Guidelines:

> Projects and costs that may be eligible for recovery through the MPIR adjustment mechanism are Major Projects subject to review and approval in accordance with the provisions of General Order No 7, including but not restricted to the following illustrative examples, subject to the Commission's approval in accordance with these Guidelines:
>
> (a) Infrastructure that is necessary to connect renewable energy Projects. Infrastructure Projects such as transmission lines, interconnection equipment and switchyards, which are necessary to bring renewable energy to the system. For example, renewable energy Projects, such as wind farms, solar farms, biomass plants and hydroelectric plants, not located in proximity to the electric grid must overcome the additional economic barrier of constructing transmission lines, a switching station and other interconnection equipment. Building infrastructure to these Projects will encourage additional renewable generation on the grid;
>
> (b) Projects that make it possible to accept more renewable energy. Projects that can assist in the integration of more renewable energy onto the electrical grid. For example, new firm generation or modifications to firm generation to accept more variable renewable generation or energy storage and pumped hydroelectric storage facilities that allow a utility to accept and accommodate more as-available renewable energy;

(c) Projects that encourage clean energy choices and/or customer control to shift or conserve their energy use. Projects that can encourage renewable choices, facilitate conservation and efficient energy use, and/or otherwise allow customers to control their own energy use. For example, smart meters would allow customers to monitor their own consumption and use of electricity and allow for future time-based pricing programs. Systems such as automated appliance switching would provide an incentive to customers to allow a utility to mitigate sudden declines in power production inherent in as-available energy;

(d) Approved or Accepted Plans, Initiatives, and Programs. Capital investment Projects and programs, including those transformational Projects identified within the Companies' ongoing planning and investigative dockets, as such plans may be approved, modified, or accepted by the Commission, and Projects consistent with objectives established in investigative dockets;

(e) Utility Scale Generation. Electric utilities may seek recovery of the costs through the MPIR adjustment mechanism for utility scale generation that is renewable generation or a generation Project that can assist in the integration of more renewable energy onto the electrical grid;

(f) Grid Modernization Projects. Projects such as smart meters, inverters, energy storage, and distribution automation to enable demand response.

Section III.B.1.(f) of the MPIR Guidelines specifically identifies energy storage Projects under the umbrella of Grid Modernization Projects that are eligible for recovery through the MPIR adjustment mechanism. In addition, Section III.B.1(b) of the MPIR Guidelines, Projects that make it possible to accept more renewable energy, expressly recognizes energy storage as allowing a utility to accept and accommodate more as-available renewable energy and therefore eligible for recovery through the MPIR adjustment mechanism. Moreover, the Project also qualifies under Section III.B.1.(d) of the MPIR Guidelines as the proposed BESS will support the Company's PSIPs. Accordingly, the Company maintains that the proposed Project is eligible for recovery through the MPIR adjustment mechanism.

Pursuant to Section III.C.2.b of the MPIR Guidelines:

> Costs eligible for the MPIR adjustment mechanism include:
>
> (i) Return on the net of tax average annual undepreciated investment in allowed Eligible Projects during MPIR for each Project at rate of return to be determined in the review of each Eligible Project application, as approved by the commission;
>
> (ii) Recorded depreciation accruals (at a rate and methodology to be determined in review of each Project's application, and as approved by the Commission) to begin on the following January 1st after the month of the in-service date of the Project;
>
> (iii) Other relevant costs, applicable taxes, and/or offsetting cost savings, approved by the Commission.

Please refer to Exhibit 2 for a breakdown of the Project costs by these categories.

Section III.C.3.c of the MPIR Guidelines provides that: "A business case study shall be submitted with each application identifying and quantifying all operational and financial impacts of the Eligible Project and illustrating the cost/benefit tradeoffs that justify proceeding with the Project to the extent that such impacts can reasonably be determined." Section III.3.e of MPIR Guidelines similarly provides that:

> A detailed business case study shall be included, covering all aspects of the planned investments and activities, indicating all expected costs, benefits, scheduling and all reasonably anticipated operational impacts. The business case shall reasonably document and quantify the cost/benefit characteristics of the investments and activities, indicating each criterion used to evaluate and justify the Project, including consideration of expected risks and ratepayer impacts. The business case should also clearly outline how it will advance transformational efforts with appropriate quantifications, to the extent such quantifications can reasonably be determined.

The Company maintains that the business case provided as Exhibit 6 meets the criterion for business cases set forth in the MPIR Guidelines.

Section III.C.3.g of the MPIR Guidelines requires that specific criteria are proposed for the determination of used and useful status, in order to place the proposed Project into service.

In the case of the Waena BESS Project, the Company has committed to comply with the technical and performance standards detailed in the ESPPA. Included in the ESPPA provisions to which the Company has committed above are completion of the acceptance tests required of any IPP. To be consistent with the requirements placed on an IPP in order to achieve commercial operation, the Project will complete the same tests in order to be placed into service.

Accordingly, the Company is requesting initial recovery of the costs of this Project through the MPIR adjustment mechanism.

As noted above, the Waena BESS Project is proposed to be placed in service in April 2023. The Company is seeking recovery of the Project costs through the MPIR adjustment mechanism until base rates that reflect the revenue requirements associated with those costs take effect in a future rate case or the next general rate setting proceeding.

Based on an in-service date in April 2023, which is the date provided in the self-build proposal as the Guaranteed Commercial Operation Date ("GCOD") to be consistent with an IPP proposal, Exhibit 3[27] provides an illustrative example of the schedules that would be filed as part of the MPIR process, which will trigger an adjustment to target revenues by an estimated annualized amount of $3,831,000[28] starting May 1, 2023 and by an estimated annualized amount of $5,050,000[29] starting January 1, 2024 based on the February 2024 annual MPIR true-up filing.

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[27] Exhibit 3 is included to illustrate how this project will flow through the MPIR mechanism and the approximate impact on annual target revenues. This should be considered illustrative only and is subject to change. This illustration is based on the project budget and estimated date of completion as described above. The target revenue illustration as shown in Exhibit 3 includes amounts filed in Transmittal 20-03 Consolidated (Decoupling) filing which was filed on June 5, 2020. Upon completion and being placed in service, the Company will prepare and file the MPIR filing in accordance with the approved guidelines. The MPIR filing will be based on actual recorded costs and the detailed classification of the costs in the depreciation and tax calculations. Further, the target revenues will be subject to the amounts approved in the applicable decoupling filing as of the filing date.

[28] See Exhibit 3, Schedule B1. Calculated as the difference between line 34 and line 33 ($158,723,000 - $154,4892,000 = $3,831,000) and Schedule L, line 2.

[29] See Exhibit 3, Schedule B1. Calculated as the difference between line 35 and line 34 ($163,772,000 - $158,723,000 = $5,050,000) and the incremental difference between line 2 of Schedule La and Schedule L ($8,881,000 - $3,831,000 = $5,050,000).

B. <u>ACCOUNTING TREATMENT</u>

The Company is requesting special accounting treatment for the battery related cost of this Project to depreciate such cost over 20 years (5% annually) as used in the RFP and revenue requirements for the annual depreciation expense. This depreciation duration is based on the 20 year time span of the project, as detailed in the Company's self-build proposal, which is in turn based on the battery manufacturer's assessment of the optimum battery system lifespan. The 20 year depreciation schedule was used as the basis for the revenue requirements provided in the Company's self-build proposal. Since these revenue requirements served as the basis upon which the self-build proposal was selected to the Final Award Group, the Company maintains that this accounting treatment is, by extension, part of the winning bid and should be treated as such in order to be considered equivalent to an IPP.

The 20 year depreciation schedule would apply to the battery system, which for an IPP would be considered the "Facility" as defined in the Stage 2 RFP. For those interconnection assets of the Project which for an IPP project would be defined as "Company Owned" in the Stage 2 RFP, current approved depreciation rates would apply. Since the self-build proposal assumed a 20 year depreciation schedule for the entire capital cost of the project, the application of current approved depreciation rates for the interconnection portion of the project results in lower revenue requirements than those provided in the self-build proposal over the 20 year life of the Project. A comparison of the annual revenue requirements provided in Exhibit 5 (using approved depreciation for the interconnection portion of the project and a 20 year schedule for the BESS) to the revenue requirements provided in the self-build proposal (using 20 year depreciation for the full capital cost of the project) shows that the proposed treatment will result in additional cost savings to customers over the life of the project, compared to the pricing basis upon which the Company's self-build proposal was selected.

Also, the Company hereby notifies the Commission of the establishment of a new asset category for accounting purposes: Federal Energy Regulatory Commission ("FERC') plant account 348 Energy Storage Equipment – Production[30] for this battery related cost. The new asset category is consistent with FERC Uniform System of Accounts and the notification is in accordance with the Commission's D&O No. 35606 in Docket No. 2016-0431 issued on July 30, 2018 in the Hawaiian Electric Companies' most recent depreciation rates proceeding. [31] As mentioned above, the Company is requesting special accounting treatment for the battery system costs of the Project instead of utilizing the functional composite depreciation rate of a comparable asset category as approved in Order No. 35606. The depreciation rate for plant account 348 used to derive the annual depreciation expense in Exhibit 3 is the 5% annual rate as requested in this application. The current approved depreciation rates will be used for the other components of the Project.

C. <u>REVENUE REQUIREMENTS:</u>

An overview of the various revenue requirement components impacted by the Waena BESS Project is provided in Exhibit 5 of this Application. These high-level revenue requirement calculations include simplifying assumptions (e.g., Project placed in service April 2023; capital components are not parsed into specific classifications, rather are treated as one unit to which the most likely treatment applies; 20-year expected useful life). When the Company files certification of the Project completion/in-service date, detailed calculations will be provided

[30] The FERC *Uniform System of Accounts*, states that "This account shall include the cost installed of energy storage equipment used to store energy for load managing purposes."

[31] The D&O states that, "For new asset categories that arise in the future for which no depreciation rates are currently approved, the Companies shall utilize the functional composite depreciation rates of comparable asset categories approved by the commission in this proceeding. The Companies shall notify the Consumer Advocate and the commission of the new asset category, identify the composite depreciation rate to be applied, and explain the basis for selecting the rate." <u>See</u> Ordering Paragraph 2 in D&O No. 35606, Docket No. 2016-0431 at page 39.

based on actual information and the rates in place at that time, as discussed further below. An illustrative MPIR calculation for the Waena BESS Project is provided in Exhibit 3 and also discussed further below.

The following is a summary of the proposed ratemaking treatment of the various costs impacted by this Project:

Table 1: Proposed Ratemaking Treatment of Various Impacted Costs

Cost Component or Savings	Proposed Ratemaking Treatment
Waena BESS Capital	MPIR
Avoided Fuel	Energy Cost Recovery Clause ("ECRC")
Avoided Purchased Power	ECRC/Power Purchase Adjustment Clause ("PPAC")
Waena BESS O&M	MPIR
Emissions Fees	Normal Operations
Avoided Fuel Inventory	Normal Operations

The Company is requesting cost recovery of the capital and O&M components through the MPIR adjustment mechanism. The various revenue requirement components and the vehicles to address cost recovery are addressed below.

1. Capital Revenue Requirements

Capital Revenue Requirements are based on the following assumptions (see page 2 of Exhibit 5):

a. Depreciation assumptions (MPIR Guidelines Section III.C.2.ii) – The net revenue requirements assume a 20-year expected useful life of the Project. This is a high-level, simplified approach for the economic analysis. The MPIR revenue requirement will be based on the depreciation rates in place at the time of the filing for the Transmission and Switchyard costs and a 20-year (5% annual) depreciation rate for the battery related costs of the project as requested in this application.

b. Service life assumption – The revenue requirements assume a service life of 20 years.

c. Rate of return assumption (MPIR Guidelines Section III.C.2.i) – The return on rate base assumed is the composite cost of capital (7.43%) from the Maui Electric 2018 test year rate case Final D&O No. 36219 in Docket No. 2017-0150; grossed-up for income and revenue taxes (10.251%). (See page 2 of Exhibit 5.) The cost of capital will be based on the weights and rates in effect for rates at the time of the initial MPIR filing.

d. Show net of tax average annual undepreciated investment in allowed Eligible Projects (essentially a rate base calculation with capital investment, accumulated depreciation, accumulated deferred income taxes, and unamortized state investment tax credit) (MPIR Guidelines Sections III.C.2.i and III.C.3.c). (See pages 6 – 9 of Exhibit 5.) Depreciation and taxes will be based on approved rates and regulations in place at the time of the filing (when the Project goes into service and in January in the years following).

The Company proposes that the capital revenue requirements be recovered through the MPIR adjustment mechanism until the revenue requirements are recovered in base rates in a future rate case or general rate setting proceeding. Page 1 of Exhibit 5 calculates the capital revenue requirements at a high level. In the actual MPIR filing, the revenue requirements will be based on actual costs adjusted for the SSM and detailed classification of the costs in the depreciation and tax calculations. An illustration of the MPIR calculation is provided in Exhibit 3.

2. Shared Savings Mechanism

Section 1.9 of the Stage 2 RFP provided the following:

> The SBO will be permitted to submit a shared savings mechanism with its Proposal to share in any cost savings between the amount of cost bid in the SBO Proposal and the actual cost to construct the Project. If the SBO Proposal is selected to the Final Award Group, the proposed shared savings mechanism will need to be approved by the PUC. Submission of a shared savings mechanism is not required and will not be considered in the evaluation of the SBO Proposal.

To be consistent with the requirements of the RFP, the Company agrees that capital and O&M cost recovery for the Project will be capped at the amounts proposed in the self-build proposal. However, as allowed in the RFP, the Company proposes an SSM for the situation where actual costs are less than the approved capped amount, which is intended to be consistent with how an IPP would be compensated, while still providing savings to customers. If the Company completes and operates the Project with total actual costs less than the approved and capped amounts for capital and annual O&M, 90% of the savings would be retained by the Company. This method provides more savings to customers than an IPP would provide under comparable circumstances.

3. Utilization of the MPIR Adjustment Mechanism:

To recap the proposed utilization of the MPIR adjustment mechanism for the Waena BESS Project, the Company proposes the following:

a. Revenue requirements associated with the capital costs of the Project flow through the MPIR adjustment mechanism;

b. Depreciation rates applied will be the current approved depreciation rates except for the battery related cost which the Company requests special accounting treatment to depreciated over 20 years (5% annually) in this application. The battery related cost is to be included in FERC plant account 348 – Energy Storage Equipment – Production;

c. Project O&M flow through the MPIR adjustment mechanism.

d. O&M expenses that would be included in the MPIR adjustment mechanism, will be the estimated O&M expenses for the year included in the bid in the RFP, and included in Exhibit 5, page 1. This is the committed O&M expenses for the project.;

    (i) Consistent with an IPP, the actual O&M expenses would be at the risk of the company. Actual annual O&M expenses for the Project would be compared with the annual amounts included in the MPIR adjustment for the year. If actual O&M expenses are less than the amounts included in the MPIR adjustment, 90% of the difference, net of taxes, would be a downward adjustment to recorded earnings in determining the Company's earnings for purposes of the earning sharing mechanism. If actual O&M expenses are higher than the amounts included in the MPIR adjustment, the difference, net of taxes, would be an upward adjustment to recorded earnings in determining the Company's earnings for purposes of the earnings sharing mechanism.

The in-service date of Waena BESS of no later than April 2023 will trigger, as part of the MPIR process, an adjustment to target revenues by an estimated annualized amount of $3,831,000 beginning May 1, 2023, as illustrated in Exhibit 3, Schedule L. Recovery through the MPIR adjustment mechanism would cease when the revenue requirements are reflected in base rates in a future rate case or general rate setting proceeding.

4. Damages and Penalties

As required by the Stage 2 RFP, committed to in the Company's self-build proposal, and detailed in this Application, the Company proposes that the Project complies with applicable provisions of the ESPPA. Under the circumstances and to the extent that the applicable provisions of the ESPPA would require an IPP to pay damages or penalties to the Company, the Company would also pay such damages and penalties for this Project. In these cases, the Company proposes to return any damages or penalties incurred to customers through the PPAC, similarly to how IPP damages or penalties are currently returned to customers.

IX.

BILL IMPACT

The project costs will have an average $3.22 impact on the typical monthly 500 kWh residential bill over 20 years as shown in Exhibit 5[32].

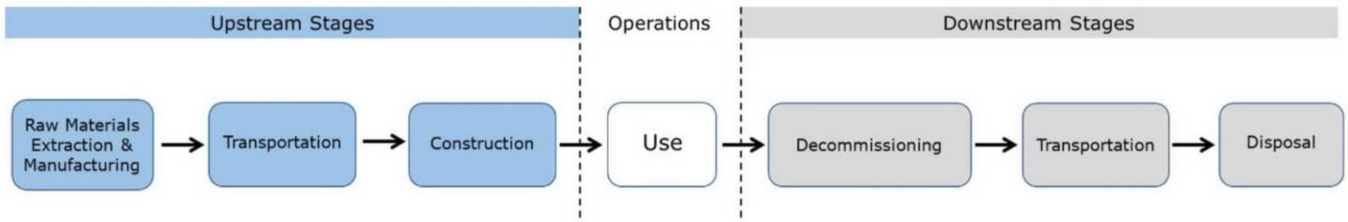
X.

GREENHOUSE GAS ANALYSIS

The methodology described below will be utilized to estimate the Greenhouse Gas ("GHG") emissions associated with the proposed Waena Battery Energy Storage System project. Maui Electric will submit the GHG analysis as described below, to the Commission by September 30th, 2020. This approach addresses the Upstream, Construction, Operations, and Downstream Stages, as shown in Figure 2, below.

[32] The projected bill impact calculation is only intended to provide an illustrative example of potential customer bill impacts. The specific assumptions and results used in the bill impact calculations are provided in the evaluation attached hereto as Exhibit 5.

Figure 2. Stages for Consideration in GHG Emissions Calculation



Potentially significant and reasonably foreseeable equipment, materials and activities are accounted for throughout the Project lifecycle. The following sections provide an overview of the methodology for the Upstream, Operations and Downstream Stages.

A. UPSTREAM STAGES

Upstream Stages include the raw materials extraction, manufacturing, transportation and construction stages of the Project, including GHG emissions that occur off-island. GHG emissions associated with raw material extraction and manufacturing are for equipment and materials installed or used during the Project. The GHG emissions for upstream stages also consider total number of pieces of equipment within the project lifetime.

The Transportation and Construction Stages' GHG emissions are calculated using an "inventory approach" where estimated direct GHG emissions from transportation and construction are calculated based on Project- and location-specific data. This includes Upstream and Downstream transportation for material and equipment from manufacturer locations which are mostly off-island to the Project Site and from the Project Site to disposal locations. The Construction Stage includes GHG emissions produced during construction of the Project, including on-road and off-road construction GHG emissions associated with site development, foundation or civil work, and installation of new equipment.

B. OPERATIONS STAGE

Operational Emissions include direct GHG emissions associated with the operation and maintenance of the Project (e.g., the "Operations Stage" shown in Figure 1 of this section). The Operations Stage includes GHG emissions generated from operation and maintenance activities of the equipment and materials in scope for the Project, including onsite energy; material and water use; mobile trips required for worker commute, and maintenance or other operational mobile trips.

C. DOWNSTREAM STAGES

The Downstream Stages include GHG emissions from transportation, distribution, decommissioning and disposal of the proposed equipment at such time the Project is decommissioned after the projected Project lifetime.

D. REPORT

As previously stated, Hawaiian Electric will submit the GHG analysis as described above, to the Commission within 10 weeks of this submittal. The estimated GHG emissions result using the methodology described above will be presented in metric tons of Carbon dioxide equivalent (CO_2e) for the Project lifetime. Detailed calculations including assumptions and inputs will be properly documented and included with the GHG analysis report.

XI.

OVERHEAD 69kV INTERCONNECTION

A. HRS § 269-27.5 - PUBLIC HEARING.

The Project includes the installation of a short 69 kV tie-in from the BESS to an adjacent 69 kV substation, all on Company property (See Exhibit 4). A public hearing pursuant to HRS § 269-27.5 is not requested for this Project because there are no existing residential homes in or near the project site. The closest residential area is approximately 3.5 miles away. The 69 kV line extensions will not be visible from the homes, due to the distance and terrain.

B. HRS § 269-27.6(a)

Pursuant to HRS § 269-27.6, whenever a public utility applies for approval to build a new 46 kV or greater transmission line, "either above or below the surface of the ground," the Commission shall determine whether the line shall be "built above or below the surface of the ground . . .." As indicated above, the scope of the Waena BESS Project includes the engineering, procurement, and installation of a 69 kV tie-in to an adjacent 69 kV switchyard. Accordingly, Maui Electric requests that the Commission approve the proposed 69 kV interconnection for the Project be constructed above the surface of the ground, as described in Section VII.A.1 above. HRS § 269-27.6(a) provides that the Commission shall consider the following factors in making its determination:

> (1) Whether a benefit exists that outweighs the costs of placing the electric transmission system underground;
>
> (2) Whether there is a government public policy requiring the electric transmission system to be placed, constructed, erected, or built underground, and the governmental agency establishing the policy commits funds for the additional costs of undergrounding;
>
> (3) Whether any governmental agency or other parties are willing to pay for the additional costs of undergrounding;
>
> (4) The recommendation of the division of consumer advocacy of the department of commerce and consumer affairs, which shall be based on an evaluation of the factors set forth under this subsection; and
>
> (5) Any other relevant factors.

Under the circumstances, the factors above support a determination that the proposed 69 kV line be constructed above the ground. With respect to HRS § 269-27.6(a)(1), the benefit of placing the 69 kV line overhead is that the Project will only have a short run from the BESS area to Waena Switchyard, thereby reducing the cost of the Project by avoiding the underground costs which are typically 3.5 times more than an overhead connection.

With respect to HRS §§ 269-27.6(a)(2) and 269-27.6(a)(3) the Company is not aware of any governmental public policy requiring the undergrounding of the 69 kV line tap, or agency, or other parties willing to pay for the costs of the 69 kV line tap, or any other factors relevant to the Commission's determination.

In regards to HRS § 269-27.6(a)(4), the Consumer Advocate will have an opportunity to state its position upon completion of its investigation.

Regarding HRS § 269-27.6(a)(5), the Company is not aware of any other relevant factors.

C. NON-TRANSMISSION ALTERNATIVES

The Commission's Inclinations include the following guidance regarding transmission planning and the future development of new transmission Projects on Maui's grids:

> **New transmission Projects must consider non-transmission alternatives** – New, replacement or upgrade high-voltage transmission Projects generally represent significant, lumpy capital investments that will be given careful scrutiny. Non-transmission alternatives (NTAs) such as local peaking or back-up generators, energy storage, demand response and smart grid resources are technically and commercially available alternatives that must be evaluated as part of any economic justification for new transmission system Projects.[33]

The Waena BESS Project is an energy storage project, which will be constructed on Company property, immediately adjacent to a new substation. The segment of 69kV interconnection that is required to interconnect the Project with Maui Electric's grid consists of a 300 foot segment of 69kV line. As such, the Project is considered an NTA and the Company submits that no further NTA analysis should be required.

[33] Commission's Inclinations at 12.

XII.

COMMUNITY OUTREACH

A. COMMUNITY OUTREACH PLAN

As required by the Stage 2 RFP, the Company self-build team developed a community outreach plan, and executed the beginning stages of it while the RFP was in progress. Although initial in-person meetings took place prior to the COVID-19 pandemic, as distancing protocols were put into place, adjustments were made. To keep our community safe but still be able to engage with them on our project and its effects on their community, virtual public meetings were held via online platforms and rebroadcast on community television. Community members were encouraged to engage with Project team members through online chat features and via email. In addition, recorded presentations were provided on the company website. Project Community Outreach plans are provided as Exhibit 7.

B. COMMUNITY COMMENTS

Multiple avenues for participation were provided for community inquiries and feedback. A Company email was made available specific to each project, which was provided on all online public meetings and broadcasts, as well as on the project website. During live TV broadcasts community members had the opportunity to send questions to project team members via this email, and the presenters answered the questions live on the air. Comments received are provided in Exhibit 8.

Upon the filing of this Application, the Company will provide public notices initiating another 30-day period during which the community will have another opportunity to provide comments.

XIII.

CONCLUSION

Wherefore, Maui Electric respectfully requests that the Commission issue a D&O:

1. Approving implementation of the Waena BESS Project at a total current estimated cost of $60.0 million as further described in Exhibit 2;
2. Approving a commitment of funds in excess of $2,500,000 for the Project, net of customer contributions, as further described above, pursuant to Paragraph 2.3(g)(2) of the Commission's General Order No. 7, as modified by D&O No. 21002, filed May 27, 2004 in Docket No. 03-0257 ("G.O. 7");
3. Approving the proposed accounting and ratemaking treatment for the Project, as further described in Section VIII, including:
   a. As further described in Exhibit 3, recovery of the Project costs through the MPIR adjustment mechanism established in Order 34514, filed April 27, 2017 in Docket No. 2013-0141, until base rates that reflect the revenue requirements associated with the Project costs take effect in a future rate case or general rate setting proceeding; and
   b. Acknowledge notification of the new asset category for accounting purposes, FERC plant account 348 Energy Storage Equipment – Production and the Company's intent to include the battery related cost in this account; and
   c. Depreciation of the battery related cost over 20 years (5% annually); and
   d. Rate of return as approved in the Company's most recent rate case; and
   e. An SSM under which the Company would recover 90% of any cost

savings under the approved cost cap.

4. Determining that a public hearing is not required, pursuant to Section 269-27.5 of the Hawai‘i Revised Statutes (“HRS”)

5. Approving the construction of the 69kV sub-transmission line for the Project above the surface of the ground, as discussed in Section IX below, pursuant to Section 269-27.6(a) of the Hawai‘i Revised Statutes (“HRS”).

6. Granting Maui Electric such other and further relief as may be just and Equitable in the premises.

DATED: Honolulu, Hawai‘i, September 8, 2020.

HAWAIIAN ELECTRIC COMPANY, INC.

By /s/ Joseph P. Viola

Joseph P. Viola
Vice President, Regulatory Affairs

Vice President
Maui Electric Company, Limited

<u>VERIFICATION</u>

STATE OF HAWAI'I	)	
	)	ss.
CITY AND COUNTY OF HONOLULU	)	

Joseph P. Viola, being first duly sworn, deposes and says: That he is the Vice President – Regulatory Affairs of Hawaiian Electric Company, Inc., and Vice President of Maui Electric Company, Limited, Applicant in the above proceeding; that he makes this verification for and on behalf of Maui Electric Company, Limited and is authorized so to do; that he has read the foregoing Application, and knows the contents thereof; and that the same are true of his own knowledge except as to matters stated on information or belief, and that as to those matters he believes them to be true.

/s/ Joseph P. Viola
Joseph P. Viola

Exhibit 1 Energy Storage Power Purchase Agreement Provisions

Introduction

The model ESPPA was drafted and intended to govern the relationship between Company, as utility operator and purchaser of Energy Storage Services, and a third-party "Seller," as owner and operator of a battery energy storage system and seller of the availability of the Energy Storage Services. Because the self-build option ("SBO") does not fit within this contract paradigm, and the ESPPA was not specifically drafted to address a SBO, Section 1.9 of the Stage 2 RFP,[1] which sets forth the procedures for self-build proposals, recognized that the SBO would not be required to enter into the model ESPPA; rather, the SBO would be asked to commit to comply with specific ESPPA provisions set forth in Appendix G Attachment 1, Self-Build Option Team Certification Form:

> . . . Except where specifically noted, an SBO Proposal must adhere to the same price and non-price Proposal requirements as required of all Proposers, as well as certain PPA requirements, such as milestones and liquidated damages, as described in Appendix G. The non-negotiability of the Performance Standards shall apply to any SBO to the same extent it would for any other Proposal. Notwithstanding the fact that it will not be required to enter into an RDG PPA or ESPPA with the Company, a Self-Build Proposer will be required to note its exceptions, if any, to the RDG PPA and/or ESPPA in the same manner required of other Proposers, and will be held to such modified parameters if selected. In addition to its Proposal, the Self-Build Team will be required to submit Appendix G Attachment 1, Self-Build Option Team Certification Form, acknowledging . . . adherence to PPA terms and milestones required of all proposers and the SBO's proposed cost protection measures.
>
> The cost recovery methods between a regulated utility SBO Proposal and IPP Proposals are fundamentally different due to the business environments they operate in. As a result, the Company has instituted a process to compare the two types of proposals for the initial evaluation of the price related

[1] See Docket 2017-0352, *Request for Proposals for Variable Renewable Dispatchable Generation and Energy Storage Island of Maui*, Book 3 of 7, filed August 22, 2019.

> criteria on a 'like' basis through comparative analysis. (Emphasis in original).

Section 3.8.4 of the Stage 2 RFP similarly notes that the SBO will not execute the model ESPPA but would be held to the provisions stated in the Self Build Option Certification, subject to any proposed SBO modifications, and as adjusted with the approval of the Commission:

> If selected, a Self-Build Proposer will not be required to enter into a PPA or ESPPA with the Company. However, the Self-Build Proposer will be held to the proposed modifications to the RDG PPA and/or ESPPA, if any, it submits as part of the SBO in accordance with Section 3.8.7. Moreover, the SBO will be held to the same performance metrics and milestones set forth in the RDG PPA and/or ESPPA to the same extent as all Proposers, as attested to in the SBO's Appendix G, Attachment 1, Self Build Option Certification submittal. If liquidated damages are assessed, they will be paid from shareholder funds and returned to customers through the Purchased Power Adjustment Clause ("PPAC") or other appropriate rate adjustment mechanisms.
>
> To retain the benefits of operational flexibility for a Company-owned facility, the SBO will be permitted to adjust operational requirements and performance metrics with the approval of the PUC. The process for adjustment would be similar to a negotiated amendment to a PPA with PUC approval. (Emphasis in original).

Further recognizing that the SBO does not fit squarely within the model ESPPA contract paradigm, the Self-Build Option Team Certification specifically acknowledged that ESPPA terms related to commercial and legal interactions between "Seller" and the Company were not applicable:

> The SBO Proposal will be consistent with the scope of work and responsibilities of the "Seller" under the terms of the applicable Model PPA excluding inapplicable terms related to commercial and legal interactions between the Seller and the Company.[2]

The Self Build Option Team Certification further served to identify the particular ESPPA provisions that would apply to the Proposal. Specifically, pursuant to the Self Build Option

[2] Self Build Option Team Certification, Section D.1. (emphasis added).

Team Certification, the Self Build Team agreed that the SBO Facility will be designed and constructed to:

- Achieve the Performance Standards identified in Section 3 - Performance Standards, in Attachment B of the applicable Model [ESPPA] as modified by the IRS (subject to reasonable adjustment agreeable to the Company consistent with the Company's negotiation of such performance standards that would be completed with an independent power producer under similar circumstances);[3]
- Meet the performance metrics as specified in . . . Article 4 of the ESPPA . . . [f]or Storage facilities (paired storage or standalone storage), (i) Storage Annual Equipment Availability Factor, (ii) Storage Annual Equivalent Forced Outage Factor, and (iii) Storage Capacity Ratio;[4]
- Pass the Acceptance Test specified in Attachment N - Acceptance Test General Criteria of the applicable Model . . . ESPPA;[5]
- Pass the Control System Performance Test specified in Attachment O – Control System Acceptance Test Criteria of the applicable Model . . . ESPPA;[6]
- If applicable, pass the On-line Performance Test specified in . . . Attachment T - Facility Tests of the Model ESPPA;[7] and
- Meet the project milestones identified in the SBO Proposal no later than the dates specified therein, which shall be consistent with the guaranteed project milestones required in Attachment K - Guaranteed Project Milestones of the Model . . .

[3] Self Build Option Team Certification, Section D.2.a.
[4] *Id.* at Section D.2.b.b.3.
[5] *Id.* at Section D.2.c.
[6] *Id.* at Section D.2.d.s
[7] *Id.* at Section D.2.e.

ESPPA (subject to reasonable adjustment agreeable to the Company consistent with the Company's negotiation of such milestones that would be completed with an independent power producer under similar circumstances). Notice of completion of milestones and any delay will be provided to PUC and Consumer Advocate.[8]

In addition, under the Self Build Option Team Certification, the Self Build Team further agreed that the Company:

- [Will] achieve the reporting milestones identified in the SBO Proposal no later than the dates specified therein, which shall be consistent with the reporting milestones required in Attachment L - Reporting Milestones of the Model . . . ESPPA (subject to reasonable adjustment agreeable to the Company consistent with the Company's negotiation of such milestones that would be completed with an independent power producer under similar circumstances). Notice of completion of milestones and any delay will be provided to PUC and Consumer Advocate;[9]
- Will be subject to the applicable liquidated damages for the . . . ESPPA provisions above. These liquidated damages would be paid from shareholder funds and would be passed through to customers through the Companies' Power Purchase Adjustment Clause. Notice of any liquidated damages assessed and amounts of such liquidated damages will be provided to PUC and Consumer Advocate;[10] and

[8] *Id.* at Section D.2.g.
[9] *Id.*, Section D.2.h.
[10] *Id.*, Section D.2.i.

- Will provide annual report to PUC and Consumer Advocate on performance metrics.[11]

Finally, the Self Build Option Team Certification contemplated that the applicable ESPPA terms would be reaffirmed in the GO7 application for any selected SBO project and the associated approval order, as is being done in this Application.[12]

Thus, consistent with the above, the Self Build Team in its Proposal agreed to: (1) meet or achieve specific ESPPA performance standards, metrics, tests, and project milestones, (2) be subject to applicable liquidated damages, (3) provide notice of any liquidated damages assessed and amounts of such liquidated damages to the Commission and Consumer Advocate, (4) provide notice of completion of project and reporting milestones and any delay to the Commission and Consumer Advocate, and (5) provide an annual report to the Commission and Consumer Advocate on performance metrics.[13]

In addition, and as required by the Stage 2 RFP, the Self Build Team noted certain inapplicable ESPPA terms and exceptions in Attachment 2.4.1 to its Proposal. In particular, Attachment 2.4.1. identified ESPPA provisions that were inapplicable because the SBO and the Company were the "same legal entity" and because the provisions were not applicable to the SBO (e.g., because the provisions applied to solar projects).[14] The Company acknowledges that the list of inapplicable terms and exceptions set forth in Attachment 2.4.1. is not exhaustive as it does not include a number of provisions that are not applicable to the Project, as reflected in Exhibit 1; however, the Company does not believe that this oversight should have a material

[11] *Id.*, Section D.2.k.
[12] *Id.*, Section D.2.j.
[13] *See* Self Build Option Team Certification.
[14] Attachment 2.4.1 also referenced provisions the SBO expected would be incorporated into the GO7 application process.

impact on this Application, especially where the Stage 2 RFP makes clear that the SBO will not be required to enter into the ESPPA and where the Self Build Option Team Certification acknowledged and agreed that terms of the ESPPA related to commercial and legal interactions between the Seller and the Company are inapplicable and excluded.[15]

Compensation to Customers

For terms discussing payment of damages or penalties, see Section VIII of the Application, which discusses how these penalties and damages will be provided to Customers from the Company. In connection with the payment of such penalties or damages and for purposes of this Exhibit 1, "Lump Sum Payment" shall be defined as the net present value of the total actual revenue requirements divided by the 240 month lifecycle of the Project. Total actual revenue requirements shall be the sum of the capital revenue requirements based on actual project costs (adjusted for the project capital cost cap and the approved shared savings mechanism) and the proposed O&M revenue requirements.

Articles and Attachments

This Exhibit 1 reflects for convenience, a consolidation of applicable provisions of the ESPPA related to performance standards, metrics, tests, project milestones, and liquidated damages that the Company has agreed will govern the Project, as set forth in and subject to the Self Build Option Team Certification. As discussed above, because the SBO does not fit the model ESPPA contract paradigm, the ESPPA language itself in turn does not always align with an SBO project. As such, in addition to excluding inapplicable terms, in some areas, the Company has edited ESPPA provisions for application to a SBO while attempting to retain the original intent of the provision; in other areas, for clarity, the Company will note how the

[15] Self Build Option Team Certification, Section D.1.

Company intends the provisions would be implemented for a SBO – for example, for all sections in Exhibit 1 providing for an interaction between "Seller" and "Company," such interaction shall be incorporated into the Company's internal project management, operations, and/or oversight processes. Further, the daily delay LD amount has been calculated and entered in Exhibit 1, while remaining technical parameters to be determined through the final design of the Project remain blank. Finally, similar to the independent power producers, Company may, with approval from the IO, adjust interim milestone dates based on the results of the Interconnection Requirements Study which is ongoing.

Article 4: COMPENSATION; PERFORMANCE METRICS[16]

4.3 Capacity Performance Metric.

(a) Capacity Test and Liquidated Damages. During commissioning, and for each Measurement Period following the Commercial Operations Date, the Facility shall be required to complete a Capacity Test, as more fully set forth in **Attachment T** (Facility Tests) to this Agreement. For each Measurement Period for which the Facility fails to demonstrate that it satisfies the Capacity Performance Metric, Seller shall pay, and Company shall accept, as liquidated damages for such shortfall, the amount set forth in the following table (on a progressive basis) upon proper demand at the end the Measurement Period in question:

Capacity Ratio	Liquidated Damage Amount
Tier 1 95.0% - 99.9%	For each one-tenth of one percent (0.001) that the Capacity Ratio is below 100% and is above 94.9%, an amount equal to one-tenth of one percent (0.001) of the Lump Sum Payment for the Measurement Period in question; plus

[16] Unless defined herein, capitalized terms shall have the meaning stated in the model ESPPA.

Tier 2 85.0% - 94.9%	For each one-tenth of one percent (0.001) that the Capacity Ratio is below 95% and is above 84.9%, an amount equal to one and a half-tenths of one percent (0.0015) of the Lump Sum Payment for the Measurement Period in question; plus
Tier 3 75.0% - 84.9%	For each one-tenth of one percent (0.001) that the Capacity Ratio is below 85% and is above 74.9%, an amount equal to two-tenths of one percent (0.002) of the Lump Sum Payment for the Measurement Period in question; plus
Tier 4 60.0% - 74.9%	For each one-tenth of one percent (0.001) that the Capacity Ratio is below 75% and is above 59.9%, an amount equal to two and a half-tenths of one percent (0.0025) of the Lump Sum Payment for the Measurement Period in question; plus
Tier 5 50.0% - 59.9%	For each one-tenth of one percent (0.001) that the Capacity Ratio is below 60% and is above 49.9%, an amount equal to three-tenths of one percent (0.003) of the Lump Sum Payment for the Measurement Period in question; plus
Tier 6 49.9% and below (“**Lowest Capacity Bandwidth**”)	For each one-tenth of one percent (0.001) that the Capacity Ratio is below 50%, an amount equal to three and a half-tenths of one percent (0.0035) of the Lump Sum Payment for the Measurement Period in question.

For purposes of determining liquidated damages under this **Section 4.3(a)** (Capacity Test and Liquidated Damages), the starting and end points for the duration of the period that the Facility discharges shall be rounded to the nearest MWh. Each Party agrees and acknowledges that (i) the damages that Company would incur if the Seller fails to achieve the Capacity Performance Metric for a Measurement Period would be difficult or impossible to calculate with certainty and (ii) the aforesaid liquidated damages are an appropriate approximation of such damages.

EXAMPLE: The following is an example calculation of liquidated damages for the Capacity Performance Metric and is included for illustrative purposes only. Assume the following:

- The Maximum Rated Output for the Facility is 25 MW.
- A Capacity Test was conducted and the Facility was measured to have discharged 97.5 MWh
- Contract Capacity = 25 MW x 6 hours = 150 MWh
- Capacity Ratio = MWh Discharged ÷ Contract Capacity = 97.5 MWh ÷ 150 MWh = 0.65
- LD = [((1 – 0.950) x 1) + ((0.950 – 0.850) x 1.5) + ((0.850 – 0.750) x 2 + ((0.750 – 0.65) x 2.5] x Lump Sum Payment for the Measurement Period in question
- = 0.65 x Lump Sum Payment for the Measurement Period in question

4.4 Equivalent Availability Factor Performance Metric.

(a) Annual Equivalent Availability Factor and Liquidated Damages. For each Measurement Period following the Commercial Operations Date, an Annual Equivalent Availability Factor ("**Annual EAF**") shall be calculated as set forth in **Attachment U** (Annual Equivalent Availability Factor). If the Annual EAF for such Measurement Period is less than **97%**[17] (the "**EAF Performance Metric**"), Seller shall pay, and Company shall accept, as

[17] The Self Build Team proposes to change this value from 97% to 96%, to adequately account for maintenance outage requirements. This change would also affect the Tier 1 parameters listed in the Table included in this Section 4.4.

liquidated damages for such shortfall, the amount set forth in the following table (on a progressive basis) upon proper demand at the end the current Measurement Period:

Annual Equivalent Availability Factor	**Liquidated Damage Amount**
Tier 1 85.0% - 96.9%	For each one-tenth of one percent (0.001) by which the Annual EAF falls below 97% but equal to or above 85%, an amount equal to one-tenth of one percent (0.001) of the Lump Sum Payment for the Measurement Period in question; plus
Tier 2 80.0% - 84.9%	For each one-tenth of one percent (0.001) by which the Annual EAF falls below 85% but equal to or above 80%, an amount equal to two-tenths of one percent (0.002) of the Lump Sum Payment for the Measurement Period in question; plus
Tier 3 75.0% - 79.9%	For each one-tenth of one percent (0.001) by which the Annual EAF falls below 80% but equal to or above 75%, an amount equal to three-tenths of one percent (0.003) of the Lump Sum Payment for the Measurement Period in question; plus
Tier 4 Below 75.0%	For each one-tenth of one percent (0.001) by which the Annual EAF falls below 75%, an amount equal to four-tenths of one percent (0.004) of the Lump Sum Payment for the Measurement Period in question.

Such liquidated damages will be passed through to customers through the Company's Power Purchase Adjustment Clause.

For purposes of determining liquidated damages under this **Section 4.4(a)** (Annual Equivalent Availability Factor and Liquidated Damages), the Annual EAF for the Measurement Period in question shall be rounded to the nearest one-tenth of one percent (0.001). Each Party agrees and acknowledges that (i) the damages that Company would incur if the Seller fails to achieve the EAF Performance Metric for a Measurement Period would be difficult or impossible to calculate with certainty and (ii) the aforesaid liquidated damages are an appropriate approximation of such damages.

4.5 Equivalent Forced Outage Factor Performance Metric.

(a) Annual Equivalent Forced Outage Factor and Liquidated Damages. For each Measurement Period following the Commercial Operations Date, the Facility shall maintain an Annual Equivalent Forced Outage Factor ("**Annual EFOF**") of not more than 4% (the "**EFOF Performance Metric**") as calculated as set forth in **Attachment V** (Annual Equivalent Forced Outage Factor). If the EFOF for such Measurement Period exceeds the EFOF Performance Metric, Seller shall pay, and Company shall accept, as liquidated damages for exceeding the EFOF Performance Metric, the amount set forth in the following table (on a progressive basis) upon proper demand by the Company at the end of the Measurement Period in question:

Annual Equivalent Forced Outage Factor	**Liquidated Damage Amount**
0.0% - 4.0%	-0-
4.1% - 6.9%	For each one-tenth of one percent (0.001) that the Annual EFOF is above 4.0% but less than 7.0%, an amount equal to two-tenths of one percent (0.002) of the Lump Sum Payment for the Measurement

	Period in question; plus
7.0% and above	For each one-tenth of one percent (0.001) that the Annual EFOF is above 6.9%, an amount equal to four-tenths of one percent (0.004) of the Lump Sum Payment for the Measurement Period in question.

Such liquidated damages will be passed through to customers through the Company's Power Purchase Adjustment Clause.

For purposes of determining liquidated damages under this **Section 4.5(a)** (Annual Equivalent Forced Outage Factor and Liquidated Damages), the Annual EFOF for the Measurement Period in question shall be rounded to the nearest one-tenth of one percent (0.001). Each Party agrees and acknowledges that (i) the damages that Company would incur if the Seller fails to achieve the EFOF Performance Metric for a Measurement Period would be difficult or impossible to calculate with certainty and (ii) the aforesaid liquidated damages are an appropriate approximation of such damages.

For example, if the Annual EFOF was 4.1% as calculated in the example in **Attachment V** (Annual Equivalent Forced Outage Factor) attached hereto and the Lump Sum Payment for the Measurement Period in question is $1,000,000, the liquidated damages would be $2,000, calculated as follows:

4.1% - 4.0% = 0.1%

$1,000,000 x .002 = $2,000

$2,000 x 1 = $2,000

4.6 Round Trip Efficiency Test; Liquidated Damages.

(a) RTE Test and Liquidated Damages. For each Measurement Period following the Commercial Operations Date, the Facility shall be required to complete a RTE Test or otherwise demonstrate satisfaction of the RTE Performance Metric, as more fully set forth in **Attachment T** (Facility Tests) to this Agreement. For each Measurement Period for which the Facility fails to demonstrate that it satisfies the RTE Performance Metric, Seller shall pay, and Company shall accept, as liquidated damages for such shortfall, in the amount to be calculated as provided in this **Section 4.6(a)** (RTE Test and Liquidated Damages), upon proper demand at the end the Measurement Period in question.

The RTE Performance Metric is 83% as measured at the Point of Interconnection.

The liquidated damages threshold ("**LDT**") is equal to the RTE Performance Metric minus 2 percentage points.

The Selected RTE Test is the RTE Test that came closest to satisfying the RTE Performance Metric during the BESS Measurement Period in question.

Seller shall be liable for liquidated damages if:

$$(PM - RTE\ Ratio) * 100 > 2\%$$

Where:

PM = RTE Performance Metric stated as percentage

RTE Ratio = RTE Ratio from Selected RTE Test stated as percentage

For each percentage point by which the RTE Ratio is below the LDT, Seller shall pay, and Company shall accept, liquidated damages in an amount equal to two-tenths of one percent (0.002) of the Lump Sum Payment for the Measurement Period in question.

Each Party agrees and acknowledges that (i) the damages that Company would incur if the Seller fails to achieve the RTE Performance Metric for a Measurement Period would be difficult or impossible to calculate with certainty and (ii) the aforesaid liquidated damages are an appropriate approximation of such damages.

4.7. Limitation on Liquidated Damages.

(b) Limitation on Liquidated Damages. Notwithstanding any other provision of this Agreement to the contrary, the aggregate liquidated damages paid by Seller during each Contract Year for the Performance Metrics LDs, shall not exceed the total of twelve (12) monthly Lump Sum Payments.

Article 8: CHARGING ENERGY OBLIGATIONS

Except as otherwise set forth in this **Article 8** (Charging Energy Obligations) or as expressly set forth in this Agreement, following the Commercial Operations Date, Company shall be responsible for and bear the cost of delivering all of the Charging Energy for the Facility to the Point of Interconnection. So long as the State of Charge is less than 100%, Seller shall take all actions necessary to accept the Charging Energy, as delivered by Company by manual dispatch or automatic signals, at and from the Point of Interconnection as part of making available to Company the Facility's Energy Storage Services in accordance with the terms of this Agreement and Company tariffs, including, without limitation, maintenance, repair or replacement of equipment in Seller's possession or control used to deliver the Charging Energy to the Facility.

Seller shall only use the Charging Energy for Company's benefit in accordance with the terms of this Agreement.

Article 11: CONSTRUCTION PERIOD AND MILESTONES

11.2 Monthly Progress Report[18].

Commencing upon the PUC Approval Date, Seller shall submit to Company, on the tenth (10th) Business Day of each calendar month until the Commercial Operations Date, a progress report for the prior month in a form acceptable to Company. These progress reports shall notify Company of the current status of each Construction Milestone. Seller shall include in any Monthly Progress Report a list of all letters, notices, applications, approvals, authorizations and filings referring or relating to Governmental Approvals, and shall provide any such documents as may be reasonably requested by Company. In addition, Seller shall advise Company, as soon as reasonably practicable, of any problems or issues of which Seller is aware which could materially impact its ability to timely achieve any Construction Milestone. Seller shall provide Company with any requested documentation to support the achievement of an applicable Construction Milestone within ten (10) Business Days of receipt of such request from Company. Upon the occurrence of a Force Majeure event, Seller shall also comply with the requirements of **Section 17.4** (Satisfaction of Certain Conditions) to the extent such requirements provide for communications to Company beyond those required under this **Section 11.2** (Monthly Progress Report).

[18] Progress reports to be provided internally, according to Company's established project management and governance policies.

11.3 Remedial Action Plan[19].

In the event Seller does not timely achieve a Reporting Milestone, Seller shall submit to Company, within ten (10) Business Days of any such missed Reporting Milestone date, a remedial action plan which shall provide a detailed description of Seller's course of action and plan to achieve (a) the missed Reporting Milestone within ninety (90) Days of the missed Reporting Milestone date; and (b) all subsequent Construction Milestones; provided, that delivery of any remedial action plan shall not relieve Seller of its obligation to timely achieve such Construction Milestones.

11.4 Milestone Dates.

Seller shall achieve each Guaranteed Project Milestone Date or Reporting Milestone Date, subject (to the extent applicable) to the following extensions:

(a) if the PUC Approval Order[20] Date[21] occurs more than one hundred eighty (180) Days after the date the Company files its Application for Approval to Commit Funds in Excess of $2,500,000 for the Purchase and Installation of Item MZ.0050002 Waena Battery Energy Storage System Project, and to Recover Costs through the Major Project Interim Recovery Adjustment Mechanism ("GO7 Application"), Seller and Company shall be

[19] Action plans to be provided internally, according to Company's established project management and governance policies.

[20] For purposes of this Exhibit 1, "PUC Approval Order" shall mean an order from the PUC that does not contain terms and conditions deemed to be unacceptable by Company, and is in a form deemed to be reasonable by Company, in its sole, but nonarbitrary, discretion, ordering: (i) approval of the GO7 Application; (ii) approval of the implementation of the Keāhole BESS Project at a total current estimated cost of $16.9 million as further described in Exhibit 2; (iii) approval of a commitment of funds in excess of $2,500,000 for the Project, net of customer contributions, pursuant to GO7; (iv) approval of the proposed accounting and ratemaking treatment for the Project, as further described in the GO7 Application; (v) determination that a public hearing is not required, pursuant to HRS Section 269-27.5; (vi) approval of the construction of the 69kV sub-transmission line for the Project above the surface of the ground, pursuant to HRS Section 269-27.6(a); and (vii) approval of the terms set forth in this Exhibit 1.

[21] If the Company determines, not later than thirty-five (35) Days after the issuance of a PUC order approving the GO7 Application, that the conditions for a PUC Approval Order have been satisfied, the date of the issuance of the PUC Approval Order shall be the "PUC Approval Order Date."

entitled to an extension of the Guaranteed Project Milestone Dates, Reporting Milestone Dates, Seller's Conditions Precedent Dates and Company Milestone Dates equal to the number of Days that elapse between the end of the aforesaid 180-Day period and the PUC Approval Order Date; provided, that in no event will the Guaranteed Commercial Operations Date be extended beyond April 2025;

(b) if the failure to achieve a Construction Milestone by the applicable Guaranteed Project Milestone Date or Reporting Milestone Date is the result of Force Majeure (which, for purposes of this **Section 11.4(b)** excludes any delay in obtaining the PUC Approval Order because that contingency is addressed in **Section 11.4(a)** above), and if and so long as the conditions set forth in **Section 17.4** (Satisfaction of Certain Conditions) are satisfied, such Guaranteed Project Milestone Date or Reporting Milestone Date shall be extended by a period equal to the lesser of three hundred sixty-five (365) Days or the duration of the delay caused by the Force Majeure; or

(c) if the failure to achieve a Guaranteed Project Milestone by the applicable Guaranteed Project Milestone Date is the result of any failure by Company in the timely performance of its obligations under this Agreement, including achievement of its Company Milestones by the Company Milestone Dates as set forth on **Attachment K-1** (Seller's Conditions Precedent and Company Milestones), as such dates may be extended in accordance with **Section 11.4** (Milestone Dates) and **Section 11.5** (Company Milestones), Seller shall, provided Seller has satisfied Seller's Conditions Precedent set forth in **Attachment K-1** (Seller's Conditions Precedent and Company Milestones) by the respective Seller's Conditions Precedent Date set forth in said **Attachment K-1**, be entitled to an extension of such Guaranteed Project Milestone Date equal to the duration of the period of delay directly caused by such failure in Company's timely performance. Such extension on the terms described above shall be Seller's sole remedy for any such failure by Company. For purposes of this **Section 11.4(c)**, Company's performance will be deemed to be "timely" if it is accomplished within the time period specified in this Agreement with respect to such performance or, if no time period is specified, within a reasonable period of time. If the performance in question is Company's review of plans, the determination of what is a "reasonable period of time" will take into account Company's past practices in reviewing and commenting on plans for similar facilities.

11.5 Company Milestones.

Company's obligation to achieve the Company Milestones is contingent upon Seller completing the Seller's Conditions Precedent set forth in **Attachment K-1** (Company Milestones and Seller's Conditions Precedent). Company shall achieve each of the Company Milestones by the date set forth for such Company Milestones in **Attachment K-1** (Seller's Conditions Precedent and Company Milestones) of this Agreement (each such date, a "**Company Milestone Date**"), as such date may be extended in accordance with **Section 11.4** (Milestone Dates) and this **Section 11.5** (Company Milestones); provided, however in the event Seller does not complete a Seller's Condition Precedent on or before the applicable date set forth in **Attachment K-1** (Seller's Conditions Precedent and Company Milestones) (each such date, a "**Seller's Conditions Precedent Date**"), subject to the extensions set forth in **Section 11.4** (Milestone Dates), Company shall be entitled to an extension as follows: (i) for the commencement of Acceptance Testing, the new Company Milestone Date shall be as set forth in clause "(gg)" of **Section 2(f)(i)** of **Attachment G** (Company-Owned Interconnection Facilities); and (ii) for any other Company Milestone Date, the extension shall be for the period of time reasonably necessary to meet any such Company Milestone Date adversely affected by Seller's failure, which extension shall be no shorter than a day-for-day extension.

11.6 Damages.

(a) Daily Delay Damages.

(i) If a Guaranteed Project Milestone (other than Commercial Operations) has not been achieved by the applicable Guaranteed Project Milestone Date, as extended as provided in **Section 11.4** (Milestone Dates), Company shall collect and Seller shall pay liquidated damages in the amount of $11,111.11 ("**Daily Delay Damages**") for each Day following the applicable Guaranteed Project Milestone Date, as extended in accordance with **Section 11.4** (Milestone Dates); provided, however, that the number of Days for which Company shall collect and Seller shall pay Daily Delay Damages for a failure to achieve a Guaranteed Project Milestone by the Guaranteed Project Milestone Date shall not exceed sixty (60) Days for each such missed Guaranteed Project Milestone Date (the "**Construction Delay LD Period**"). **[Note: Daily Delay Damages = Contract Capacity x $50/kW ÷ 180 Days]**

(ii) If the Commercial Operations Date has not been achieved by the Guaranteed Commercial Operations Date, as extended as provided in **Section 11.4** (Milestone Dates), in addition to any Daily Delay Damages collected pursuant to **Section 11.6(a)(i)**, Company shall collect and Seller shall pay Daily Delay Damages for each Day following the Guaranteed Commercial Operations Date, as such date may be extended in accordance with **Section 11.4** (Milestone Dates); provided that the number of Days for which Company shall collect and Seller shall pay Daily Delay Damages for failing to timely achieve the Commercial Operations Date shall not exceed one hundred eighty (180) Days (the "**COD Delay LD Period**").

Article 12

DISPATCHING AND CHARGING THE FACILITY; SCHEDULING

12.1 Dispatching and Charging the Facility.

(a) Company's Exclusive Rights. Company shall have the exclusive right, through supervisory equipment or otherwise, to direct and control the provision of all aspects of the Energy Storage Services, at any time, as it deems appropriate in its reasonable discretion, subject only to and consistent with Good Engineering and Operating Practices, the operational and performance standards requirements set forth in **Section 3** (Performance Standards) of **Attachment B** (Facility Owned by Seller), and Seller's maintenance schedule determined in accordance with **Section 12.2** (Seller's Maintenance Schedule) ("**Company Dispatch/Charge**"). Seller shall make the full capability of the Facility available for Company Dispatch/Charge. Company Dispatch/Charge will be under the direction of the Company System Operator or by remote computerized control by the Energy Management System provided in **Section 1(g)** (Active Power Control Interface) of **Attachment B** (Seller's Facility), in each case at Company's reasonable discretion, and in accordance with the Performance Standards.

(b) Failure to Comply; Seller-Attributable Unavailability. Company may require deration or outage in response to the Facility's failure to comply with Company Dispatch/Charge or to any conditions of Seller-Attributable Unavailability. A deration or outage required by Company pursuant to the preceding sentence shall be considered an Unplanned Deration and shall "count against" Seller for the purpose of calculating the Annual EAF and Annual EFOF until the conditions that led to the deration or outage are resolved by Seller and Seller notifies Company of same. If, after such notification, Company attempts to dispatch the Facility and determines that such conditions that led to the deration or outage are not resolved, all time from the notice of resolution to actual resolution shall be revised as continuance of the deration or outage. If Seller requests confirmation from Company that Seller's actions to resolve such conditions that led to the deration or outage were successfully completed, then Company shall use reasonable efforts to respond to such request within three (3) Business Days in writing (with Email being acceptable) to allow Seller the opportunity to take further appropriate corrective actions if needed.

12.2 Seller's Maintenance Schedule.[22]

(a) Quarterly Schedule. By each March 1, June 1, September 1 and December 1 (as applicable, subsequent to the Commercial Operations Date), Seller shall provide to Company, in the form requested by Company, a projection of maintenance outages and estimated reductions in capacity for the next calendar quarter. Seller shall provide Company with prompt written notice of any deviation from its quarterly maintenance schedule but in any case, Seller shall provide such written notice not less than one (1) week prior to commencing any such rescheduled maintenance event. During any scheduled or rescheduled maintenance event, Seller shall provide updates to Company's operating personnel in the event there are any delays or changes to the proposed schedule, and shall promptly respond to any requests from Company for updates regarding the status of such maintenance event.

(b) Annual Schedule. By each June 30 subsequent to the Commercial Operations Date, Seller shall submit to Company, in the form requested by Company, a schedule of maintenance outages which will reduce the capacity of the Facility by **[Drafting Note: the lower of five (5) MW or 10% of Allowed Capacity]** or more for the next two-year period, beginning with January of the following year. Such annual schedule shall state the proposed dates and

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[22] Notification, scheduling, and execution of system maintenance plans to be conducted according to Company's established internal policies.

durations of scheduled maintenance, the scope of work for the maintenance and the estimated reductions in capacity for each projected maintenance event. Company shall review the maintenance schedule for the two-year period and inform Seller in writing no later than December 1 of the same year of Company's concurrence or requested revisions, which Seller shall agree to unless, in Seller's judgment, such proposed revisions will void or violate any warranties of equipment that is part of, or used in connection with, the Facility or violate any long-term service agreement with respect to such equipment; provided, that, in each such case, Seller shall promptly notify Company thereof, and Seller and Company shall endeavor to reach a mutually satisfactory resolution of the matter in question.

12.3 Seller's Notification Obligations.

When Seller learns that any of its equipment will be removed from or returned to service, and any such removal or return may affect the ability of the Facility to make the Energy Storage Services available to Company, Seller shall notify Company as soon as practicable and any unit shut-down shall be coordinated with Company in advance to the extent practicable.

12.4 Outage Costs.

Seller shall use commercially reasonable efforts to mitigate any losses of Energy due to an outage such that losses are limited to the Facility's standby consumption, specifically, no more than [ ][23] kWh per twenty four (24) hours of outage duration.

Article 17 Satisfaction of Certain Conditions

17.1 Definition of Force Majeure.

The term "**Force Majeure**" as used in this Agreement means any occurrence that:

(a) In whole or in part delays or prevents a Party's performance under this

[23] Acceptable standby consumption limits to be determined upon final design.

Agreement;

(b) Is not the direct or indirect result of the fault or negligence of that Party;

(c) Is not within the control of that Party notwithstanding such Party having taken all reasonable precautions and measures in order to prevent or avoid such event; and

(d) The Party has been unable to overcome by the exercise of due diligence.

17.2 Events That Could Qualify as Force Majeure.

Subject to the foregoing, events that could qualify as Force Majeure include, but are not limited to, the following:

(a) acts of God, flooding, lightning, landslide, earthquake, fire, drought, explosion, epidemic, quarantine, storm, hurricane, tornado, volcano, other natural disaster or unusual or extreme adverse weather-related events;

(b) war (declared or undeclared), riot or similar civil disturbance, acts of the public enemy (including acts of terrorism), sabotage, blockade, insurrection, revolution, expropriation or confiscation; or

(c) except as set forth in **Section 17.3(i)**, strikes, work stoppage or other labor disputes (in which case the affected Party shall have no obligation to settle the strike or labor dispute on terms it deems unreasonable).

17.3 Exclusions From Force Majeure.

Force Majeure, however, does not include any of the following:

(a) any acts or omissions of any third party, including, without limitation, any vendor, materialman, customer, or supplier of Seller, unless such acts or omissions are themselves caused by an event of Force Majeure;

(b) any full or partial reduction in the availability of the Facility to provide the

Energy Storage Services in response to Company Dispatch/Charge that is caused by or arises from either (i) a mechanical or equipment breakdown, or other mishaps, events or conditions attributable to normal wear and tear, unless such mishap is caused by Force Majeure; or (ii) any action or inaction of a third party, including but not limited to any vendor or supplier of the Seller or Company, except to the extent such action or inaction is due to Force Majeure;

(c) changes in market conditions that affect the cost of the Seller's supplies, or that otherwise render this Agreement uneconomic or unprofitable for the Seller;

(d) Seller's inability to obtain Governmental Approvals or Land Rights for the construction, ownership, operation or maintenance of the Facility, or Seller's loss of any such Governmental Approvals or Land Rights once obtained;

(e) Seller's inability to obtain sufficient fuel, power or materials to operate the Facility, except if Seller's inability to obtain sufficient power or materials is caused solely by an event of Force Majeure;

(f) Seller's failure to obtain additional funds, including funds authorized by a state or the federal government or agencies thereof, to supplement the payments made by Company pursuant to this Agreement;

(g) a forced outage except where such forced outage is caused by an event of Force Majeure;

(h) litigation or administrative or judicial action pertaining to Seller's interest in this Agreement, the Site, the Facility, the Land Rights, any Governmental Approvals, or the construction, ownership, operation or maintenance of the Facility, the Company-Owned Interconnection Facilities or the Company System;

(i) A strike, work stoppage, or labor dispute limited only to any one or more of the

Indemnified Seller Parties or any other third party employed by Seller to work on the Facility.

17.4 Satisfaction of Certain Conditions.

Subject to **Article 11** (Construction Period and Milestones), if, because of Force Majeure, either Party is unable to perform its obligations under this Agreement, such Party shall be excused from whatever performance is affected by the Force Majeure only to the extent so affected; provided:

(a) the non-performing Party gives the other Party, no more than five (5) Days after the non-performing Party becomes aware or should have become aware of the Force Majeure condition or event, but in any event no later than thirty (30) Days after the Force Majeure condition or event begins, written notice (the "**Force Majeure Notice**") stating that the non-performing Party considers such condition or event to constitute Force Majeure and describing the particulars of such Force Majeure condition or event, including the date the Force Majeure commenced;

(b) the non-performing Party gives the other Party, within fourteen (14) Days Force Majeure Notice was or should have been provided, a written explanation of the Force Majeure condition or event and its effect on the non-performing Party's performance, which explanation shall include evidence reasonably sufficient to establish that the occurrence constitutes Force Majeure;

(c) the suspension of performance is of no greater scope and of no longer duration than is required by the Force Majeure;

(d) the non-performing Party exercises commercially reasonable efforts to remedy its inability to perform and provides written weekly progress reports to the other Party describing actions taken to end the Force Majeure; and

(e) when the condition or event of Force Majeure ends and the non-performing Party is able to resume performance of its obligations under this Agreement, that Party shall give the other Party written notice to that effect.

ATTACHMENT B

FACILITY OWNED BY SELLER

1. The Facility.

(a) Drawings, Diagrams, Lists, Settings and As-Builts.

(i) Single-Line Drawing, Interface Block Diagram, Relay List, Relay Settings and Trip Scheme. A preliminary single-line drawing (including notes), Interface Block Diagram, relay list, relay settings, and trip scheme of the Facility shall, after Seller has obtained prior written consent from Company, be attached to this Agreement on the PUC Approval Date as **Attachment E** (Single-Line Drawing and Interface Block Diagram) and **Attachment F** (Relay List and Trip Scheme). A final single-line drawing (including notes), Interface Block Diagram, relay list and trip scheme of the Facility shall, after having obtained prior written consent from Company, be labeled the "Final" Single-Line Drawing, the "Final" Interface Block Diagram and the "Final" Relay List and Trip Scheme and shall supersede **Attachment E** (Single-Line Drawing and Interface Block Diagram) and **Attachment F** (Relay List and Trip Scheme) to this Agreement and shall be made a part hereof on the Commercial Operations Date. After the Commercial Operations Date, no changes shall be made to the "Final" Single-Line Drawing, the "Final" Interface Block Diagram and the "Final" Relay List and Trip Scheme without the prior written consent of Seller and Company. The single-line drawing shall expressly identify the Point of Interconnection of Facility to Company System.

(g) Active Power Control Interface.

(i) Seller shall provide and maintain in good working order all equipment, computers and software associated with the control system (the "**Active Power Control Interface**") necessary to interface the Facility active power controls with the Company System Operations Control Center for real power control of the Facility by the Company System Operator.

The detailed design will be tailored to the specific resource type and configuration to achieve the functional requirements of the Facility.

The Active Power Control Interface will be used to control the net real power export (or import, as applicable) from the Facility for load following, system balancing, energy arbitrage, and/or supplemental frequency control as required under this **Attachment B** (Facility Owned by Seller).

For facilities with grid charging storage, the Active Power Control interface may also direct the charging/discharging of energy from the BESS.

The Facility real power output (or import, if storage charging is enabled) will automatically adjust to a change in frequency in accordance with the frequency response requirements provided in this **Attachment B** (Facility Owned by Seller).

(ii) Company shall review and provide prior written approval of the design for the Active Power Control Interface to ensure compatibility with Company's centralized control systems and use of Facility available energy and storage capabilities. To ensure such continued compatibility, Seller shall not materially change the approved design without Company's prior review and written approval. This will include design description and parameters for the Seller's control system(s), which determine provision of net real power the BESS storage, and charging of the BESS storage, in response to the Active Power Control signal or signals.

(iii) The Active Power Control Interface shall include, but not be limited to, a demarcation cabinet, ancillary equipment and software necessary for Seller to connect to Company's Telemetry and Control, located in Company's portion of the Facility switching station which shall provide the control signals to the Facility and send feedback status to the Company System Operations Control Center. The control type shall be analog output (set point) or raise/lower controls and will be established by the Company prior to final design approval.

(iv) The Active Power Control Interface shall also include provision for feedback points from the Facility indicating active power target in MW for the Active Power Control signal(s). The Facility shall provide the MW target feedback to the Company SCADA system immediately upon receiving the respective control signal from the Company.

(v) Seller shall provide to the telemetry interface analogs for the gross production of the energy resource(s) at the Facility (for example, DC or AC MW production of the Variable Resource generator(s), depending on design; gross DC MW of the BESS, etc.) Seller shall also provide the total net AC MW production at the Point of Interconnection.

(vi) The Active Power Control Interface shall provide for remote control of the real-power output of the Facility by the Company at all times. If the Active Power Control Interface is unavailable or disabled, the Facility may not export electric energy to Company and the Facility shall be deemed to be in Seller-Attributable Unavailability status, unless the Company, in its sole discretion, agrees on an alternate means of dispatch. If Seller fails to provide such remote control capability (whether temporarily or throughout the Term), then, notwithstanding any other provision of this **Attachment B** (Facility Owned by Seller), Company shall have the right to derate or disconnect the entire Facility during those periods that such control capability is not provided and the Facility shall be deemed to be in Seller-Attributable Unavailability status for such periods.

(vii) The rate at which the Facility changes net real power in response to the active power control shall not be less than the greater of 2 MW per minute or 10% of the Facility capacity per minute, and shall make available through agreed parameters, such faster ramp as the installed equipment can support. The Facility's Active Power Control Interface will be used by Company to control the rate at which electric energy is changed to achieve the active power limit for load-following and regulation. The Facility will respond to the active power control request immediately with an echo of the set point and measurable change within the 4 second control cycle.

(viii) The Facility shall accept the following controls related to active power and frequency response to or from the Company centralized control system:

- Power Reference Setpoint from Company (based on the input to the Facility, from the Active Power Control Interface): The Facility output shall match this setting from the BESS so long as it can be supported by the variable resource and/or BESS State of Charge (Power Possible does not change). This net output should be accurate within +/- 0.1 MW under normal frequency conditions. This setpoint will be modified as appropriate in the controls by the appropriate frequency response consistent with **Section 1(g)(xi)** (Active Power – Frequency Response (DROOP)), **Section 1(g)(xii)** (Dynamic Active Power – Frequency Performance), and **Section 1(g)(xiii)** (Alternate Active Power / Frequency Response Modes) of this **Attachment B** (Facility Owned by Seller).

- For variable energy resources: The Facility shall include Variable Resource Enable/Disable control. When "Disable" is selected, the Facility shall ramp down, shutdown, and leave offline variable resource generators. When "Enable" is selected, the Facility variable resource generators can start up, ramp up, and remain in normal operations subject to Company active power dispatch.

- From Company: Frequency Response Mode (DROOP, FFR, isochronous) state (where alternate modes of operation are required).

- From Seller:

  - [For Facilities with a BESS and where required]: Capacity allocation to each mode of operation where ability to allocate capacity to different modes of operation is required (e.g., to allocate a portion of capacity to fast frequency response) and telemetered data and controls necessary to determine state of charge, and gross MW and Mvar contribution, etc. operationally required for each segmented use.

  - Power Possible (Available maximum capacity): See above, instantaneous limit for available energy, represents max level the Facility can produce under present resource, BESS State of Charge (if applicable) and equipment conditions. This is used as upper limit for Company Dispatch.

  - For Variable Energy Resources: max level the variable generation resources can produce under present variable resource and equipment conditions.

  - Minimum Sustained Limit: Minimum output level the Facility can be reduced to continuously without delay (ecomn). For projects with BESS: If BESS charging from the grid is permitted, and charging capacity is available, this will be a negative value.

- Minimum Transient Limit (for frequency response, regulation) (lfcmn). For projects with BESS: If BESS charging from the grid is permitted, and charging capacity is available, this will be a negative value.
- Maximum Dispatchable Ramp Rate: Controlled ramp rate available for controlled changes in output.
- For projects with a BESS, Seller shall also provide the following:
  - BESS potential (BESS State of Charge and projected number of hours at present dispatch, minimum dispatch, and maximum dispatch).
  - Frequency Response Mode (DROOP, FFR, isochronous) state (where alternate modes of operation are required).
  - Capacity allocation to each mode of operation (to allow FFR and Droop allocation).

(ix) Seller shall not override Company's active power controls without first obtaining specific approval to do so from the Company System Operator unless there is a system emergency. Disabling of the remote Active Power Control shall initiate telemetry notification to the Company.

(x) The requirements of the Active Power Control Interface may be modified as mutually agreed upon in writing by the Parties.

Active Power Communications between Company and Seller

Company will receive and send AGC Set-Point and related data through the communications interface in accordance with Company standards. The data points covered under this Agreement, as described below, may overlap with data requirements described elsewhere.

AGC Data Points to be sent from Seller to Company via SCADA

The following data points will be transmitted via SCADA from Seller to Company and represent Facility level data

Description	Units
AGC Set-Point (echo)	MW
Power demand	MW
Actual power	MW
Power Possible	MW
Actual reactive power	Mvars
Average Voltage	Kv
Variable Generation potential	MW
[Wind only] Number of turbines online and running	Integer

BESS State of Charge	Pct
[PV only] Inverters online	Integer
Facility duration at current output	HRS
AGC Status	Remote/Local
[For facilities with alternate modes of frequency response] Indication of Frequency Response Mode	Integer FFR, Droop, ISOCH

Response times and limitations of Facility in regards to Active Power Control

The following protocols outline the expectations for responding to the AGC Set-Point.

Frequency of Changes. Company may send a new AGC Set-Point to the Facility at up to the AGC control cycle (present 4 seconds).

Range of AGC Set-Point. The range of set point values can be between 0% and 100% of Power Possible. For projects offering grid-charging storage, negative set-point values may be required.

Backup Communications

In the event of an AGC failure, Company and Seller shall communicate via telephone, or other method mutually agreeable between the Parties, in order to correct the failure

(xi) Active Power - Frequency Response (DROOP). The Facility shall provide a primary frequency response with a frequency droop characteristic reacting to system frequency at the Point of Interconnection in both the overfrequency and underfrequency directions except as limited by the minimum and maximum available capacity and energy potential at the time of the event including BESS state of charge. This response must be timely and sustained rather than injected for a short period and then withdrawn. For over-frequency events, response may include absorption through charging (as applicable under the terms of this Agreement). Seller shall provide minimum operational limits for each online resource and the Facility for primary frequency response.

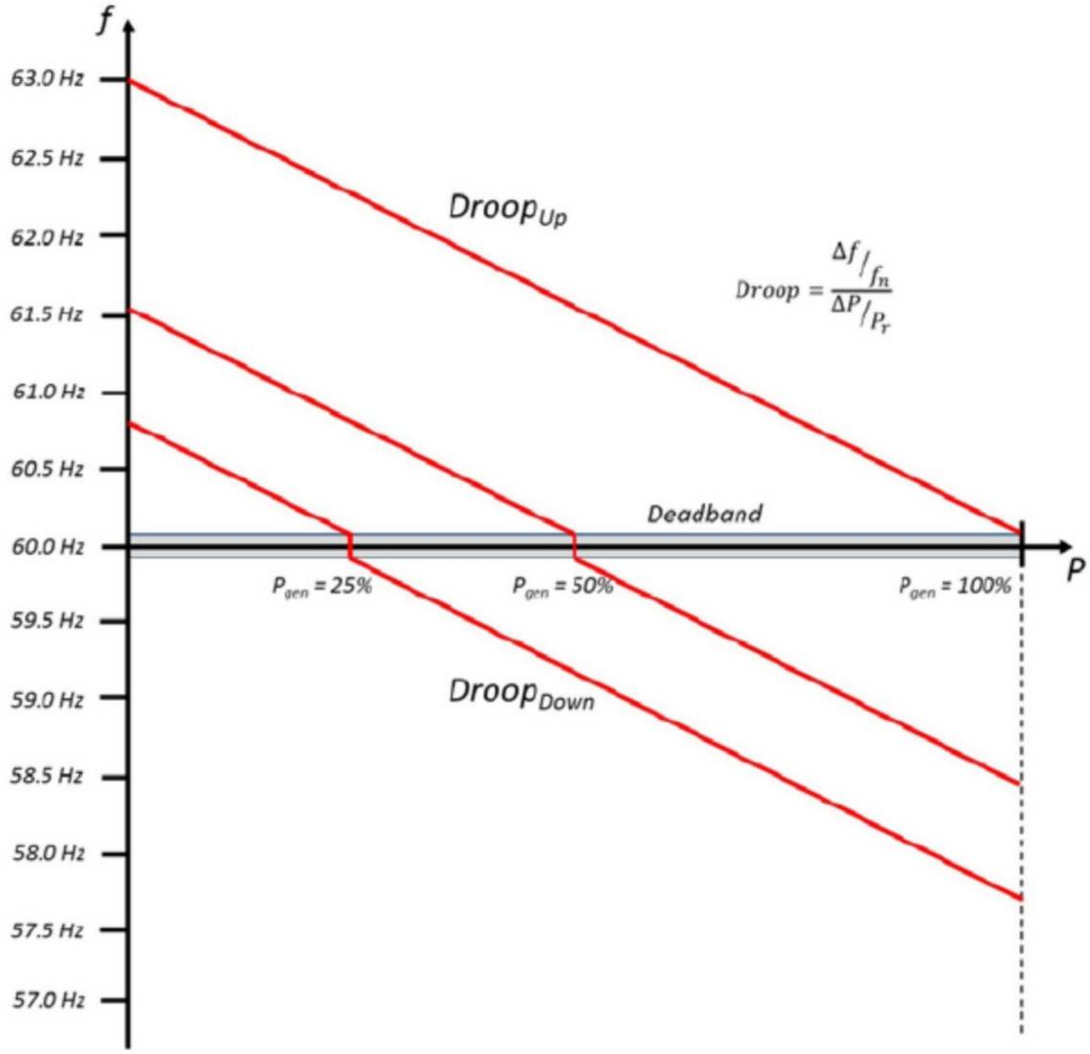
Frequency will be calculated over a period of time (e.g., three to six cycles, or other period as specified by Company), and filtered to take control action on the fundamental frequency component of the calculated signal. Calculated frequency may not be susceptible to spikes caused by phase jumps on the Company system.

The active power-frequency control system, and overall response of the inverter-based resource (plant), must meet the following performance aspects (see figure below):

The active power-frequency control system shall have an adjustable proportional droop characteristic with a default value of [4%] percent. The droop setting shall permit a setting from 0.1% to 10%. This setting shall be changed upon Company's written request as necessary for grid droop response coordination. The droop setting shall be tunable and may be specified during commissioning. The droop shall be a permanent value based on Pmax (maximum nominal active power output of the plant) and Pmin (typically 0 for an inverter based resource). This keeps the proportional droop constant across the full range of operation. The curve for an inverter-based BESS may include the negative active power quadrant of this curve. The droop response must include the capability to respond in both the upward (underfrequency) and downward (overfrequency) directions. Frequency droop will be based on the difference between maximum nameplate active power output (Pmax) and zero output (Pmin) such that the [4%] percent droop line is always constant for a resource.

Seller shall make commercially reasonable efforts to provide frequency response without a deadband, but in any case, not to exceed +/- 0.0166 Hz. If the active power-frequency control system has a deadband, it shall be a nonstep deadband that is adjustable between 0 Hz and the full frequency range of the droop characteristic with a default value not to exceed ± 0.036 Hz. (Nonstep deadband is where the change in active power output starts from zero deviation on either side of the deadband.) (Frequency deadband is the range of frequencies in which the unit does not change active power output.)

Inverter-based resources may consider a small hysteresis characteristic where linear droop meets any deadband to reduce dithering of inverter output when operating near the edges of the deadband. The hysteresis range may not exceed ± 0.005 Hz on either side of the deadband. If measurement resolution is not sufficient to measure this frequency, hysteresis may not be used.



Active Power - Frequency Control Characteristic

Nominal System Frequency is 60.00 Hz.

The closed-loop dynamic response of the active power-frequency control system of the overall inverter-based resources, as measured at the POI must have the capability to meet or exceed the performance specified in below. Seller shall ensure that the models and parameters for the resources and control equipment are consistent with those provided during the IRS process and that any updates have been provided to the Company reflecting currently implemented settings and configuration.

(xii) Dynamic Active Power-Frequency Performance. For a step change in frequency at the point of measure of the inverter-based resource[24]

Reaction time: The time between a step change in frequency and the time when the resource active power output begins responding to the change shall be less than 500 Ms, or as otherwise specified by Company.[25]

Rise time: The time when the resource has reached 90% of the new steady-state (target) active power output shall be less than 4 seconds, or as otherwise specified by Company.[26]

Settling Time: Time in which the resource has entered into, and remains within, the settling band of the new steady-state active power (target) output shall be less than 10 seconds, or as otherwise specified by Company.

Overshoot: Percentage of the rated active power output that the resource can exceed while reaching the settling band shall be less than 5% or as otherwise specified by Company.[27]

Settling Band: Percentage of rated active power output that the resource should settle to within the settling time shall be less than 2.5%.

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[24] Item may be adjusted based on the Interconnection Requirements Study ("IRS")
[25] Time between step change in frequency and the time to 10 percent of new steady-state value can be used as a proxy for determining this time.
[26] Percentage based on final (expected) settling value.
[27] Percentage based on final (expected) settling value.

When operating in parallel with the Company System, the Facility shall operate with its primary frequency response control in automatic operation and in accordance with Company directions. Notification of changes in the status of the frequency response controls and, where applicable, mode of operation must be provided to the Company System Operator immediately through SCADA telemetry indication.

The Facility frequency response control shall adjust, without intentional delay and without regard to the ramp rate limits in **Section 3(c)** (Ramp Rates) of this **Attachment B** (Facility Owned by Seller), the Facility's net real power export based on frequency deadband and frequency droop settings specified by the Company.

The Facility frequency response control shall increase the net real power export above the Power Reference Setpoint set under **Section 1(g)(viii)** of this **Attachment B** (Facility Owned by Seller) or further decrease the net real power export from the Power Reference Limit in its operations in accordance with the frequency response settings.

The Facility frequency response control shall be in continuous operation unless directed otherwise by the Company.

(xiii) Alternate Active Power/ Frequency Response Modes. The Facility will provide the capability to supply isochronous or fast frequency response modes of operation, in addition to normal droop, which can be set remotely or locally. The control design shall allow for a bumpless transfer between modes of operation.

A. Fast Frequency Response (FFR): This mode of operation will permit the Facility to respond to system frequency disturbances with a fast charge/discharge response in accordance with the fast frequency response droop settings. In this mode of operation, the Facility frequency response is configured to provide fast frequency response, as an alternative setting to the normal steady-state frequency response. When in this mode of operation, the frequency droop characteristics are configured to charge or discharge with a different set of parameters to allow for a faster and larger proportional charge and discharge in response to frequency changes outside of the configurable deadband. The initial parameter settings will be specified by Company following the IRS and additional tuning and adjustment of configurable parameters may be required based on review of response to actual system events. When in FFR mode, when system frequency is within the fast frequency response deadband, the Facility will operate to maintain a percentage state of charge, which is configurable on Company request (i.e., 50%) managed at a charging/discharging rate, also specified by Company.

B. Isochronous / Black Start: The Facility will be capable of operating in a zero droop (isochronous) mode of operation. When in this mode of operation, the frequency droop characteristic will be configured as needed to keep system frequency at a target. In a black start configuration, the target shall be 60 Hz. If isochronous is specified while in operation, the target shall be initialized to the grid frequency and the target increased or decreased from the Company System through the control interface.

1j. **Demonstration of Facility.** Company shall have the right at any time, other than during maintenance or other special conditions communicated by Seller, to notify Seller in writing of Seller's failure, as observed by Company and set forth in such written notice, to meet the operational and performance requirements specified in **Section 1(b)(iii)(I)**, **Section 1(g)**

(Active Power Control Interface) and **Section 3** (Performance Standards) of this **Attachment B** (Facility Owned by Seller), and to require documentation or testing to verify compliance with such requirements. Upon receipt of such notice, Seller shall promptly investigate the matter, implement corrective action and provide to Company, within thirty (30) Days of such notice, a written report of both the results of such investigation and the corrective action taken by Seller; provided, that, if thirty (30) Days is not a reasonable time period to investigate the matter, implement corrective action and provide such written report, Seller shall complete the foregoing within such longer commercially reasonable period of time agreed to by the Parties in writing. If the Seller's report does not resolve the issue to Company's reasonable satisfaction, the Parties shall promptly commission a study to be performed by one of the engineering firms then included on the Qualified Independent Third-Party Consultants List attached to the Agreement as **Attachment D** (Consultants List) to evaluate the cause of the non-compliance and to make recommendations to remedy such non-compliance. Seller shall pay for the cost of the study. The study shall be completed within ninety (90) Days, unless the selected consultant determines such study cannot reasonably be completed within ninety (90) Days, in which case, such longer period of time as the selected consultant determines is necessary to complete such study shall apply. The consultant shall send the study to Company and Seller. Seller (and/or its third-party consultants and contractors), at Seller's expense, shall take such action as the study shall recommend with the objective of resolving the non-compliance. Such recommendations shall be implemented by Seller to Company's reasonable satisfaction no later than forty-five (45) Days from the Day the completed study is issued by the consultant, unless such recommendations cannot reasonably be implemented within forty-five (45) Days, in which case, Seller shall implement such recommendations within such longer commercially reasonable period of time agreed to by the Parties in writing. Failure to implement such recommendations within this period shall constitute a material breach of this Agreement. Unless the aforementioned written report and study are being completed, and any recommendations are being implemented, solely to address Seller's failure to satisfy the requirements of **Section 3(w)** (Round Trip Efficiency) of this **Attachment B** (Facility Owned by Seller), Company shall have the right to declare the Facility derated and in Seller-Attributable Unavailability status until the Seller's aforementioned written report has been completed, any subsequent study commissioned by the Parties has been completed and any recommendations to resolve the non-compliance have been implemented to Company's reasonable satisfaction.

3. Performance Standards.

(a) Reactive Power Control. Seller shall control its reactive power by automatic voltage regulation control. Seller shall automatically regulate voltage at a point, the point of regulation, between the Seller's generator terminal and the Point of Interconnection to be specified by Company, to within 0.5% of a voltage or power factor specified by the Company System Operator to the extent allowed by the Facility reactive power capabilities as defined in **Section 3(b)** (Reactive Power Characteristics) of this **Attachment B** (Facility Owned by Seller)

(b) Reactive Power Characteristics.

(i) The Facility must deliver power up to the Allowed Capacity (MW) at a power factor between 95% lagging and 95% leading to the Company System as illustrated in the generator capability curve(s) attached to this Agreement as **Exhibit B-2**, which represents the Facility Composite (Generator and Energy Storage Capability Curve(s)). Facilities with a BESS with grid charging can operate with negative active power. These facilities shall provide automatic voltage control within their reactive capability while acting as a load (charging, negative active power generation). The automatic voltage control aspects of a BESS shall be seamless across the transition from acting as a generating resource to acting as a load. The Facility must be capable of automatically adjusting reactive control to maintain the bus voltage at the Point of Interconnection to meet the scheduled voltage set point target specified by the Company System Operator and be capable of supplying reactive power at the leading/lagging 0.95 power factor at all active power outputs down to zero active power. The voltage target will be specified remotely by the Company System Operator through the SCADA/EMS. The Facility's voltage set point target must reflect the Company voltage set point target controlled from the SCADA/EMS, without delay. The Facility should not normally operate on a fixed var or fixed power factor unless agreed by Company. The voltage setpoint target and present Facility minimum and maximum reactive power limits based on the Facility Composite capability curve shall be provided to the Company EMS through Company's Telemetry and Control.

(ii) The Facility shall contain equipment able to continuously and actively control the output of reactive power under automatic voltage regulation control reacting to system voltage changes. The response requirements are differentiated for large and small signal disturbance performance characteristics. Small signal disturbances are those that reflect normal variations under non-disturbance conditions, the continuous operation range for voltage ride through: $0.80 \text{ pu} \leq V \leq 1.00 \text{ pu}$ at the point of interconnection. Large disturbance is where the voltage at the point of interconnection falls outside the continuous operating range.

(iii) For small signal disturbances, reaction time between the step change in voltage and the reactive power change shall be less than 500 msec (no intentional time delay). The automatic voltage regulation response speed at the point of regulation shall be such that at least 90% of the initial voltage correction needed to reach the voltage control target will be achieved within 1 second following a step change. The percentage of rated reactive power output that the resource can exceed while reaching the settling band shall be less than five percent (5%).

(iv) Large disturbances: Large disturbances are characterized by voltage falling outside of the continuous operating range. The Facility shall adhere to the following characteristics for large disturbances:

> The response of each generating resource over its full operating range and for all expected grid conditions should be stable. The dynamic performance of each resource should be tuned to provide this stable response. Company will work with Seller to ensure during the interconnection process that each resource supports Company System reliability and provides a stable transient response to grid events.[28]
>
> Inverter-based resources shall operate in closed loop automatic voltage control at all times to support voltage regulation and voltage stability. Either the individual inverters or the plant-level closed loop automatic voltage controller must operate with a relatively fast response characteristic to mitigate steady-state voltage issues from causing dynamic voltage collapse. The plant-level controller may send voltage or reactive power set point changes to the individual inverters relatively fast, or the inverters will respond locally (depending on control architecture).

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[28] The performance specifications described here may need to be modified based on studies performed for specific interconnections to provide a stable response

For a large disturbance step in voltage, measured at the inverter terminals, where voltage falls outside the continuous operating range, the positive sequence component of the inverter reactive current response must meet the performance specifications set forth below. These parameters may be adjusted following additional study and/or operational testing and performance.

Reaction time: Time between the step change in voltage and when the resource reactive power output begins responding to the change. The reaction time shall be less than 16 msec.

Rise time: Time between a step change in control signal input and when the reactive power output changes by 90 percent of its final value. The rise time shall be less than 100 msec.

Overshoot: Percentage of rated reactive current output that the resource can exceed when reaching the settling band. Overshoot will be determined following the IRS such that any overshoot in reactive power response does not cause Company System voltages to exceed acceptable voltage limits. The magnitude of the dynamic response may be requested to be reduced based on stability studies or actual operational data review.

(v) If the Facility does not operate in accordance with **Section 3(b)** (Reactive Power Characteristics) of this **Attachment B** (Facility Owned by Seller), Company may disconnect all or a part of Facility from Company System until Seller corrects its operation (such as by installing supplemental reactive power equipment or additional controls modifications, at Seller's expense).

(c) Ramp Rates. Seller shall ensure that the ramp rate of the Facility is less 2 MW a minute for all conditions other than those under control of the Company System Operator and/or those due to desired frequency response, including start up, depletion of storage charge and resource, locally controlled startup and shut down.

(d) Ride-Through. Ride-Through requires that the resource continues to inject current within the "No Trip" zone of the voltage and frequency ride-through requirements. Unless approved during the Interconnection Requirements Study analysis, resources should not use "momentary cessation" within the ride-through regions for any of the ride-through requirements in this **Attachment B** (Facility Owned by Seller).

(e) Undervoltage Ride-Through. The Facility, as a whole, will meet the following undervoltage ride-through requirements during low voltage affecting one or more of the three voltage phases ("V" is the voltage of any three voltage phases at the Point of Interconnection). For alarm conditions the Facility shall not disconnect from the Company System unless the Facility's equipment is at risk of damage. This is necessary in order to coordinate with the existing Company System.

0.80 pu ≤ V ≤ 1.00 pu	The Facility remains connected to the Company System and in continuous operation.
0.00 pu ≤ V < 0.80 pu	The Facility remains connected to the Company System and in continuous operation for a minimum of 600 milliseconds per event (while "V" remains in this range). The Facility may initiate an alarm if "V" remains in this range for more than 600 milliseconds; the duration of the event is measured from the point at which the voltage drops

below 0.80 pu and ends when the voltage is at or above 0.80 pu. The 600 milliseconds represents a delayed clearing time of 30 cycles plus breaker opening time.

Protective Undervoltage Relaying (27) shall be set to alarm only to meet the above ride-through requirements, and shall not initiate a disconnect from the Company System unless Seller reasonably determines based upon Good Engineering and Operating Practices that the Facility's equipment is at risk of damage. This is necessary in order to coordinate with the existing Company System.

Seller shall have sufficient capacity to fulfill the above mentioned requirements to ride-through subsequent events 300 cycles or more apart, between which the voltage at the POI recovers above 0.80 pu.

(f) Over Voltage Ride-Through. The overvoltage protection equipment at the Facility shall be set so that the Facility will meet the following overvoltage ride-through requirements during high voltage affecting one or more of the three voltage phases (as described below) ("V" is the voltage of any of the three voltage phases at the Point of Interconnection). For alarm conditions the Facility should not disconnect from the Company System unless the Facility's equipment is at risk of damage. This is necessary in order to coordinate with the existing Company System

1.00 pu $<$ V $\leq$ 1.10 pu	The Facility remains connected to the Company System.
1.10 pu $<$ V $\leq$ 1.15 pu	The Facility remains connected to the Company System and in continuous operation no less than 30 seconds; the duration of the event is measured from the point at which

	the voltage increases at or above 1.1 pu and ends when voltage is at or below 1.1 pu.
V > 1.15 pu	The Facility remains connected to the Company System and in continuous operation for as long as possible as allowed by the equipment operational limitations.

Protective Overvoltage Relaying (59) shall be set to alarm only to meet the above ride-through requirements, and shall not initiate a disconnect from the Company System unless Seller reasonably determines based upon Good Engineering and Operating Practices that the Facility's equipment is at risk of damage. This is necessary in order to coordinate with the existing Company System.

(g) Transient Stability Ride-Through. The Facility shall be designed such that the transient stability of Company System is maintained for normally cleared and secondarily cleared faults. The Facility will be required to remain connected through anticipated rates of change of frequency

(h) Reserved.

(i) Underfrequency Ride-Through. The Facility shall meet the following underfrequency ride-through requirements during an underfrequency disturbance, and export of power shall continue with output adjusted as appropriate for Facility droop response consistent with **Section 1(g)(xi)** (Active Power – Frequency Response (DROOP)), **Section 1(g)(xii)** (Dynamic Active Power – Frequency Performance), and **Section 1(g)(xiii)** (Alternate Active Power / Frequency Response Modes) of this **Attachment B** (Facility Owned by Seller) ("f" is the Company System frequency at the Point of Interconnection):

$57.0\,\text{Hz} \leq f \leq 60.0\,\text{Hz}$	The Facility remains connected to the Company System and in continuous operation.
$56.0\,\text{Hz} \leq f \leq 57.0\,\text{Hz}$	The Facility remains connected to the Company System and in continuous operation for at least six (6) seconds per event. The duration of the event is from the point at which the frequency is below 57 Hz and ends when the frequency is at or above 57 Hz. The Facility may initiate an alarm if frequency remains in this range for more than six (6) seconds.
$f < 56.0\,\text{Hz}$	The Facility remains connected to the Company System and in continuous operation for the duration allowed by the equipment operational limitations. The Facility may initiate an alarm immediately.

Protective Underfrequency Relaying (81U) shall be set to alarm only to meet the above ride-through requirements, and shall not initiate a disconnect from the Company System unless Seller reasonably determines based upon Good Engineering and Operating Practices that the Facility's equipment is at risk of damage. This is necessary in order to coordinate with the existing Company System.

Any tripping on calculated frequency should be based on accurately calculated and filtered frequency measurement over a time frame of minimum six cycles, or other period as specified by the Company, and should not use an instantaneously calculated value.

(j) Overfrequency Ride-Through. The Facility will behave as specified below for overfrequency conditions, and export of power shall continue with output adjusted as appropriate for Facility droop response consistent with **Section 1(g)(xi)** (Active Power – Frequency Response (DROOP)), **Section 1(g)(xii)** (Dynamic Active Power – Frequency Performance), and **Section 1(g)(xiii)** (Alternate Active Power / Frequency Response Modes) ("f" is the Company System frequency at the Point of Interconnection):

60.0 Hz $\leq$ f $\leq$ 61.5 Hz	The Facility remains connected to the Company System and in continuous operation.
61.5 Hz < f $\leq$ 63.0 Hz	The Facility remains connected to the Company System for at least ten (10) seconds. After ten seconds the Facility may initiate an alarm and the Facility remains connected and producing power for the duration allowed by the equipment operational limitations. The duration of condition is from the point at which the frequency is above 61.5 Hz and ends when the frequency is at or below 63.0 Hz.
f > 63.0 Hz	The Facility remains connected to the Company System for the duration allowed by the equipment operational limitations. The Facility may initiate an alarm immediately.

Protective Overfrequency Relaying (81O) shall be set to alarm only to meet the above ride-through requirements, and shall not initiate a disconnect from the Company System unless Seller reasonably determines based upon Good Engineering and Operating Practices that the Facility's equipment is at risk of damage. This is necessary in order to coordinate with the existing Company System.

Any tripping on calculated frequency should be based on accurately calculated and filtered frequency measurement over a time frame of minimum six cycles, or other period as specified by the Company, and should not use an instantaneously calculated value.

(k) **Successive Faults.** If the resource necessitates tripping to protect from the cumulative effects of those successive faults, in a period of time to ensure safety and equipment integrity, the constraint and time periods should be provided for inclusion in the interconnection study. For all cases, at a minimum, the ride-through requirements shall be met for two ride-through events within two seconds to allow for the Company's transmission automatic reclosing attempt[24].

(l) **Rate of Change of Frequency ("ROCOF").** The inverter-based resources in the Facility shall not use rate-of-change-of-frequency protection unless an equipment limitation exists that requires the inverter to trip on high ROCOF. Any ROCOF tripping must be approved by Company.

(m) **Phase Angle Shift Ride-Through.** The Facility equipment shall ride through phase angle shift of up to ([ ]) **[Note – requirements will depend on Facility].** Inverter phase lock loop (PLL) loss of synchronism shall not cause the inverter to trip or enter momentary cessation within the voltage and frequency ride-through region. Inverters must be capable of riding through temporary loss of synchronism, and regain synchronism, without causing a trip or momentary cessation of the resource.

(n) **DC Protection.** If the Facility requires DC reverse current protection, such protection must be coordinated with the inverter equipment module ratings and set to operate for short circuits on the DC side. DC reverse current protection shall not operate for transient overvoltage or for AC-side faults.

(o) **Voltage Flicker.** Any voltage flicker on the Company System caused by the Facility shall not exceed the limits stated in IEEE Standard 1453-2011, or latest version

"Recommended Practice – Adoption of IEC 61000-4-15:2010, Electromagnetic compatibility (EMC) – Testing and measurement techniques – Flickermeter – Functional and design specifications."

(p) **Harmonics.** Harmonic distortion at the Point of Interconnection caused by the Facility shall not exceed the limits stated in IEEE Standard 519-1992, or latest version "Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems." Seller shall be responsible for the installation of any necessary controls or hardware to limit the voltage and current harmonics generated from the Facility to defined levels.

(q) **Grid Forming Capabilities.** Seller Facility inverters shall be capable of operating in grid forming mode supporting system operation under normal and emergency conditions without relying on the characteristics of synchronous machines. This includes operation as a current independent ac voltage source during normal and transient conditions (as long as no limits are reached within the inverter) and the ability to synchronize to other voltage sources or operate autonomously if a grid reference is unavailable.

(i) Seller shall operate the Facility in grid forming mode only as directed by the Company System Operator, in its sole discretion. Such mode of operation shall be indicated to the Company System Operator through telemetry.

(ii) The Facility shall include safeguards to prevent the unintentional switching of the Facility into and out of grid forming mode. The safeguards shall be approved in writing by the Company and implemented by the Seller prior to control system testing.

(r) **Black Start Capability.** The BESS storage shall be capable of grid forming inverter capability so it can generate its own AC waveform rather than relying on a grid voltage to synchronize and maintain frequency. Further, inverter-based resources shall ensure they have sufficient energy storage to maintain power injection to the grid during system restoration (i.e., have power available when and if called upon). Inverter based facilities should be capable of support as a black start cranking path to start synchronous generators for restoration.

(s) Provision of Synthetic Inertia.

(t) Generator Step-Up Transformer Impedance. The generator step-up transformer impedance shall be between [ ] percent and [ ] percent, inclusive, on transformer OA rating.

(u) Control Systems and Auxiliary Equipment. The power source for control systems and auxiliary equipment required for normal operation of the Facility shall be designed to be immune from system transients in accordance with the Public Utilities Commission of the State of Hawaii tariff for Maui Electric Company, Ltd. Rule No. 2, Character of Service (Revised Sheet No. 5, effective Oct. 20, 1991) and Section 3.2(A)(6) (Facility Protection and Control Equipment) to meet the performance during under/over voltage and under/over frequency conditions pursuant to **Section 3(e)** (Undervoltage Ride-Through), **Section 3(f)** (Over Voltage Ride-Through), **Section 3(i)** (Underfrequency Ride-Through) and **Section 3(j)** (Overfrequency Ride-Through) of this **Attachment B** (Facility Owned by Seller).

(v) Frequency Response. Seller shall comply with the requirements of **Section 1(g)(xi)** (Frequency Response (DROOP)), **Section 1(g)(xii)** (Dynamic Active Power – Frequency Performance), and **Section 1(g)(xiii)** (Alternate Active Power / Frequency Response Modes) of this **Attachment B** (Facility Owned by Seller).

(w) Round Trip Efficiency. The round trip efficiency of the BESS as measured at the Point of Interconnection shall be not less than 83 percent (83%).

<u>8(v) Data</u> Collection.

A. High Resolution Data: Seller shall install and make available to the Company time stamped and sequential data recordings for all inverter-based resources (and all generating resources) to perform event analysis and verify Facility performance during steady state and transient disturbance events. This will include a time-synchronized phasor measurement unit at the Facility, and access to multiple sources to provide sufficient clarity as to any abnormal response or behavior within the Facility, including Facility control settings and static values, SCADA data, sequence of events recording (SER) data, dynamic disturbance recorder (DDR) data, and inverter fault codes and inverter-level dynamic recordings. This data will be used to review the Facility's response to system dynamics, such as the frequency response (normal droop and FFR), reactive response, etc.

B. Plant Data: Seller shall install at least three (3) meteorological tower(s), spaced so as to provide the data points set forth below for the entire Facility. At least two months prior to the Commercial Operation Date, Seller shall deliver to Company a report showing (i) manufacturer, model and year of all energy equipment (inverters, energy storage devices), and meteorological instrumentation, and (ii) the latitude and longitude of the center of the energy equipment (i.e., solar panels for every inverter, wind turbines) and every meteorological tower. Beginning upon COD, Seller shall transmit and provide to Company the real-time data set forth below, refreshed as frequently as allowed by the SCADA system, not to exceed sixty (60) second intervals:

- Three (3) data points from each inverter:
    - Inverter generation (MW)
    - Inverter availability

- Inverter on/offline status

Seller shall provide a map and key for each inverter sufficient to allow Company to correlate the data received through Company's data historian system to each individual resource.

ATTACHMENT G

COMPANY-OWNED INTERCONNECTION FACILITIES

1(f). Review of the Listing and Costs. If the Commercial Operations Date is not achieved by the Guaranteed Commercial Operations Date, as such date may be extended as provided in **11.4** (Milestone Dates), the listing of the Company-Owned Interconnection Facilities required in this Agreement and the cost-estimates for such Company-Owned Interconnection Facilities are subject to review and revision. Such revision may include, but not be limited to, such items as reconductoring an existing transmission or distribution line, construction of a new line, increase transformer capacity, and alternative relay specifications. In addition, such review and revision may require that the Company re-perform or update the IRS at Seller's expense.

2(f) Acceptance Test Procedures.

(i) Seller acknowledges that: (aa) Company has multiple on-going projects with other developers as well as its own capital improvement projects and on-going system work; (bb) Company has limited resources to provide engineering oversight (such as review of plans) to such projects and to participate in the testing of such projects; (cc) in order for Company to accommodate such oversight and testing, it is necessary for Company to sequentially allocate its resources for each project a year or more in advance; (dd) the result is a queue of such projects that reflects the scheduling commitments of Company's resources to conduct such oversight and to participate in such testing; (ee) if a project is behind the schedule on which Company's resources have been scheduled for the oversight of such project, or if a project is not ready for testing at the time Company's resources have been scheduled for the testing of such project, or if a project does not complete testing within the period for which Company's resources have been scheduled for such testing, the progress of projects later in the queue may be adversely affected; (ff) the Test Ready Deadline that is set forth in **Attachment K-1** (Seller's Conditions Precedent and Company Milestones) reflects the scheduling commitment of Company's resources to (i) conduct the oversight necessary to facilitate Seller's achievement of that Test Ready Deadline, (ii) commence the Acceptance Test on the Acceptance Testing Milestone Date that is set forth in **Attachment K-1** (Seller's Conditions Precedent and Company Milestones) and (iii) thereafter participate in the Control System Acceptance Test; and (gg) in the Company's sole discretion based on its assessment of Company's resources and overall schedule of projects at the time, the Project may lose its place in the queue and may be assigned a new Acceptance Testing Milestone Date for commencement of the Acceptance Test that may be behind the other projects then in the queue if (i) Seller fails to satisfy any of the conditions precedent set forth in **Section 2(f)(ii)** of this **Attachment G** (Company-Owned Interconnection Facilities) within the time period specified therein for the task in question or, if no time period is specified therein, by the Test Ready Deadline, (ii) the Seller fails to satisfy any of the Seller's Conditions Precedent set forth in **Attachment K-1** (Seller's Conditions Precedent and **Company** Milestones) and/or (iii) the Acceptance Test and the Control System Acceptance Test are not satisfactorily completed within the time allotted to complete such testing.

(ii) The Conduct of the Acceptance Test is subject to the satisfaction of the following conditions precedent within the time period specified below for the task in question or, if no time period is specified, by the Test Ready Deadline that is set forth in **Attachment K-1** (Seller's Conditions Precedent and Company Milestones):

(A) Final Single-Line Drawing, and notes, has received Company's written consent pursuant to **Section 1(a)(i)** (Single-Line Drawing, Interface Block Diagram, Relay List, Relay Settings and Trip Scheme) of **Attachment B** (Facility Owned by Seller) to this Agreement.

(B) Final Relay List and Trip Scheme have received Company's written consent pursuant to **Section 1(a)(i)** (Single-Line Drawing, Interface Block Diagram, Relay List, Relay Settings and Trip Scheme) of **Attachment B** (Facility Owned by Seller) to this Agreement.

(C) Final Interface Block Diagram has received Company consent pursuant to **Section 1(a)(i)** (Single-Line Drawing, Interface Block Diagram, Relay List, Relay Settings and Trip Scheme) of **Attachment B** (Facility Owned by Seller) to this Agreement.

(D) Final Control System Telemetry and Control List has received Company consent.

(E) Final digital fault recorder settings, if applicable, have received Company consent.

(F) Control system design and tunable parameters reviewed and mutually agreed upon as needed to meet the Company requirements in accordance with **Section 3** (Performance Standards) of **Attachment B** (Facility Owned by Seller) to this Agreement.

(G) Agreement on Active Power Control Interface.

(H) No later than fourteen (14) Days prior to commencement of the Acceptance Test:

(1) Seller shall have certified to Company that Seller-Owned Interconnection Facilities have been installed and commissioned and such certification has not, prior to the commencement of the Acceptance Test, been subsequently challenged by Company on the basis of onsite observations made by the Company's representatives following the walk-through to be conducted pursuant to **Section 2(f)(iii)** of this **Attachment G** (Company-Owned Interconnection Facilities).

(2) Seller shall have certified to Company that any Company-Owned Interconnection Facilities built by Seller (and/or its Contractors) have been installed and commissioned and such certification has not, prior to the commencement of the Acceptance Test, been subsequently challenged by Company on the basis of onsite observations made by the Company's representatives following the walk-through to be conducted pursuant to **Section 2(f)(iii)** of this **Attachment G** (Company-Owned Interconnection Facilities).

(I) Any Company-Owned Interconnection Facilities not built by or on behalf of Seller have been installed and commissioned.

(J) No later than seven (7) Days prior to the commencement of the Acceptance Test, Seller and Company shall have participated in walk-through of fully constructed Interconnection Facilities.

(K) Redlined as-built drawings of the Seller-Owned Interconnection Facilities and any of the Company-Owned Interconnection Facilities built by Seller (and/or its Contractors) shall have been provided to Company.

(L) Continuous power is being supplied to Company's protection and SCADA equipment.

(M) Not less than four (4) weeks prior to the commencement of the Acceptance Test, the high speed communication lines required under this Agreement have been commissioned and are ready for use for EMS and revenue metering purposes.

(N) Not less than two (2) weeks prior to the commencement of the Acceptance Test, Seller and Company have participated in an on-Site Acceptance Test coordination meeting.

(iii) Seller shall provide Company with at least fourteen (14) Days advance written notice of the Acceptance Test, which shall be scheduled during normal business hours on a Business Day (and may take a minimum of thirty (30) Days to complete). No electric energy will be delivered from Seller to Company during this Acceptance Test. No later than thirty (30) Days prior to conducting the Acceptance Test, Company and Seller shall agree on a written protocol setting out the detailed procedure and criteria for passing the Acceptance Test. **Attachment N** (Acceptance Test General Criteria) provides general criteria to be included in the written protocol for the Acceptance Test. At the time that Seller provides its 14-Day notice of the Acceptance Test to Company, Seller shall concurrently schedule a site walk-through of the Facility with Company to occur no later than seven (7) Days prior to the Acceptance Test. Seller's 14-Day notice to Company of the Acceptance Test shall constitute its certification that (A) the installation and commissioning of the Seller-Owned Interconnection Facilities and the Company-Owned Interconnection Facilities built by Seller (and/or its Contractors) has been completed; and (B) a walk-through by Company shall demonstrate, to Company's reasonable satisfaction, Seller's readiness to commence with the Acceptance Test. If, after the site walk-through, Company representatives reasonably determine that Seller is not ready to commence with the Acceptance Test, the Project will lose its place in the queue and will be assigned a new Test Ready Deadline and a new Acceptance Testing Milestone Date. In the meantime, Seller shall remediate the deficiencies identified by Company, and the process described in this **Section 1(f)** (Acceptance Test Procedures) of **Attachment G** (Company-Owned Interconnection

Facilities), shall commence again until Seller's readiness for the Acceptance Test is demonstrated to Company's reasonable satisfaction. Successful completion of the Acceptance Test requires successful completion of each of the individual tests that comprise the Acceptance Test. Retesting of any individual test constitutes as restart of the Acceptance Test if such retesting is required because of a prior failure of such individual test or because a prior test could not be completed because of a problem with the Facility. Within fifteen (15) Business Days of successful completion of the Acceptance Test and Company's receipt of the final report setting forth the results of the Acceptance Test, Company shall notify Seller in writing whether the Acceptance Test has been passed and, if so, the date upon which the Acceptance Test was passed.

ATTACHMENT K

GUARANTEED PROJECT MILESTONES

Guaranteed Project Milestone Date	Description of Each Guaranteed Project Milestone
N/A	Construction Financing Milestone: Seller shall provide Company with documentation reasonably satisfactory to Company evidencing (a) the closing on financing for the Facility including ability to draw on funds by **[insert same date certain as in left column]** or (b) the financial capability to construct the Facility**Error! Bookmark not defined.**
N/A	Permit Application Filing Milestone: Seller shall provide Company with documentation reasonably satisfactory to Company evidencing the filing by or on behalf of Seller of the following applications for Governmental Approvals required for the ownership, construction, operation and maintenance of the Facility:
11/30/21	**State of Hawaiʻi Department of Land & Natural Resources, SHPD** * HRS Chapter 6E: Historic Preservation **County of Maui Department of Public Works, Development Services Administration Division** * Chapter 20.08: Soil Erosion and Sedimentation Control; Grading Control * Chapter 20.08: Soil Erosion and Sedimentation Control; Grubbing Permit * Building Permit **State of Hawaiʻi Department of Health, Clean Water Branch** * NPDES Construction Stormwater Permit
4/28/2023	Guaranteed Commercial Operations Date

ATTACHMENT K-1

SELLER'S CONDITIONS PRECEDENT AND COMPANY MILESTONES

Seller's Conditions Precedent Date	**Description of Each of Seller's Conditions Precedent**
N/A	Seller shall make payment to Company of the amount required under **Section 3(b)(ii)** of **Attachment G** (Company-Owned Interconnection Facilities)**Error! Bookmark not defined.**
N/A	Seller shall provide Company a right of entry for the Company-Owned Interconnection Facilities site(s).
N/A	Seller shall make payment to Company of the amount required under **Section 3(b)(iii)** of **Attachment G** (Company-Owned Interconnection Facilities)**Error! Bookmark not defined.**
2/28/22	Seller's EPC Contractor shall obtain grading permit.
N/A	Seller's EPC Contractor shall obtain and provide Company all permits (other than any required occupancy permits, if applicable), licenses, easements and approvals to construct the Company-Owned Interconnection Facilities, including the building permit.
No later than three (3) months prior to commencement of the Acceptance Test	Seller shall provide station service power, if applicable, as required by Company.
No later than three (3) months prior to the commencement of the Acceptance Test	Seller or Seller's EPC Contractor shall have Hawaiian Telcom Backup (or equivalent) installed which shall consist of a 1.5 Mbps Routed Network Services circuit for backup SCADA communications from Company's Substation at Seller's Facility to Company's EMS located at the Company's control center.
8/30/2022	Seller's EPC Contractor shall complete installation of physical bus and structures within Company's substation up to the demark point as necessary to interconnect.

1/31/2023 ("Test Ready Deadline")	Seller's EPC Contractor shall complete construction of the Seller-Owned Interconnection Facilities, Seller shall have satisfied the conditions precedent to the conduct of the Acceptance Test set forth in **Section 2(f)(ii)** of **Attachment G** (Company-Owned Interconnection Facilities) and Seller is otherwise ready to conduct the Acceptance Test.
8/1/2022	Seller shall close grading permit, unless Seller provides documentation establishing, to Company's reasonable satisfaction, that closing the grading permit is not required by the relevant Governmental Authority prior to energization, testing and use of the Facility.

<u>COMPANY MILESTONES</u>

If Seller satisfies the foregoing Seller's Conditions Precedent, the following Company Milestones shall apply:

Company Milestone Date	**Description of Each Company Milestone**
2 Business Days following the Test Ready Deadline	Company shall, subject to Seller's continued satisfaction of the requirements set forth in **Section 2(f)(ii)** and **Section 2(f)(iii)** of **Attachment G** (Company-Owned Interconnection Facilities), commence Acceptance Testing.
12/30/22	Energization of Company-Owned Interconnection Facilities, provision of back-feed power to support commissioning.

ATTACHMENT L
REPORTING MILESTONES

Reporting Milestone Date	Description of Each Reporting Milestone
3/31/2021	Seller shall provide Company with a redacted copy of the executed Facility equipment, engineering, procurement and construction, or other general contractor agreements; provided, that, under no circumstances shall redactions conceal information that is necessary for Company to verify its rights under the Agreement
11/30/2021	Seller shall provide Company with redacted copies of executed purchase orders/contracts for the delivery and installation of Facility inverters
N/A	Seller shall provide Company with copies, as applicable, of executed Facility operating agreements
3/31/2022	Construction Start Date (defined as the start of civil work on Site)
8/31/2022	Seller shall have laid the foundation for all Facility buildings and step-up transformer facilities
10/30/2022	All inverters for the Facility shall have been installed at the Site
10/30/2022	The step-up transformer shall have been installed at the Site

ATTACHMENT N

ACCEPTANCE TEST GENERAL CRITERIA[29]

Upon final completion of Company review of the Facility's drawings, final test criteria and procedures shall be agreed upon by Company and Seller no later than thirty (30) Days prior to conducting the Acceptance Test in accordance with the Agreement. The Acceptance Test shall include, but not be limited to, the following:

1. Interconnection.

(a) A visual inspection of all Interconnection equipment and verification of as-built drawings.

(b) Phase rotation testing to verify proper phase connections.

(c) Based on manufacturer's specification, test the local operation of the Facility's generator breaker(s) and inter-tie breaker(s), and other breaker(s) which connect the Facility equipment to Company System – must open and close locally using the local controls remotely from Company's EMS. Test and ensure that the status shown on the EMS is the same as the actual physical status in the field.

(d) Relay test engineers to connect equipment and simulate certain inputs to test and ensure that the protection schemes such as any under/over frequency and under/over voltage protection or the Direct Transfer Trip operate as designed. (For example, a fault condition may be simulated to confirm that the breaker opens to sufficiently clear the fault. Additional scenarios may be tested and would be outlined in the final test criteria and procedures.) Seller to also test the synchronizing mechanisms to which the Facility would be synchronizing and closing into the Company System to ensure correct operation. Other relaying also to be tested as

[29] Data and test points will not be available until the completion of the Interconnection Requirements Study ("IRS").

specified in the protection review of the IRS and on the single line diagram, **Attachment E** (Single-Line Drawing and Interface Block Diagram) for the Facility.

(e) All 69 kV breaker disconnects and other high voltage switches will be inspected to ensure they are properly aligned and operated manually or automatically (if designed).

(f) Step-Up Transformer Enclosure(s) inspections – The Step-Up Transformer Enclosure(s) may be inspected to test and ensure that the equipment that Seller has installed is installed and operating correctly based upon agreed to design. Wiring may be field verified on a sample basis against the wiring diagrams to ensure that the installed equipment is wired properly. The grounding mat at the Step-Up Transformer Enclosure(s) may be tested to make sure there is adequate grounding of equipment.

(g) Communication testing – Communication System testing to occur to ensure correct operation. Detailed scope of testing will be agreed by Company and Seller to reflect installed systems and communication paths that tie the Facility to Company's communications system.

(h) Various contingency scenarios to be tested to ensure adequate operation, including testing contingencies such as loss of communications, and fault simulations to ensure that the Facility's 69 kV breakers, if any, open as they are designed to open. (Back up relay testing)

(i) Metering section inspection; verification of metering PTs, CTs, and cabinet and the installation of the two Company meters.

2. Telephone Communication.

(a) Test to confirm Company has a direct line to the Facility control room at all times and that it is programmed correctly.

(b) Test to confirm that the Facility operators can sufficiently reach Company System Operator.

(c) Verification of dial-up telephone connection for 69 kV metering cabinet.

3. Drawings, Documentation and Equipment Warranties.

The items below are required components of the Acceptance Test and must be satisfied for successful completion of this Test.

(a) Electronic and three (3) hard copies of all Switchyard construction drawings, specifications, calibrations, and settings including as-built drawings.

(b) Equipment operating and maintenance manuals, spare parts lists, commissioning notes, as-built equipment settings, and other information related to the switchyard equipment.

(c) Contractor construction warranties and equipment warranties.

(d) Phase rotation testing to verify proper phase connections.

(e) Switching Station inspections – The Switching Station may be inspected to test and ensure that the equipment that Seller has installed is installed and operating correctly based upon agreed-to design. Wiring may be field verified on a sample basis against the wiring diagrams to ensure that the installed equipment is wired properly. The grounding mat at the Switching Station may be tested to make sure there is adequate grounding of equipment.

(f) If agreed by the Parties in writing, some requirements may be postponed to the Control Systems Acceptance Test.

ATTACHMENT O[30]

CONTROL SYSTEM ACCEPTANCE TEST CRITERIA

Final test criteria and procedures shall be agreed upon by Company and Seller no later than thirty (30) Days prior to conducting the Control System Acceptance Test in accordance with Good Engineering and Operating Practices and with the terms of this Agreement. The Control System Telemetry and Control List is necessary for the effective operation of the Company System and will be tested during the Control System Acceptance Test.

The Control System Acceptance Test is comprised of two parts, a set of onsite (at Facility) specific tests and a monitoring performance test. These tests may include the following:

On-site Tests (Between Facility and Company Dispatch Center):

1. SCADA Test to verify the status and analog telemetry, and if the remote controls between the Company's EMS and the Facility are working properly end-to-end.

2. Meter Test to verify the status and analog telemetry between Company's revenue meter data acquisition system and the Facility's revenue meters are working properly end-to-end.

3. Dispatch Test to verify if the Facility's active power controls and the Active Power Control Interface with the Company's EMS are working properly. This test is generally conducted by setting different active power setpoints and limits and observing the proper dispatch of the appropriate ramp rate of the Facility's real power output.

4. Control Test for Voltage Regulation to verify the Facility can properly perform automatic voltage regulation as defined in this Agreement. This test is generally conducted by

[30] Data and test points will not be available until the completion of the Interconnection Requirements Study ("IRS")

making small adjustments of the voltage setpoint and verifying by observation that the Facility regulates the voltage at the point of regulation to the setpoint by delivering/receiving reactive power to/from the Company System to maintain the applicable setpoint according to the reactive power control and the reactive amount requirements of **Section 3** (Performance Standards) of **Attachment B** (Facility Owned by Seller) to this Agreement.

5. Frequency Regulation Control Test to verify the Facility provides a frequency droop response as defined in this Agreement. This test is generally conducted by making adjustments of the frequency reference setting and verifying by observation that the Facility responds per droop and deadband settings.

6. Test other controls defined in this Agreement or mutually agreed upon in writing by the Parties to enable, disable, dispatch and/or schedule the energy storage system real power and energy operations.

7. Loss-of-Communication Test to verify the Facility will properly shutdown upon the failure of the direct-transfer-trip communication system. This test is generally conducted by simulating a communications failure and observing the proper shutdown of the Facility.

8. Round Trip Efficiency Test, as described in **Attachment T** (Facility Tests) to verify that the round trip efficiency of the BESS is not less than 83 percent ([83]%).

9. Capacity Test to verify the Capacity Ratio.

Monitoring Test:

(a) The monitoring test requires the Facility to operate as it would in normal operations.

(b) To ensure useful and valid test data is collected, the monitoring test shall end seven (7) continuous Days from the start of the Monitoring Test.

(c) The performance of the Facility during the period of a successfully completed monitoring test is evaluated for, e.g., voltage regulation, frequency response, dispatch control, operating limits and ramp rate performance, to verify the performance meets the requirements of this Agreement.

ATTACHMENT T

FACILITY TESTS[31]

Prior to achieving Commercial Operations and in each Measurement Period, unless waived by Company, Seller shall demonstrate that the Facility satisfies the following:

Maintains output provided by the Company through a control setpoint, as measured at the Point of Interconnection, and is able to continuously dispatch the full Contract Capacity (the "**Capacity Test**")

Demonstrates the charging/discharging requisite to satisfy the performance standard set forth in **Section 3(w)** (Round Trip Efficiency) of **Attachment B** (Facility Owned by Seller) (the "**RTE Test**")

The RTE Test requires measurement of "Charging Energy" at the Point of Interconnection (MWh from the grid) from Facility 0% State of Charge to bring the Facility to a 100% State of Charge, followed by measurement of the MWh delivered to the grid to bring the Facility to a 0% State of Charge. The RTE Test will be conducted concurrently with the Capacity Test.

The Capacity Test can only be performed when the Facility is at the lower of: (i) its maximum State of Charge or (ii) 100% State of Charge prior to the start of the Capacity Test and during the Capacity Test the Company Dispatch/Charge allows for continuous dispatch of the Facility to 0% State of Charge with energy delivered to the Point of Interconnection.

For the purposes of evaluating the Capacity Test, the "**Capacity Ratio**" shall be equal to the number, expressed as a percentage, equal to the total MWh delivered to the Point of Interconnection during the Capacity Test, divided by the Contract Capacity. Further, the

[31] Data and test points will not be available until the completion of the Interconnection Requirements Study ("IRS")

Capacity Test will be deemed to be "passed" or "satisfied" to the extent the Capacity Ratio is not less than **100%** (the "**Capacity Performance Metric**").

For the purposes of evaluating the RTE Test, the RTE Ratio shall be equal to the number, expressed as a percentage, equal to the total MWh delivered to the Point of Interconnection during the Capacity Test, divided by the "Charging Energy" measured at the Point of Interconnection. For purposes of the RTE Test, the charging cycle shall begin when the Facility is at a 0% State of Charge prior to the commencement of the Capacity Test and the Charging Energy is the amount of energy imported from the grid, as measured at the Point of Interconnection, that brings the Facility to a 100% State of Charge. The formula is RTE Ratio = MWh discharge ÷ MWh charge. The RTE Test will be deemed to have been "passed" or "satisfied" to the extent the RTE Ratio is not less than the performance standard (the "**RTE Performance Metric**") set forth in **Section 3(w)** (Round Trip Efficiency) of **Attachment B** (Facility Owned by Seller).

Except for the Capacity Test conducted prior to Commercial Operations, Seller shall, in lieu of conducting a Capacity Test, be permitted to demonstrate satisfaction of the Capacity Performance Metric by reference to the operational data reflecting the net output of the Facility from the Point of Interconnection for such Measurement Period.

Except for the RTE Test conducted prior to Commercial Operations, Seller shall, in lieu of conducting an RTE Test, be permitted to demonstrate satisfaction of the RTE Performance Metric by reference to the operational data reflecting the charging/discharging of the Facility from the Point of Interconnection during such Measurement Period.

Any Capacity Test or RTE Test (each a "**Facility Test**" and collectively, the "**Facility Tests**"), other than where the Capacity Performance Metric or RTE Performance Metric, as applicable, is demonstrated by reference to operational data as provided below, shall be performed at a time reasonably requested by the Company in its sole discretion. Within a Measurement Period, Seller shall be permitted up to a total of three (3) Facility Tests to demonstrate satisfaction of the Capacity Performance Metric and the RTE Performance Metric for such Measurement Period, unless additional such tests are authorized by Company. Company shall provide notice to Seller no less than three (3) Business Days prior to conducting a Facility Test.

At any time prior to conducting the third (3^{rd}) Capacity Test noticed by Company for a Measurement Period, Seller may demonstrate satisfaction of the Capacity Performance Metric by reference to operational data reflecting the net output of the Facility from the Point of Interconnection for such Measurement Period. If, during a Measurement Period, Seller both fails to pass a Capacity Test noticed by Company and fails to demonstrate satisfaction of the Capacity Performance Metric by reference to operational data for such Measurement Period, the Facility shall nevertheless be deemed to have satisfied the Capacity Performance Metric for the applicable Measurement Period if either (i) Company failed to notice at least three (3) Capacity Tests during such Measurement Period, or (ii) Seller was unable to perform at least two (2) such noticed Capacity Tests during such Measurement Period due to (a) conditions on the Company System other than Seller-Attributable Unavailability or (b) an act or omission by Company.

At any time prior to conducting the third RTE Test noticed by Company for a Measurement Period, Seller may demonstrate satisfaction of the RTE Performance Metric by reference to operational data reflecting charging/discharging of the Facility from the Point of Interconnection during such Measurement Period. If, during a Measurement Period, Seller both fails to pass a RTE Test noticed by Company and fails to demonstrate satisfaction of the RTE

Performance Metric by reference to operational data for such Measurement Period, the Facility shall nevertheless be deemed to have satisfied the RTE Performance Metric for the applicable Measurement Period if either (i) Company failed to notice at least three RTE Tests during such Measurement Period, or (ii) Seller was unable to perform at least two (2) such noticed RTE Tests during such Measurement Period due to (a) conditions on the Company System other than Seller-Attributable Unavailability or (b) an act or omission by Company.

Company shall have the right to attend, observe and receive the results of all Facility Tests. Seller shall provide to Company the results of each Facility Test (including time stamped graphs of system performance based in operational data or test data) no later than ten (10) Business Days after the performance of such Facility Test.

ATTACHMENT V
ANNUAL EQUIVALENT FORCED OUTAGE FACTOR

$$EFOF = 100\% \times \frac{(FOH + EUDH)}{8760}$$

Where:

EUDH is the equivalent unplanned (forced) derated hours. Each Unplanned (Forced) Derating of the Facility is transformed into equivalent full outage hour(s). This is calculated by multiplying the actual duration of the Deration (hours) by (i) the size of the reduction (MW) divided by (ii) the Maximum Rated Output. These equivalent hour(s) are then summed for the Measurement Period and added to the sum of the EUDH for the immediately preceding three (3) full Measurement Periods.

- (Hours of Deration x Size of Reduction) ÷ Maximum Rated Output

Forced Outage Hours (FOH) = Sum of all hours experienced during Unplanned (Forced) Outages during the applicable Measurement Period and the sum of all hours experienced during Unplanned (Forced) Outages during the immediately preceding three (3) full Measurement Periods, in each case caused by Seller-Attributable Unavailability.

Unplanned (Forced) Derating: A Deration that requires a reduction in capacity of the Facility before the end of the nearest following weekend.

Unplanned (Forced) Outage: An outage that requires removal of the entire Facility from service before the end of the nearest following weekend that is not planned.

EXAMPLE CALCULATION:

Assume a 50 MW Facility that for the Measurement Period in question was completely out of service for 50 hours. For the Measurement Period in question, it also had the following deratings:

Duration of Derating	MW Size Reduction
100 Hours	25 MW
20 Hours	20 MW
50 Hours	5 MW

During the three preceding Measurement Periods, the Facility had a total of 150 Forced Outage Hours and a total of 100 Equivalent Forced Derated Hours.

FOH = 50 hours + 150 hours = 200 hours
EUDH = [(100 x 25) ÷ 50] + [(20 x 20) ÷ 50] + [(50 x 5) ÷ 50] + 100 = 163 hours

$$EFOF = 100\% \times \frac{(200 + 163)}{8760} = 4.1\%$$

EXHIBIT 2: WAENA BESS PROJECT COST SUMMARY

COST SUMMARY

Table 1 below shows a high-level summary of the total cost estimate for the 40 MW 4-hour Battery Energy Storage System (BESS) project. Because this project was selected under a competitive bidding process, all cost breakdowns provided below are considered to be confidential information so as to protect the Company's competitive position.:

Table 1 – BESS Project Total Cost Estimate

Item	Cost ($000s)
1. EPC Contractor	[redacted]
2. Substation Interconnection	
3. Owner's Cost	
4. 69 kV Interconnection	
5. AFUDC	
6. Overheads	
Total Cost	

The following sections provide brief explanations for line items 1 through 6 in Table 1, above.

BATTERY ENGINEERING, PROCUREMENT, and CONSTRUCTION ("EPC") CONTRACT

The cost for the battery system EPC is from Tesla, who was selected based on a competitive bidding process conducted by the self-build team. The line items shown as "Covered in EPC" are major items that have been confirmed with Tesla to be included in the proposal.

Table 2 – EPC Contract Pricing

Item	Cost ($000s)
[redacted]	

[redacted]

OWNER'S COSTS

The breakdown of labor and non-labor cost direct to Hawaiian Electric for the project is shown below**Error! Not a valid bookmark self-reference.**. Support of a full-time project manager is included in the costs. A contracted "owner's representative" will be onsite during the construction phase of the project. Engineering support will be needed from electrical, mechanical, structural, controls, and telecom engineering disciplines within the Company.

Table 3: Owner's Cost Breakdown

Item	**Cost ($000s)**
OS Owner's Representative	[redacted]
Project Management Labor	
Engineering Labor	
Total Owner's Cost	

INTERCONNECTION COSTS

Table below shows the estimate for the interconnection of the BESS to the Waena Switchyard at the 69 kV level. This work is anticipated to be performed by Hawaiian Electric crews or contractors directly retained by Hawaiian Electric.

Table 4: 69 kV Waena Switchyard Interconnection Costs

Item	**Cost ($000s)**
Substation Materials/Construction for Interconnection	[redacted]
T&D Materials/Construction for Interconnection	
Total Interconnection Cost	

OVERHEAD

The overhead costs for the Waena BESS Project were obtained using Hawaiian Electric's budgeting software (UI Planner) and represent an allocation for those Company costs that are not attributable to any particular project or operation, but are essential, nonetheless. The total estimated amount of overheads represents approximately [redacted]% of total project costs. Overheads are comprised of non-productive wages (such as holiday, sick, and vacation pay), employee benefits, payroll taxes, corporate administrative costs, and clearing costs.

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION

The Allowance for Funds Used During Construction ("AFUDC") for the Project was obtained using Hawaiian Electric's budgeting software (UI Planner). The total amount of estimated AFUDC is [redacted] which represents [redacted]% of the total budget.

OPERATIONS AND MAINTENANCE COSTS (O&M)

The Megapacks, inverters, and Megapack Controllers have detailed preventative maintenance scheduled. Several system inspections, checks, and cleanings are required on an annual basis with small replacements at 5 and 10 years. The MV transformers, switchgear, and GSU also require periodic maintenance. Annual site operational costs and other expenses & fees have also been budgeted for. Annual O&M costs are provided in Exhibit 5.

The most significant annual O&M cost is the BESS maintenance contract with Tesla. The contract includes a capacity maintenance agreement ("CMA") which will provide for not only maintenance of the BESS throughout its life, but also for the unit replacements and augmentation necessary to maintain the performance and capacity of the BESS at rated levels through the life of the Project. CMA costs are detailed in Exhibit 5.

Confidential Information Deleted
Pursuant To Protective Order No. ________

SCHEDULE B1
(To file by May 2023 for Yr 1)
(To file by Feb 2024 for Yr 2)
PAGE 1 OF 1

The purpose of this Schedule B1 is to illustrate how the Waena BESS project will flow through the MPIR mechanism into Target Revenue. All other numbers are from Transmittal No 20-03 Consolidated (Decoupling) filing filed on June 5, 2020 and will change

MAUI ELECTRIC COMPANY, LIMITED
DECOUPLING CALCULATION WORKBOOK
DETERMINATION OF TARGET REVENUES

Line No.	Description	Reference		Docket No. 2017-0150 Amounts	Docket No. 2017-0150 Amounts	Docket No. 2017-0150 Amounts	Docket No. 2017-0150 Amounts	Docket No. 2017-0150 Amounts	Note (4) MPIR ILLUSTRATIVE EFFECTIVE 5/1/2023	Note (5) MPIR ILLUSTRATIVE EFFECTIVE 1/1/2024
	(a)	(b)		(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Last Rate Case Annual Electric Revenue at Approved Rate Levels	Note 1	$000s	$ 336,045	$ 335,763	$ 335,763	$ 335,763	$ 335,763	$ 335,763	$ 335,763
2	Less Fuel Expense	Note 1	$000s	$ (103,385)	$ (103,385)	$ (103,385)	$ (103,385)	$ (103,385)	$ (103,385)	$ (103,385)
3	Purchased Power Expense	Note 1	$000s	$ (54,970)	$ (54,970)	$ (54,970)	$ (54,970)	$ (54,970)	$ (54,970)	$ (54,970)
4	Revenue Taxes on Line 1 (8.885% statutory rates)		$000s	$ (29,858)	$ (29,833)	$ (29,833)	$ (29,833)	$ (29,833)	$ (29,833)	$ (29,833)
5	Last Rate Order Target Annual Revenues	Sum Lines 1 thru 4	$000s	$ 147,832	$ 147,575	$ 147,575	$ 147,575	$ 147,575	$ 147,575	$ 147,575
6	Authorized RAM Revenues - Transmittal No. 19-03	Sch. A, line 4	$000s	$ -	$ 2,694	$ 2,694	$ -	$ -	$ -	$ -
7	Less Revenue Taxes on Line 6 at 8.885%		$000s	$ -	$ (239)	$ (239)	$ -	$ -	$ -	$ -
8	Net RAM Adjustment - Test Year	Lines 6 + 7	$000s	$ -	$ 2,455	$ 2,455	$ -	$ -	$ -	$ -
9	Authorized RAM Revenues - Transmittal No. 20-03	Sch. A, line 5	$000s	$ -	$ -	$ -	$ 8,411	$ 8,411	$ 8,411	$ 8,411
10	Less Revenue Taxes on Line 9 at 8.885%		$000s	$ -	$ -	$ -	$ (747)	$ (747)	$ (747)	$ (747)
11	Net RAM Adjustment - Test Year	Lines 9 + 10	$000s	$ -	$ -	$ -	$ 7,664	$ 7,664	$ 7,664	$ 7,664
12	Authorized MPIR Revenues	Schedule L/La Note 3	$000s	$ -	$ -	$ 57	$ 57	$ 57	[redacted]	
13	Less Revenue Taxes on Line 12 at 8.885%		$000s	$ -	$ -	$ (5)	$ (5)	$ (5)		
14	Net MPIR Adjustment	Lines 12 + 13	$000s	$ -	$ -	$ 52	$ 52	$ 52		
15	Less EARNINGS SHARING REVENUE CREDITS	Note 3	$000s	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16	Less Revenue Taxes on Line 15 at 8.885%		$000s	$ -	$ -	$ -	$ -	$ -	$ -	$ -
17	Net Earnings Sharing Revenue Credits	Lines 15 + 16	$000s	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	Less PERFORMANCE INCENTIVE MECHANISM REWARD (PENALTY)	Note 3	$000s	$ -	$ (395)	$ (395)	$ (501)	$ (501)	$ (501)	$ (501)
19	Less Revenue Taxes on Line 18 at 8.885%		$000s	$ -	$ 35	$ 35	$ 45	$ 45	$ 45	$ 45
20	Net Performance Incentive Mechanism	Lines 18 + 19	$000s	$ -	$ (360)	$ (360)	$ (456)	$ (456)	$ (456)	$ (456)
21	Less 2017 Tax Reform Act Adjustment (1/1/18-5/31/18)	Note 3	$000s	$ (2,769)	$ -	$ -	$ -	$ -	$ -	$ -
22	Less Revenue Taxes on Line 21 at 8.885%		$000s	$ 246	$ -	$ -	$ -	$ -	$ -	$ -
23	Net 2017 Tax Reform Act Adjustment	Lines 21 + 22	$000s	$ (2,523)	$ -	$ -	$ -	$ -	$ -	$ -
24	Add OBF Program Implementation Costs	Note 3	$000s	$ -	$ 198	$ 198	$ 203	$ 203	$ 203	$ 203
25	Less Revenue Taxes on Line 24 at 8.885%		$000s	$ -	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)
26	Net OBF Program Implementation Costs	Lines 24 + 25	$000s	$ -	$ 181	$ 181	$ 185	$ 185	$ 185	$ 185
27	Less PUC-ORDERED MAJOR OR BASELINE CAPITAL CREDITS	Note 3	$000s	$ -	$ (10)	$ (10)	$ (141)	$ (141)	$ (141)	$ (141)
28	Less Revenue Taxes on Line 27 at 8.885%		$000s	$ -	$ 1	$ 1	$ 12	$ 12	$ 12	$ 12
29	Net PUC-Ordered Major or Baseline Capital Credits	Lines 27 + 28	$000s	$ -	$ (9)	$ (9)	$ (128)	$ (128)	$ (128)	$ (128)
30	Total Annual Target Revenues									
31	August 23, 2018 Annualized Revenues with Interim Increase	Lines 5 + 23	$000s	$ 145,310						
32	June 1, 2019 Annualized Revenues + 2019 RAM Revenues	Lines 5 + 8 + 14 + 20 + 26 + 29	$000s		$ 149,842	$ 149,894				
33	June 1, 2020 Annualized Revenues + 2020 RAM Revenues	Lines 5 + 11 + 14 + 17 + 20 + 23 + 26 + 29	$000s				$ 154,892	$ 154,892		
34	June 1, 2020 Annualized Revenues + 2020 RAM Revenues + MPIR, accrued 5/1/23								[redacted]	
35	June 1, 2020 Annualized Revenues + 2020 RAM Revenues + MPIR, accrued 1/1/24									
36						Note 4				
37	Distribution of Target Revenues by Month in Dollars	Note 2	Note 2a	2019	2019	2020	2020	2021	2023	2024
38	January	8.38%	8.493%	$ 12,176,939		$ 12,561,126		$ 12,979,918	[redacted]	
39	February	7.50%	7.673%	$ 10,898,215		$ 11,242,058		$ 11,616,872		
40	March	8.06%	8.493%	$ 11,711,948		$ 12,081,465		$ 12,484,265		
41	April	7.85%	8.219%	$ 11,406,798		$ 11,766,687		$ 12,158,993		
42	May	8.18%	8.493%	$ 11,886,320		$ 12,261,338		$ 12,670,135		
43	June	8.19%	8.219%		$ 12,272,061		$ 12,685,624			
44	July	8.77%	8.493%		$ 13,141,144		$ 13,583,996			
45	August	9.00%	8.493%		$ 13,485,781		$ 13,940,246			
46	September	8.50%	8.219%		$ 12,736,571		$ 13,165,788			
47	October	8.73%	8.493%		$ 13,081,207		$ 13,522,039			
48	November	8.30%	8.219%		$ 12,436,887		$ 12,856,005			
49	December	8.54%	8.493%		$ 12 796 508		$ 13 227 745			
50	Total Distributed Target Revenues	100.00%	100.00%	$ 58,080,220	$ 89,950,159	$ 59,912,674	$ 92,981,443	$ 61,910,183		

Note 1 Column (c) Interim Decision and Order No. 35631, August 9, 2018, Docket No. 2017-0150. Exhibit A, page 1 of 4. Also see Maui Electric Correction to Attachment 6B in Statement of Probable Entitlement, August 2, 2018, Docket No. 2017-0150.

Column (d)-(g) Parties' Joint Proposed Revsied Schedules and Refund Plan, April 17, 2019, Docket No. 2017-0150. Exhibit 1C, page 1 of 48.

Note 2 RBA Tariff effective August 23, 2018 based on 2018 test year. Maui Electric Interim Increase Tariff Sheets, Docket No. 2017-0150, filed August 21, 2018.

Note 2a FOR ILLUSTRATION PURPOSES ONLY - Monthly Allocation Factors based on the number of days in the month as a percentage of the number of days in the year, with the allocation factor for February set such that the total of the monthly allocation factors sums to 100%. The use of these factors has not yet been approved for Maui Electric, but it is included here for illustrative purposes.

Note 3 Transmittal Nos. 20-01, 20-02, 20-03 Consolidated (Decoupling) - 2020 RBA Rate Adjustment, approved in Order No. 37150, filed May 28, 2020 updated target revenues for the removal of Phase 1 Grid Modernization project withholdings approved in Order No. 37146, Docket 2018-0141, retroactive to January 1, 2020.

Note 4 FOR ILLUSTRATION PURPOSES ONLY - MPIR Revenue accrual starting May 1, 2023 filed in Transmittal xx-xx, filed Month Day, Year.

Note 5 FOR ILLUSTRATION PURPOSES ONLY - MPIR Revenue annual true-up starting January 1, 2024 filed in Transmittal xx-xx, filed Month Day, Year.

SCHEDULE L
(To file by May 2023)
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MAUI ELECTRIC COMPANY, LTD.
DECOUPLING CALCULATION WORKBOOK
ILLUSTRATIVE MAJOR PROJECT INTERIM RECOVERY

The purpose of this Illustration is to reflect the inclusion of the Waena BESS Project upon project in service. The May 2023 filing will also include an update for all MPIR project costs recorded as of December 31, 2022 and filed as part of the February 2023 annual MPIR true-up filing.

Line No.	Description	Reference	Amount $000
	(a)	(b)	(c)
1	Grid Mod Phase 1 Project Docket No. 2018-0141	Note 1	$ 52
2	Waena BESS Project Docket No. xxxx-xxxx	Schedule L2	[redacted]
3	Total MPIR Recovery		[redacted]
4	Revenue Tax Factor (1/(1-8.885%))		1.0975
5	Major Project Interim Recovery Total		[redacted]
			To Sch B1

Note 1: Transmittal No. 20-01, 20-02, 20-03 Consolidated (Decoupling) - 2020 RBA Rate Adjustment, Attachment 2, Schedule L, filed June 5, 2020.

SCHEDULE L2
(To file by May 2023)
PAGE 1 OF 1

The purpose of ths Illustration is to reflect the mid-year convention for plant placed into service in April 2023 (Year 1). MPIR to be in effect until such costs are reflected in base rates.

MAUI ELECTRIC COMPANY, LTD.
DECOUPLING CALCULATION WORKBOOK
REVENUE REQUIREMENT AND DETERMINATION OF MAJOR PROJECT INTERIM RECOVERY
ILLUSTRATIVE MPIR PROJECT - WAENA BESS
($ in Thousands)

To the extent that recovery via the test year varies from actual costs incurred, a MPIR true-up adjustment will be made in the subsequent annual MPIR true-up filing.

Line No	Description	Reference	Recorded at 12/31/2022	Recorded at In-Service Date (April 2023)	Ending Balance as of 4/30/2023	Average Balance	MPIR
	(a)	(b)	(c)	(d)	(e)	(f)=((c)+(e))/2	(g)
	Return on Investment - Waena BESS						
1	Plant in Service (not to exceed PUC approved amount)	*Schedule L2.1*	-	60,003	60,003	30,002	
2	Accum Depreciation	*Note 1*	[redacted]				
3	Net Cost of Plant in Service						
4	ADIT	*MECO-WP-L2-002 p.1*					
5	State ITC	*MECO-WP-L2-002 p.3*					
6	Total Deductions						
7	Total Rate Base						
8	Average Rate Base					[redacted]	
9	Rate of Return (grossed-up for income taxes, before revenue taxes)	Note 2				9 34%	
10	Annualized Return on Investment (before revenue taxes)						[redacted]
11	Depreciation Expense (Note 1)					-	
11a	Amortization Expense	Not Applicable				-	
12	Operating & Maintenance Expense	Estimated; Note 3				[redacted]	
12a	Reconciliation of test year O&M to prior year actual O&M	Not Applicable					
13	Amortization of State ITC	Line 6, Col (d)				-	
14	Lease Rent Expense	Not Applicable				-	
15	Other Expense	Not Applicable				-	
16	Total Expenses						[redacted]
17	Total Annualized Major Project Interim Recovery						[redacted]
							To Sch L

Will be revised to reflect the most recent rate case rate of return.

Note 1: Depreciation expense is recorded beginning in the year after an asset is placed in service, therefore, depreciation expense is zero in year 1 The revenue requirement for year 2 and thereafter will include depreciation expense at existing, approved depreciation accrual rates at the time of filing

Note 2: Transmittal No 20-01, 20-02, 20-03 Consolidated (Decoupling) - 2020 RBA Rate Adjustment, Attachment 2, Schedule D, filed June 5, 2020

Note 3: Requesting PUC approval for incremental, on-going post in-service O&M costs per Exhibit 5, page 4

SCHEDULE L2.1
(To file by May 2023)
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MAUI ELECTRIC COMPANY, LTD.
DECOUPLING CALCULATION WORKBOOK
REVENUE REQUIREMENT AND DETERMINATION OF MAJOR PROJECT INTERIM RECOVERY
ILLUSTRATIVE MPIR PROJECT DETAIL
($ in Thousands)

Line No.	Grandparent # or Project #	Description	Docket No.	Actual In Service Date	Recorded at In Service Date
	(a)	(b)	(c)	(d)	(e)
1	MZ.005002	Waena BESS	Docket No. xxxx-xxxx	Apr 2023	60,003
2		**Total Project Costs**			**60,003**
					To Sch L2

Source: MECO-WP-L2-001

SCHEDULE La
(To file by Feb 2024)
PAGE 1 OF 1

MAUI ELECTRIC COMPANY, LTD.
DECOUPLING CALCULATION WORKBOOK
ILLUSTRATIVE MAJOR PROJECT INTERIM RECOVERY

The purpose of this Illustration is to reflect the inclusion of the Waena BESS Project in the year following project in service as part of the February 2024 annual MPIR true-up filing which will also include an update for all MPIR project costs recorded as of December 31, 2023 and 2024 activity. All other numbers from Transmittal No. 20-03 Consolidated (Decoupling) filing filed on June 5, 2020 will change based on actual information and actual decoupling filing approved at the time.

Line No.	Description	Reference	Amount $000
	(a)	(b)	(c)
1	Grid Mod Phase 1 Project Docket No. 2018-0141	Note 1	$ 52
2	Waena BESS Project Docket No. xxxx-xxxx	Schedule L2a	[redacted]
3	Total MPIR Recovery		[redacted]
4	Revenue Tax Factor (1/(1-8.885%))		1.0975
5	Major Project Interim Recovery Total		[redacted] *To Sch B1*

Note 1: Transmittal No. 20-01, 20-02, 20-03 Consolidated (Decoupling) - 2020 RBA Rate Adjustment, Attachment 2, Schedule L, filed June 5, 2020.

SCHEDULE L2a
(To file by Feb 2024)
PAGE 1 OF 1

The purpose of this Illustration is to reflect the calculation of MPIR recovery in the year following project in service filed as part of the annual MPIR true-up filing to be filed no later than February 2024. The Illustration starts with 2023 recorded costs plus 2024 activity. MPIR to be in effect until such costs are reflected in the next test year rate case base rates.

MAUI ELECTRIC COMPANY, LTD.
DECOUPLING CALCULATION WORKBOOK
REVENUE REQUIREMENT AND DETERMINATION OF MAJOR PROJECT INTERIM RECOVERY
ILLUSTRATIVE MPIR PROJECT - WAENA BESS
($ in Thousands)

To the extent that recovery via the test year varies from actual costs incurred, a MPIR true-up adjustment will be made in the subsequent annual MPIR true-up filing.

Line No	Description	Reference	Recorded at 12/31/2023	2024 Activity	Ending Balance as of 12/31/2024	Average Balance	MPIR
	(a)	(b)	(c)	(d)	(e)	(f)=((c)+(e))/2	(g)
	Return on Investment - Waena BESS						
1	Plant in Service (not to exceed PUC approved amount)	*Schedule L2.1*	[redacted]	[redacted]	[redacted]	[redacted]	
2	Accum Depreciation	*MECO-WP-L2-001*	[redacted]	[redacted]	[redacted]	[redacted]	
3	Net Cost of Plant in Service		[redacted]	[redacted]	[redacted]	[redacted]	
4	ADIT	*MECO-WP-L2-002 p.1*	[redacted]	[redacted]	[redacted]	[redacted]	
5	State ITC	*MECO-WP-L2-002 p.3*	[redacted]	[redacted]	[redacted]	[redacted]	
6	Total Deductions		[redacted]	[redacted]	[redacted]	[redacted]	
7	Total Rate Base		[redacted]	[redacted]	[redacted]	[redacted]	
8	Average Rate Base					[redacted]	
9	Rate of Return (grossed-up for income taxes, before revenue taxes)	Note 2				9 34%	
10	Annualized Return on Investment (before revenue taxes)						[redacted]
11	Depreciation Expense (Note 1)	*MECO-WP-L2-001*				[redacted]	
11a	Amortization Expense	Not Applicable				-	
12	Operating & Maintenance Expense	Estimated; Note 3				[redacted]	
12a	Reconciliation of test year O&M to prior year actual O&M	Not Applicable				-	
13	Amortization of State ITC	Line 6, Col (d)				[redacted]	
14	Lease Rent Expense	Not Applicable				-	
15	Other Expense	Not Applicable				-	
16	Total Expenses						[redacted]
17	Total Annualized Major Project Interim Recovery						[redacted]
							To Sch La

Will be revised to reflect the most recent rate case rate of return.

Note 1: Depreciation expense is recorded beginning in the year after an asset is placed in service, therefore, depreciation expense is zero in year 1 The revenue requirement for year 2 and thereafter will include depreciation expense at existing, approved depreciation accrual rates at the time of filing See further discussion at MECO-WP-L2-001

Note 2: Transmittal No 20-01, 20-02, 20-03 Consolidated (Decoupling) - 2020 RBA Rate Adjustment, Attachment 2, Schedule D, filed June 5, 2020

Note 3: Requesting PUC approval for incremental, on-going post in-service O&M costs per Exhibit 5, page 4

MAUI ELECTRIC COMPANY, LTD.
WAENA BESS
2023 and 2024 Major Projects Interim Recovery Depreciation Summary - ESTIMATE

To the extent that recovery via the test year varies from actual costs incurred, a MPIR true-up adjustment will be made in the subsequent annual MPIR true-up filing.

[1] Project #	[1] Project	Project Type	Date In Service	[1] Actual Net Plant Adds Thru 12/31/22	2023 Activity	[1] Actual Net Plant Adds Thru 12/31/23	Plant Acct	[2] PUC Approved Accrual Rate	[3] 2024 Depr
				(A)	(B)	(C) = (A) + (B)		(D)	(E) = (C) * (D)
MZ.005002	Transmission - 69 kV	Project	Apr 2023	-	[redacted]	[redacted]	353	[redacted]	[redacted]
MZ.005002	Substation	Project	Apr 2023		[redacted]	[redacted]	353	[redacted]	[redacted]
MZ.005002	BESS System	Project	Apr 2023	-	[redacted]	[redacted]	348	[4 [redacted] 4]	[redacted]
				-	60,003,159	60,003,159			2,915,311
						To Sch L2.1		*To Sch L2 / MECO-WP-L2-002 p.1*	

[1] Source: Schedule L2.1

[2] Depreciation rates applied will be per the latest Commission rate case order.
Per Docket No. 2016-0431, filed July 30, 2018, consolidated depreciation and amortization rates and revised CIAC amortization period will be effective with the date of interim or final rates in the Company's subsequent general rate case proceedings, beginning with MECO's 2018 test year general rate case.

[3] Included in MPIR recovery until total project costs are reflected in the next test year rate case base rates.

[4] The BESS system component of the project should be included in plant account # 348 – Energy Storage Equipment - Production. The Company will request in this Application that we are establishing a new asset category for accouting purposes: FERC Uniform System of Accounts plant account 348.00 Energy Storage Equipment – Production in accordance with the Commission's Decision and Order in the Hawaiian Electric Companies' most recent depreciation rates proceeding. The Company will also request for special accounting treatment to depreciate the battery related cost over 20 years (or 5% annually) as used in the RFP and revenue requirements for the annual depreciation expense.

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Pursuant To Protective Order No. ______

MAUI ELECTRIC COMPANY, LTD.
WAENA BESS
ADIT
DECEMBER 31, 2023 & 2024 ESTIMATE

To the extent that recovery via the test year varies from actual costs incurred, a MPIR true-up adjustment will be made in the subsequent annual MPIR true-up filing.

		Source	2023 Tax	AFUDC	Tax Capitalized Interest	State ITC	2023 Total	2024 Depreciation	State ITC	2024 Total
	FEDERAL DEFERRED TAXES									
1	Tax Depreciation	*MECO-WP-L2-002*	[redacted]							
2	Add back Book Depreciation	*MECO-WP-L2-001*								
3	State ITC amortization	*From Page 3*								
4	Subtotal	Line 1 + 2 + 3								
5	Effective Federal Tax Rate		19.7368%	19.7368%	19.7368%	19.7368%	19.7368%	19.7368%	19.7368%	19.7368%
6	Total Federal Deferred Taxes	Line 4 * Line 5	[redacted]							
	STATE DEFERRED TAXES									
7	Tax Depreciation	Line 1	[redacted]							
8	Add back Book Depreciation	Line 2								
9	State ITC amortization	Line 3								
10	Subtotal	Line 7 + 8 + 9								
11	Effective State Tax Rate		6.0150376%	6.0150376%	6.0150376%	6.0150376%	6.0150376%	6.0150376%	6.0150376%	6.0150376%
12	Total State Deferred Taxes	Line 10 * Line 11	[redacted]							
13	**TOTAL DEFERRED TAXES**	Line 6 + Line 12	[redacted]							
							To Sch L2			*To Sch L2a*
									Cumulativ	[redacted]
										To Sch L2a

* ADIT calculation resulting from the April 2023 plant additions will be included in the annual MPIR true-up filing to be filed no later than February 2024.

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Pursuant To Protective Order No. ____

MAUI ELECTRIC COMPANY, LTD.
WAENA BESS
TAX DEPRECIATION
DECEMBER 31, 2023 & 2024 ESTIMATE

To the extent that recovery via the test year varies from actual costs incurred, a MPIR true-up adjustment will be made in the subsequent annual MPIR true-up filing.

Project No.	Description	Book Basis	Less: AFUDC	Add: TCI	*From Page 5* Tax Basis	Plant Acct		Tax Life		Note 1 Year 1 2023	Note 1 Year 2 2024
MZ.005002	Transmission - 69 kV	[redacted]				353		[redacted]		[redacted]	
MZ.005002	Substation					353					
MZ.005002	BESS System					348	[1]		[2]		
	Total	60,003,159	(3,239,011)	1,956,152	58,720,300						
										To Page 1	*To Page 1*

Note: No bonus depreciation on public utility property placed in service after 12/31/17.
Note 1: Depreciation rate for recovery period is per IRS Publication 946, Table A-1

[1] The BESS system component of the project should be included in plant account # 348 – Energy Storage Equipment - Production. The Company will request in this Application that we are establishing a new asset category for accouting purposes: FERC Uniform System of Accounts plant account 348.00 Energy Storage Equipment – Production in accordance with the Commission's Decision and Order in the Hawaiian Electric Companies' most recent depreciation rates proceeding. The Company will also request for special accounting treatment to depreciate the battery related cost over 20 years (or 5% annually) as used in the RFP and revenue requirements for the annual depreciation expense.

[2] The BESS system qualifies as 7-year property with no class life for tax purposes under §168(e)(3)(C)(v).

MAUI ELECTRIC COMPANY, LTD.
WAENA BESS
TAX CREDITS
DECEMBER 31, 2023 & 2024 ESTIMATE

To the extent that recovery via the test year varies from actual costs incurred, a MPIR true-up adjustment will be made in the subsequent annual MPIR true-up filing.

State ITC Calculation

Total Materials & Outside Construction	[redacted]	***From Page 5***
State ITC %	4%	
State ITC	[redacted]	***To Sch L2, L2a***
2024 Book Amort of State ITC	[redacted]	***To Sch L2a***
State ITC, ending balance 2024	[redacted]	***To Sch L2a***

Note: 10 year State ITC tax amortization begins the year after an asset is placed in service.

MAUI ELECTRIC COMPANY, LTD.
WAENA BESS
AFUDC/TCI
DECEMBER 31, 2023 & 2024 ESTIMATE

To the extent that recovery via the test year varies from actual costs incurred, a MPIR true-up adjustment will be made in the subsequent annual MPIR true-up filing.

Project #	Description	*From Page 5* AFUDC	0.603935 TCI
MZ.005002	Transmission 69 kV	[redacted]	
MZ.005002	Substation		
MZ.005002	BESS System		
Total AFUDC		3,239,011	1,956,152

Source: Tax Return workpapers

Annual - TCI Incurred to AFUDC Incurred Ratio

	2015	2016	2017	2018	2019 Accrual	5 Yr Ave
TCI	[redacted]					
AFUDC						
Ratio	[redacted]					

To Page 5

MAUI ELECTRIC COMPANY, LTD.
WAENA BESS
COSTS BY YEAR
DECEMBER 31, 2023 & 2024 ESTIMATE

To the extent that recovery via the test year varies from actual costs incurred, a MPIR true-up adjustment will be made in the subsequent annual MPIR true-up filing.

Description	Transmission 69 kV	Substation	BESS System	Total	
AFUDC	[redacted]				*To Page 4*
LABOR					
MATERIALS					
OS CONTRACTS					[redacted]
OTHER: OTHER COSTS					*To Page 3*
OVERHEAD					
Total	[redacted]			60,003,159	*Exhibit 5, p.2*
Less: AFUDC	[redacted]				
Add: TCI	[redacted]				
0.603935					
From Page 4					
Tax Basis	[redacted]				*To Page 2*

Source: UI Planner

EXHIBIT 4: WAENA BATTERY ENERGY STORAGE SITE PLAN VIEW

EXHIBIT 4: WAENA BATTERY ENERGY STORAGE SITE PLAN VIEW

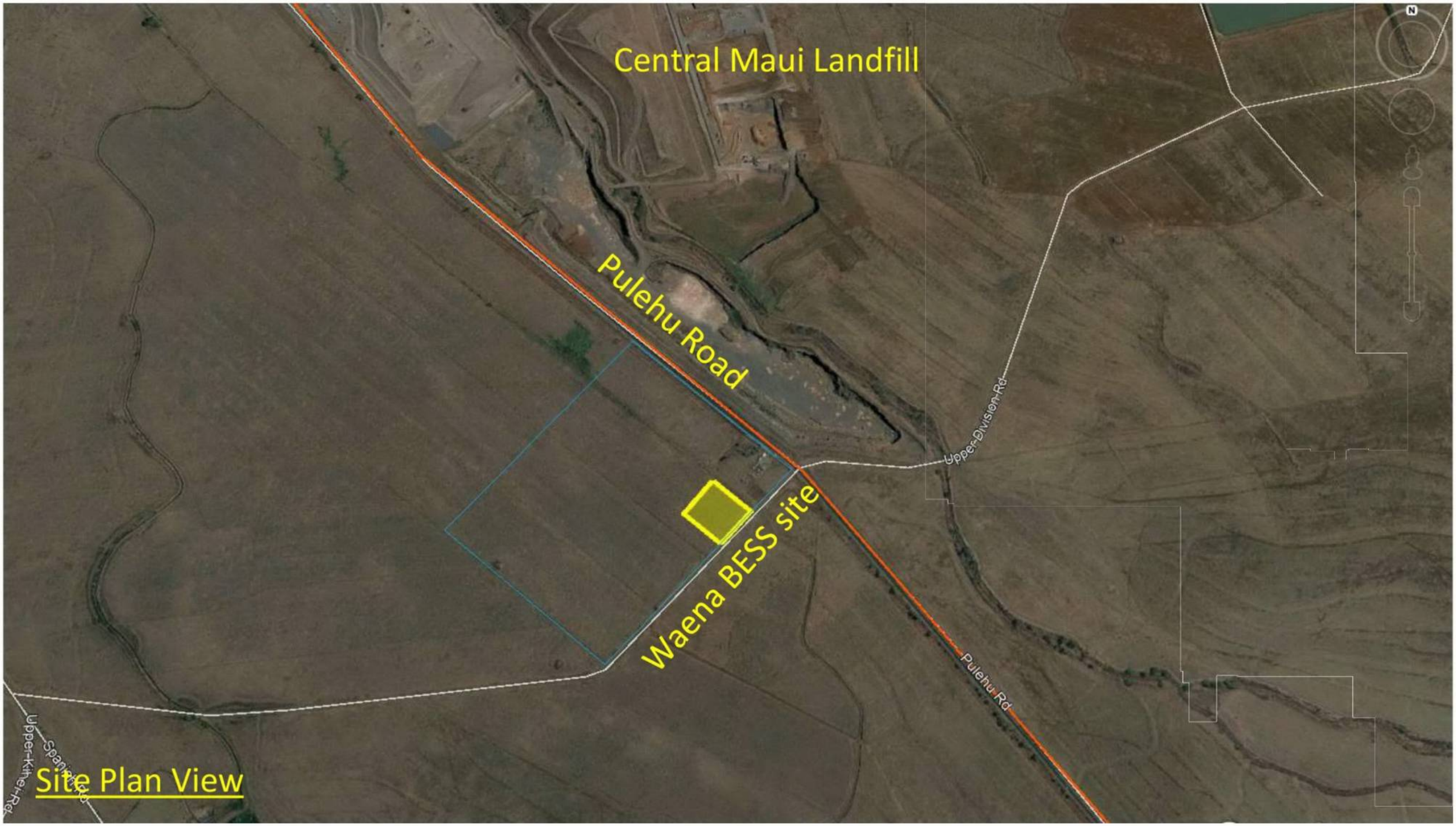

EXHIBIT 4
PAGE 2 OF 2

Waena Self Build Battery Energy Storage System (BESS) Rev Req and Bill Impact
Summary

		Waena Self Build BESS					
		Capital	**O&M**	**Total**			
Year		Revenue Requirement	Revenue Requirement	Revenue Requirement	Sales Forecast [1] (MWh)	Rate Impact cents per kWh	Bill Impact 500 kwh [2]
		a	b	c = sum	d	e = (c*100)/(d*1000)	f = e*5
1	**2023**	[redacted]			1,032,754	[redacted]	
2	**2024**				1,030,359		
3	**2025**				1,024,382		
4	**2026**				1,022,987		
5	**2027**				1,024,677		
6	**2028**				1,031,068		
7	**2029**				1,031,130		
8	**2030**				1,038,344		
9	**2031**				1,047,022		
10	**2032**				1,062,522		
11	**2033**				1,079,158		
12	**2034**				1,097,114		
13	**2035**				1,116,863		
14	**2036**				1,141,138		
15	**2037**				1,159,595		
16	**2038**				1,183,049		
17	**2039**				1,206,540		
18	**2040**				1,233,460		
19	**2041**				1,252,621		
20	**2042**				1,276,873		
Total		[redacted]				*Average* $	3.22
NPV @	6.93%	[redacted]					

Notes:
1. Estimated Maui Electric Sales Forecast for IGP 2020 obtained from Forecas ing Division.
2. Maui Electric typical residential energy consump ion, per month.

Waena Self Build Battery Energy Storage System (BESS) Rev Req and Bill Impact
Revenue Requirements Model
Assumptions

Manual input
MECO TY2018 Rate Case Dkt 2017-0150 Final D&O 36219

Cost of Capital Assumptions	Weight	Rate	Weighted Average	After-Tax Weighted Average	Weighted Average Revenue Requirement	Weighted Average Gross-up for Income Taxes
Short Term Debt	1.37%	3.00%	0.04%	0.03%	0.045%	0.04%
Long Term Debt (Taxable Debt)	38.68%	4.54%	1.76%	1.30%	1.927%	1.76%
Hybrids	1.96%	7.16%	0.14%	0.10%	0.154%	0.14%
Preferred Stock	0.98%	8.15%	0.08%	0.08%	0.118%	0.11%
Common Stock	57.02%	9.50%	5.42%	5.42%	8.007%	7.30%
	100.00%		7.43%	6.935%	10.251%	9.340%

Tax Assumptions		Effective
Federal Income Tax Rate	21.00%	19.74%
State Income Tax Rate	6.40%	6.02%
		25.75%

State Investment Tax Credit (ITC)[1]	4.00%	
Accelerated State ITC Amortization Period[1]	10	
Public Service Company Tax	5.885%	
PUC Fee	0.500%	
Franchise Tax	2.500%	
Composite Revenue Tax Rate	8.885%	1.09751

Project Assumptions

		Plant Add Date
Capital Investment[2]	$ 60,003,158	2023
Cost Recovery	MPIR	

Depreciation

Expected Useful Life[3]	20	
MACRS Tax Life ("Tax Life")	7	half-year convention, table A-1
Tax Class Life ("Class Life")	12	half-year convention, table A-8

O&M

O&M[5] [redacted]ee Calculation - O&M Tab

Escalation Rate 2.0%

Notes:
1. To be consistent with the other Self Build bids, the State ITC Amortization is accelerated over a ten-year period per HECO 2017 TY Rate Case Parties' Stipulated Settlement Letter in Docket No. 2016-032
2. Capital Investment costs provided by Project Management.
3. Expected useful life per Tesla Bid and confirmed with Engineering.
4. Tax Life for BESS connected to grid is 7 years per HEI Taxes.
5. Total O&M costs from Power Supply Engineering, see O&M Costs tab.

Waena Self Build Battery Energy Storage System (BESS) Rev Req and Bill Impact

Revenue Requirements Model - Calculations

		1	2	3	4	5	6	7	8	9	10	11	12
Manual input		1	2	3	4	5	6	7	8	9	10	11	12
O&M													
Escalation Rate		1.00	1.00	1.00	1.02	1.04	1.06	1.08	1.10	1.13	1.15	1.17	1.20
O&M		-	-	-	-	-	-	-	-	-	-	-	-
Plant Asset Depreciation													
Book Depreciation													
Book Depreciation Rates		0.000%	5.263%	5.263%	5.263%	5.263%	5.263%	5.263%	5.263%	5.263%	5.263%	5.263%	5.263%
Depreciation Expense		-	3,158,061	3,158,061	3,158,061	3,158,061	3,158,061	3,158,061	3,158,061	3,158,061	3,158,061	3,158,061	3,158,061
Accumulated Depreciation		-	3,158,061	6,316,122	9,474,183	12,632,244	15,790,305	18,948,366	22,106,427	25,264,488	28,422,549	31,580,610	34,738,671
Tax Depreciation													
Tax Depreciation Rates (Straight Line)	12	5.000%	10.000%	10.000%	10.000%	10.000%	10.000%	10.000%	10.000%	10.000%	10.000%	5.000%	0.000%
Tax Basis (S/L)	0.0%	-	-	-	-	-	-	-	-	-	-	-	-
Tax Depreciation Rates (MACRS)	7	14.290%	24.490%	17.490%	12.490%	8.930%	8.920%	8.930%	4.460%	0.000%	0.000%	0.000%	0.000%
NonRB Financed Tax Basis (MACRS)	100.0%	8,574,451	14,694,774	10,494,552	7,494,394	5,358,282	5,352,282	5,358,282	2,676,141	-	-	-	-
Tax Depreciation		8,574,451	14,694,774	10,494,552	7,494,394	5,358,282	5,352,282	5,358,282	2,676,141	-	-	-	-
Accumulated Tax Depreciation		8,574,451	23,269,225	33,763,777	41,258,172	46,616,454	51,968,736	57,327,018	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158
State Investment Tax Credit (ITC)													
Book													
State ITC Amortization Rate		0.000%	10.000%	10.000%	10.000%	10.000%	10.000%	10.000%	10.000%	10.000%	10.000%	10.000%	0.000%
Amortization of State ITC	4.00%	-	240,013	240,013	240,013	240,013	240,013	240,013	240,013	240,013	240,013	240,013	-
Accumulated Amortization		-	240,013	480,025	720,038	960,051	1,200,063	1,440,076	1,680,088	1,920,101	2,160,114	2,400,126	2,400,126
Deferred ITC		2,400,126	2,160,114	1,920,101	1,680,088	1,440,076	1,200,063	960,051	720,038	480,025	240,013	0	0
Tax		2,400,126											
Deferred Tax Calculation													
Book Accumulated Depreciation		-	3,158,061	6,316,122	9,474,183	12,632,244	15,790,305	18,948,366	22,106,427	25,264,488	28,422,549	31,580,610	34,738,671
Tax Accumulated Depreciation		8,574,451	23,269,225	33,763,777	41,258,172	46,616,454	51,968,736	57,327,018	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158
Book/Tax Acc Depr Difference		(8,574,451)	(20,111,164)	(27,447,655)	(31,783,989)	(33,984,210)	(36,178,431)	(38,378,652)	(37,896,732)	(34,738,671)	(31,580,610)	(28,422,549)	(25,264,488)
Deferred ITC		2,400,126	2,160,114	1,920,101	1,680,088	1,440,076	1,200,063	960,051	720,038	480,025	240,013	0	0
Net Deferred Tax Asset (Liability)		(1,590,005)	(4,622,733)	(6,573,825)	(7,752,320)	(8,380,726)	(9,007,587)	(9,635,993)	(9,573,697)	(8,822,245)	(8,070,793)	(7,319,341)	(6,506,080)
Deferred Tax Base		6,174,325	11,776,725	7,576,504	4,576,346	2,440,234	2,434,233	2,440,234	(241,907)	(2,918,048)	(2,918,048)	(2,918,048)	(3,158,061)
Deferred Taxes - Federal		1,218,617	2,324,354	1,495,363	903,226	481,625	480,441	481,625	(47,745)	(575,931)	(575,931)	(575,931)	(623,302)
Deferred Taxes - State excluding credit		371,388	708,374	455,730	275,269	146,781	146,420	146,781	(14,551)	(175,522)	(175,522)	(175,522)	(189,959)
Change in Deferred Taxes		1,590,005	3,032,728	1,951,092	1,178,495	628,406	626,861	628,406	(62,296)	(751,452)	(751,452)	(751,452)	(813,260)
Accumulated Deferred Taxes		1,590,005	4,622,733	6,573,825	7,752,320	8,380,726	9,007,587	9,635,993	9,573,697	8,822,245	8,070,793	7,319,341	6,506,080
check		-	-	-	-	-	-	-	-	-	-	-	-
Change in Deferred ITC		2,400,126	(240,013)	(240,013)	(240,013)	(240,013)	(240,013)	(240,013)	(240,013)	(240,013)	(240,013)	(240,013)	-
		2,400,126	(240,013)	(240,013)	(240,013)	(240,013)	(240,013)	(240,013)	(240,013)	(240,013)	(240,013)	(240,013)	-
Rate Base and Financing													
Investment: (Rate Base)													
Gross Plant		60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158
Accumulated Depreciation		-	3,158,061	6,316,122	9,474,183	12,632,244	15,790,305	18,948,366	22,106,427	25,264,488	28,422,549	31,580,610	34,738,671
Accumulated Deferred Taxes		1,590,005	4,622,733	6,573,825	7,752,320	8,380,726	9,007,587	9,635,993	9,573,697	8,822,245	8,070,793	7,319,341	6,506,080
Accumulated Deferred ITC		2,400,126	2,160,114	1,920,101	1,680,088	1,440,076	1,200,063	960,051	720,038	480,025	240,013	0	0
Ending Net Investment	-	56,013,027	50,062,251	45,193,110	41,096,567	37,550,113	34,005,203	30,458,749	27,602,996	25,436,400	23,269,804	21,103,208	18,758,407
Average Net Investment		28,006,514	53,037,639	47,627,681	43,144,839	39,323,340	35,777,658	32,231,976	29,030,873	26,519,698	24,353,102	22,186,506	19,930,808

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Revenue Requirements Model - Calculations													
Manual input		1	2	3	4	5	6	7	8	9	10	11	12
Average Financing:													
Short Term Debt	1.37%	383,600	726,447	652,348	590,947	538,604	490,040	441,475	397,630	363,235	333,560	303,884	272,989
Long Term Debt (Revenue Bonds)	38.68%	10,832,618	20,514,388	18,421,874	16,687,959	15,209,845	13,838,413	12,466,982	11,228,829	10,257,534	9,419,518	8,581,502	7,709,022
Taxable Debt	1.96%	547,592	1,037,009	931,231	843,581	768,862	699,536	630,210	567,621	518,521	476,160	433,798	389,693
Preferred Stock	0.98%	274,310	519,478	466,490	422,582	385,153	350,425	315,696	284,343	259,747	238,527	217,306	195,212
Common Equity	57.02%	15,968,393	30,240,318	27,155,738	24,599,768	22,420,875	20,399,244	18,377,613	16,552,449	15,120,660	13,885,338	12,650,016	11,363,891
Total Financing		28,006,514	53,037,639	47,627,681	43,144,839	39,323,340	35,777,658	32,231,976	29,030,873	26,519,698	24,353,102	22,186,506	19,930,808
Return on Investment													
Short Term Debt	3.00%	11,508	21,793	19,570	17,728	16,158	14,701	13,244	11,929	10,897	10,007	9,117	8,190
Long Term Debt (Taxable Debt)	4.54%	491,801	931,353	836,353	757,633	690,527	628,264	566,001	509,789	465,692	427,646	389,600	349,990
Hybrids	7.16%	39,208	74,250	66,676	60,400	55,051	50,087	45,123	40,642	37,126	34,093	31,060	27,902
Total Interest Expense		542,516	1,027,396	922,600	835,762	761,736	693,052	624,368	562,359	513,715	471,746	429,777	386,081
Preferred Dividends	8.15%	22,356	42,337	38,019	34,440	31,390	28,560	25,729	23,174	21,169	19,440	17,710	15,910
Net Income on Common	9.50%	1,516,997	2,872,830	2,579,795	2,336,978	2,129,983	1,937,928	1,745,873	1,572,483	1,436,463	1,319,107	1,201,752	1,079,570
Income Taxes													
Income Before Pref Dividends		1,539,354	2,915,168	2,617,814	2,371,418	2,161,373	1,966,488	1,771,602	1,595,657	1,457,632	1,338,547	1,219,462	1,095,479
Income Before Taxes (including ITC)		2,073,256	3,926,251	3,525,765	3,193,910	2,911,014	2,648,535	2,386,057	2,149,087	1,963,191	1,802,803	1,642,415	1,475,431
Investment Tax Credit		-	240,013	240,013	240,013	240,013	240,013	240,013	240,013	240,013	240,013	240,013	-
Income Before Taxes (excluding ITC)		2,073,256	3,686,238	3,285,752	2,953,898	2,671,001	2,408,523	2,146,044	1,909,074	1,723,178	1,562,790	1,402,402	1,475,431
Federal Income Tax		409,195	774,918	695,875	630,377	574,542	522,737	470,932	424,162	387,472	355,816	324,161	291,203
State Income Tax		124,707	236,165	212,076	192,115	175,099	159,310	143,522	129,268	118,087	108,439	98,792	88,748
State Investment Tax Credit		-	(240,013)	(240,013)	(240,013)	(240,013)	(240,013)	(240,013)	(240,013)	(240,013)	(240,013)	(240,013)	-
Total State Tax		124,707	(3,847)	(27,937)	(47,898)	(64,914)	(80,702)	(96,490)	(110,744)	(121,926)	(131,573)	(141,221)	88,748
Total Taxes		533,902	771,071	667,938	582,479	509,628	442,035	374,442	313,418	265,546	224,243	182,940	379,951
Revenue Requirement Calculation													
Revenue Requirement Factors	[redacted]												
Revenue Requirement													
Revenue Taxes													
Income Before Depr, Int, Inc Tax		2,615,772	7,871,696	7,366,413	6,947,721	6,590,798	6,259,636	5,928,474	5,629,495	5,394,954	5,192,597	4,990,240	5,019,573
Depreciation Expense		-	3,158,061	3,158,061	3,158,061	3,158,061	3,158,061	3,158,061	3,158,061	3,158,061	3,158,061	3,158,061	3,158,061
O&M		-	-	-	-	-	-	-	-	-	-	-	-
Interest Expense		542,516	1,027,396	922,600	835,762	761,736	693,052	624,368	562,359	513,715	471,746	429,777	386,081
Income Before Income Taxes		2,073,256	3,686,238	3,285,752	2,953,898	2,671,001	2,408,523	2,146,044	1,909,074	1,723,178	1,562,790	1,402,402	1,475,431
Income Taxes - Federal		409,195	774,918	695,875	630,377	574,542	522,737	470,932	424,162	387,472	355,816	324,161	291,203
Income Taxes - State		124,707	236,165	212,076	192,115	175,099	159,310	143,522	129,268	118,087	108,439	98,792	88,748
State ITC		-	(240,013)	(240,013)	(240,013)	(240,013)	(240,013)	(240,013)	(240,013)	(240,013)	(240,013)	(240,013)	-
Total Income Taxes		533,902	771,071	667,938	582,479	509,628	442,035	374,442	313,418	265,546	224,243	182,940	379,951
Preferred Dividends		22,356	42,337	38,019	34,440	31,390	28,560	25,729	23,174	21,169	19,440	17,710	15,910
Net Income for Common		[redacted]											
	check	-	-	-	-	-	-	-	-	-	-	-	-
	ROE	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%

EXHIBIT 5
PA[redacted]E 4 OF 21

Waena Self Build Battery Energy Storage
Revenue Requirements Model - Calculati

	13	14	15	16	17	18	19	20	21	22	23	24
Manual input	13	14	15	16	17	18	19	20	21	22	23	24
O&M												
Escalation Rate	1.22	1.24	1.27	1.29	1.32	1.35	1.37	1.40	1.43	1.46	1.49	1.52
O&M	-	-	-	-	-	-	-	-	-	-	-	-
Plant Asset Depreciation												
Book Depreciation												
Book Depreciation Rates	5.263%	5.263%	5.263%	5.263%	5.263%	5.263%	5.263%	5.263%	0.000%	0.000%	0.000%	0.000%
Depreciation Expense	3,158,061	3,158,061	3,158,061	3,158,061	3,158,061	3,158,061	3,158,061	3,158,061	-	-	-	-
Accumulated Depreciation	37,896,732	41,054,793	44,212,854	47,370,915	50,528,976	53,687,037	56,845,097	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158
Tax Depreciation												
Tax Depreciation Rates (Straight Line)	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
Tax Basis (S/L)	-	-	-	-	-	-	-	-	-	-	-	-
Tax Depreciation Rates (MACRS)	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
NonRB Financed Tax Basis (MACRS)	-	-	-	-	-	-	-	-	-	-	-	-
Tax Depreciation	-	-	-	-	-	-	-	-	-	-	-	-
Accumulated Tax Depreciation	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158
State Investment Tax Credit (ITC)												
Book												
State ITC Amortization Rate	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
Amortization of State ITC	-	-	-	-	-	-	-	-	-	-	-	-
Accumulated Amortization	2,400,126	2,400,126	2,400,126	2,400,126	2,400,126	2,400,126	2,400,126	2,400,126	2,400,126	2,400,126	2,400,126	2,400,126
Deferred ITC	0	0	0	0	0	0	0	0	0	0	0	0
Tax												
Deferred Tax Calculation												
Book Accumulated Depreciation	37,896,732	41,054,793	44,212,854	47,370,915	50,528,976	53,687,037	56,845,097	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158
Tax Accumulated Depreciation	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158
Book/Tax Acc Depr Difference	(22,106,427)	(18,948,366)	(15,790,305)	(12,632,244)	(9,474,183)	(6,316,122)	(3,158,061)	-	-	-	-	-
Deferred ITC	0	0	0	0	0	0	0	0	0	0	0	0
Net Deferred Tax Asset (Liability)	(5,692,820)	(4,879,560)	(4,066,300)	(3,253,040)	(2,439,780)	(1,626,520)	(813,260)	0	0	0	0	0
Deferred Tax Base	(3,158,061)	(3,158,061)	(3,158,061)	(3,158,061)	(3,158,061)	(3,158,061)	(3,158,061)	(3,158,061)	-	-	-	-
Deferred Taxes - Federal	(623,302)	(623,302)	(623,302)	(623,302)	(623,302)	(623,302)	(623,302)	(623,302)	-	-	-	-
Deferred Taxes - State excluding credit	(189,959)	(189,959)	(189,959)	(189,959)	(189,959)	(189,959)	(189,959)	(189,959)	-	-	-	-
Change in Deferred Taxes	(813,260)	(813,260)	(813,260)	(813,260)	(813,260)	(813,260)	(813,260)	(813,260)	-	-	-	-
Accumulated Deferred Taxes	5,692,820	4,879,560	4,066,300	3,253,040	2,439,780	1,626,520	813,260	0	0	0	0	0
check	-	-	0	0	0	0	0	0	0	0	0	0
Change in Deferred ITC	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-
Rate Base and Financing												
Investment: (Rate Base)												
Gross Plant	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158
Accumulated Depreciation	37,896,732	41,054,793	44,212,854	47,370,915	50,528,976	53,687,037	56,845,097	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158
Accumulated Deferred Taxes	5,692,820	4,879,560	4,066,300	3,253,040	2,439,780	1,626,520	813,260	0	0	0	0	0
Accumulated Deferred ITC	0	0	0	0	0	0	0	0	0	0	0	0
Ending Net Investment	16,413,606	14,068,805	11,724,005	9,379,204	7,034,403	4,689,602	2,344,801	(0)	(0)	(0)	(0)	(0)
Average Net Investment	17,586,007	15,241,206	12,896,405	10,551,604	8,206,803	5,862,002	3,517,201	1,172,400	(0)	(0)	(0)	(0)

Revenue Requirements Model - Calculati												
Manual input	13	14	15	16	17	18	19	20	21	22	23	24
Average Financing:												
Short Term Debt	240,872	208,756	176,640	144,523	112,407	80,291	48,174	16,058	(0)	(0)	(0)	(0)
Long Term Debt (Revenue Bonds)	6,802,078	5,895,134	4,988,191	4,081,247	3,174,303	2,267,359	1,360,416	453,472	(0)	(0)	(0)	(0)
Taxable Debt	343,847	298,001	252,155	206,308	160,462	114,616	68,769	22,923	(0)	(0)	(0)	(0)
Preferred Stock	172,246	149,280	126,314	103,348	80,382	57,415	34,449	11,483	(0)	(0)	(0)	(0)
Common Equity	10,026,963	8,690,035	7,353,106	6,016,178	4,679,249	3,342,321	2,005,393	668,464	(0)	(0)	(0)	(0)
Total Financing	17,586,007	15,241,206	12,896,405	10,551,604	8,206,803	5,862,002	3,517,201	1,172,400	(0)	(0)	(0)	(0)
Return on Investment												
Short Term Debt	7,226	6,263	5,299	4,336	3,372	2,409	1,445	482	(0)	(0)	(0)	(0)
Long Term Debt (Taxable Debt)	308,814	267,639	226,464	185,289	144,113	102,938	61,763	20,588	(0)	(0)	(0)	(0)
Hybrids	24,619	21,337	18,054	14,772	11,489	8,206	4,924	1,641	(0)	(0)	(0)	(0)
Total Interest Expense	340,660	295,239	249,817	204,396	158,975	113,553	68,132	22,711	(0)	(0)	(0)	(0)
Preferred Dividends	14,038	12,166	10,295	8,423	6,551	4,679	2,808	936	(0)	(0)	(0)	(0)
Net Income on Common	952,561	825,553	698,545	571,537	444,529	317,520	190,512	63,504	(0)	(0)	(0)	(0)
Income Taxes												
Income Before Pref Dividends	966,600	837,720	708,840	579,960	451,080	322,200	193,320	64,440	(0)	(0)	(0)	(0)
Income Before Taxes (including ITC)	1,301,851	1,128,270	954,690	781,110	607,530	433,950	260,370	86,790	(0)	(0)	(0)	(0)
Investment Tax Credit	-	-	-	-	-	-	-	-	-	-	-	-
Income Before Taxes (excluding ITC)	1,301,851	1,128,270	954,690	781,110	607,530	433,950	260,370	86,790	(0)	(0)	(0)	(0)
Federal Income Tax	256,944	222,685	188,426	154,167	119,907	85,648	51,389	17,130	(0)	(0)	(0)	(0)
State Income Tax	78,307	67,866	57,425	46,984	36,543	26,102	15,661	5,220	(0)	(0)	(0)	(0)
State Investment Tax Credit	-	-	-	-	-	-	-	-	-	-	-	-
Total State Tax	78,307	67,866	57,425	46,984	36,543	26,102	15,661	5,220	(0)	(0)	(0)	(0)
Total Taxes	335,251	290,551	245,851	201,151	156,450	111,750	67,050	22,350	(0)	(0)	(0)	(0)
Revenue Requirement Calculation												
Revenue Requirement Factors	[redacted]											
Revenue Requirement												
Revenue Taxes												
Income Before Depr, Int, Inc Tax	4,800,571	4,581,570	4,362,569	4,143,567	3,924,566	3,705,564	3,486,563	3,267,562	(0)	(0)	(0)	(0)
Depreciation Expense	3,158,061	3,158,061	3,158,061	3,158,061	3,158,061	3,158,061	3,158,061	3,158,061	-	-	-	-
O&M	-	-	-	-	-	-	-	-	-	-	-	-
Interest Expense	340,660	295,239	249,817	204,396	158,975	113,553	68,132	22,711	(0)	(0)	(0)	(0)
Income Before Income Taxes	1,301,851	1,128,270	954,690	781,110	607,530	433,950	260,370	86,790	(0)	(0)	(0)	(0)
Income Taxes - Federal	256,944	222,685	188,426	154,167	119,907	85,648	51,389	17,130	(0)	(0)	(0)	(0)
Income Taxes - State	78,307	67,866	57,425	46,984	36,543	26,102	15,661	5,220	(0)	(0)	(0)	(0)
State ITC	-	-	-	-	-	-	-	-	-	-	-	-
Total Income Taxes	335,251	290,551	245,851	201,151	156,450	111,750	67,050	22,350	(0)	(0)	(0)	(0)
Preferred Dividends	14,038	12,166	10,295	8,423	6,551	4,679	2,808	936	(0)	(0)	(0)	(0)
Net Income for Common	[redacted]											
	-	-	-	-	-	-	(0)	(0)	-	-	-	-
	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%

Waena Self Build Battery Energy Storage												
Revenue Requirements Model - Calculati												
Manual input	25	26	27	28	29	30	31	32	33	34	35	36
O&M												
Escalation Rate	1.55	1.58	1.61	1.64	1.67	1.71	1.74	1.78	1.81	1.85	1.88	1.92
O&M	-	-	-	-	-	-	-	-	-	-	-	-
Plant Asset Depreciation												
Book Depreciation												
Book Depreciation Rates	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	-
Accumulated Depreciation	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158
Tax Depreciation												
Tax Depreciation Rates (Straight Line)	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
Tax Basis (S/L)	-	-	-	-	-	-	-	-	-	-	-	-
Tax Depreciation Rates (MACRS)	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
NonRB Financed Tax Basis (MACRS)	-	-	-	-	-	-	-	-	-	-	-	-
Tax Depreciation	-	-	-	-	-	-	-	-	-	-	-	-
Accumulated Tax Depreciation	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158
State Investment Tax Credit (ITC)												
Book												
State ITC Amortization Rate	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
Amortization of State ITC	-	-	-	-	-	-	-	-	-	-	-	-
Accumulated Amortization	2,400,126	2,400,126	2,400,126	2,400,126	2,400,126	2,400,126	2,400,126	2,400,126	2,400,126	2,400,126	2,400,126	2,400,126
Deferred ITC	0	0	0	0	0	0	0	0	0	0	0	0
Tax												
Deferred Tax Calculation												
Book Accumulated Depreciation	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158
Tax Accumulated Depreciation	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158
Book/Tax Acc Depr Difference	-	-	-	-	-	-	-	-	-	-	-	-
Deferred ITC	0	0	0	0	0	0	0	0	0	0	0	0
Net Deferred Tax Asset (Liability)	0	0	0	0	0	0	0	0	0	0	0	0
Deferred Tax Base	-	-	-	-	-	-	-	-	-	-	-	-
Deferred Taxes - Federal	-	-	-	-	-	-	-	-	-	-	-	-
Deferred Taxes - State excluding credit	-	-	-	-	-	-	-	-	-	-	-	-
Change in Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-	-
Accumulated Deferred Taxes	0	0	0	0	0	0	0	0	0	0	0	0
check	0	0	0	0	0	0	0	0	0	0	0	0
Change in Deferred ITC	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-
Rate Base and Financing												
Investment: (Rate Base)												
Gross Plant	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158
Accumulated Depreciation	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158
Accumulated Deferred Taxes	0	0	0	0	0	0	0	0	0	0	0	0
Accumulated Deferred ITC	0	0	0	0	0	0	0	0	0	0	0	0
Ending Net Investment	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Average Net Investment	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)

EXHIBIT 5
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Revenue Requirements Model - Calculati												
Manual input	25	26	27	28	29	30	31	32	33	34	35	36
Average Financing:												
Short Term Debt	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Long Term Debt (Revenue Bonds)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Taxable Debt	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Preferred Stock	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Common Equity	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Total Financing	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Return on Investment												
Short Term Debt	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Long Term Debt (Taxable Debt)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Hybrids	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Total Interest Expense	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Preferred Dividends	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Net Income on Common	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Income Taxes												
Income Before Pref Dividends	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Income Before Taxes (including ITC)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Investment Tax Credit	-	-	-	-	-	-	-	-	-	-	-	-
Income Before Taxes (excluding ITC)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Federal Income Tax	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
State Income Tax	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
State Investment Tax Credit	-	-	-	-	-	-	-	-	-	-	-	-
Total State Tax	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Total Taxes	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Revenue Requirement Calculation												
Revenue Requirement Factors	[redacted]											
Revenue Requirement												
Revenue Taxes												
Income Before Depr, Int, Inc Tax	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	-
O&M	-	-	-	-	-	-	-	-	-	-	-	-
Interest Expense	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Income Before Income Taxes	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Income Taxes - Federal	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Income Taxes - State	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
State ITC	-	-	-	-	-	-	-	-	-	-	-	-
Total Income Taxes	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Preferred Dividends	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Net Income for Common	[redacted]											
	-	-	-	-	-	-	-	-	-	-	-	-
	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%

Confidential Information Deleted
Pursuant To Protective Order ______

Waena Self Build Battery Energy Storage												
Revenue Requirements Model - Calculati												
Manual input	37	38	39	40	41	42	43	44	45	46	47	48
O&M												
Escalation Rate	1.96	2.00	2.04	2.08	2.12	2.16	2.21	2.25	2.30	2.34	2.39	2.44
O&M	-	-	-	-	-	-	-	-	-	-	-	-
Plant Asset Depreciation												
Book Depreciation												
Book Depreciation Rates	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	-
Accumulated Depreciation	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158
Tax Depreciation												
Tax Depreciation Rates (Straight Line)	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
Tax Basis (S/L)	-	-	-	-	-	-	-	-	-	-	-	-
Tax Depreciation Rates (MACRS)	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
NonRB Financed Tax Basis (MACRS)	-	-	-	-	-	-	-	-	-	-	-	-
Tax Depreciation	-	-	-	-	-	-	-	-	-	-	-	-
Accumulated Tax Depreciation	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158
State Investment Tax Credit (ITC)												
Book												
State ITC Amortization Rate	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
Amortization of State ITC	-	-	-	-	-	-	-	-	-	-	-	-
Accumulated Amortization	2,400,126	2,400,126	2,400,126	2,400,126	2,400,126	2,400,126	2,400,126	2,400,126	2,400,126	2,400,126	2,400,126	2,400,126
Deferred ITC	0	0	0	0	0	0	0	0	0	0	0	0
Tax												
Deferred Tax Calculation												
Book Accumulated Depreciation	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158
Tax Accumulated Depreciation	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158
Book/Tax Acc Depr Difference	-	-	-	-	-	-	-	-	-	-	-	-
Deferred ITC	0	0	0	0	0	0	0	0	0	0	0	0
Net Deferred Tax Asset (Liability)	0	0	0	0	0	0	0	0	0	0	0	0
Deferred Tax Base	-	-	-	-	-	-	-	-	-	-	-	-
Deferred Taxes - Federal	-	-	-	-	-	-	-	-	-	-	-	-
Deferred Taxes - State excluding credit	-	-	-	-	-	-	-	-	-	-	-	-
Change in Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-	-
Accumulated Deferred Taxes	0	0	0	0	0	0	0	0	0	0	0	0
check	0	0	0	0	0	0	0	0	0	0	0	0
Change in Deferred ITC	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-
Rate Base and Financing												
Investment: (Rate Base)												
Gross Plant	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158
Accumulated Depreciation	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158
Accumulated Deferred Taxes	0	0	0	0	0	0	0	0	0	0	0	0
Accumulated Deferred ITC	0	0	0	0	0	0	0	0	0	0	0	0
Ending Net Investment	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Average Net Investment	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)

Revenue Requirements Model - Calculati												
Manual input	37	38	39	40	41	42	43	44	45	46	47	48
Average Financing:												
Short Term Debt	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Long Term Debt (Revenue Bonds)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Taxable Debt	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Preferred Stock	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Common Equity	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Total Financing	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Return on Investment												
Short Term Debt	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Long Term Debt (Taxable Debt)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Hybrids	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Total Interest Expense	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Preferred Dividends	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Net Income on Common	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Income Taxes												
Income Before Pref Dividends	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Income Before Taxes (including ITC)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Investment Tax Credit	-	-	-	-	-	-	-	-	-	-	-	-
Income Before Taxes (excluding ITC)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Federal Income Tax	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
State Income Tax	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
State Investment Tax Credit	-	-	-	-	-	-	-	-	-	-	-	-
Total State Tax	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Total Taxes	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Revenue Requirement Calculation												
Revenue Requirement Factors	[redacted]											
Revenue Requirement												
Revenue Taxes												
Income Before Depr, Int, Inc Tax	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	-
O&M	-	-	-	-	-	-	-	-	-	-	-	-
Interest Expense	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Income Before Income Taxes	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Income Taxes - Federal	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Income Taxes - State	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
State ITC	-	-	-	-	-	-	-	-	-	-	-	-
Total Income Taxes	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Preferred Dividends	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Net Income for Common	[redacted]											
	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%

Confidential Information Deleted
Pursuant To Protective Order ______

Waena Self Build Battery Energy Storage												
Revenue Requirements Model - Calculati												
Manual input	49	50	51	52	53	54	55	56	57	58	59	60
O&M												
Escalation Rate	2.49	2.54	2.59	2.64	2.69	2.75	2.80	2.86	2.91	2.97	3.03	3.09
O&M	-	-	-	-	-	-	-	-	-	-	-	-
Plant Asset Depreciation												
Book Depreciation												
Book Depreciation Rates	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	-
Accumulated Depreciation	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158
Tax Depreciation												
Tax Depreciation Rates (Straight Line)	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
Tax Basis (S/L)	-	-	-	-	-	-	-	-	-	-	-	-
Tax Depreciation Rates (MACRS)	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
NonRB Financed Tax Basis (MACRS)	-	-	-	-	-	-	-	-	-	-	-	-
Tax Depreciation	-	-	-	-	-	-	-	-	-	-	-	-
Accumulated Tax Depreciation	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158
State Investment Tax Credit (ITC)												
Book												
State ITC Amortization Rate	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
Amortization of State ITC	-	-	-	-	-	-	-	-	-	-	-	-
Accumulated Amortization	2,400,126	2,400,126	2,400,126	2,400,126	2,400,126	2,400,126	2,400,126	2,400,126	2,400,126	2,400,126	2,400,126	2,400,126
Deferred ITC	0	0	0	0	0	0	0	0	0	0	0	0
Tax												
Deferred Tax Calculation												
Book Accumulated Depreciation	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158
Tax Accumulated Depreciation	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158
Book/Tax Acc Depr Difference	-	-	-	-	-	-	-	-	-	-	-	-
Deferred ITC	0	0	0	0	0	0	0	0	0	0	0	0
Net Deferred Tax Asset (Liability)	0	0	0	0	0	0	0	0	0	0	0	0
Deferred Tax Base	-	-	-	-	-	-	-	-	-	-	-	-
Deferred Taxes - Federal	-	-	-	-	-	-	-	-	-	-	-	-
Deferred Taxes - State excluding credit	-	-	-	-	-	-	-	-	-	-	-	-
Change in Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-	-
Accumulated Deferred Taxes	0	0	0	0	0	0	0	0	0	0	0	0
check	0	0	0	0	0	0	0	0	0	0	0	0
Change in Deferred ITC	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-
Rate Base and Financing												
Investment: (Rate Base)												
Gross Plant	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158
Accumulated Depreciation	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158	60,003,158
Accumulated Deferred Taxes	0	0	0	0	0	0	0	0	0	0	0	0
Accumulated Deferred ITC	0	0	0	0	0	0	0	0	0	0	0	0
Ending Net Investment	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Average Net Investment	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)

Revenue Requirements Model - Calculati												
Manual input	49	50	51	52	53	54	55	56	57	58	59	60
Average Financing:												
Short Term Debt	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Long Term Debt (Revenue Bonds)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Taxable Debt	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Preferred Stock	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Common Equity	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Total Financing	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Return on Investment												
Short Term Debt	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Long Term Debt (Taxable Debt)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Hybrids	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Total Interest Expense	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Preferred Dividends	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Net Income on Common	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Income Taxes												
Income Before Pref Dividends	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Income Before Taxes (including ITC)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Investment Tax Credit	-	-	-	-	-	-	-	-	-	-	-	-
Income Before Taxes (excluding ITC)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Federal Income Tax	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
State Income Tax	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
State Investment Tax Credit	-	-	-	-	-	-	-	-	-	-	-	-
Total State Tax	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Total Taxes	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Revenue Requirement Calculation												
Revenue Requirement Factors	[redacted]											
Revenue Requirement												
Revenue Taxes												
Income Before Depr, Int, Inc Tax	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	-
O&M	-	-	-	-	-	-	-	-	-	-	-	-
Interest Expense	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Income Before Income Taxes	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Income Taxes - Federal	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Income Taxes - State	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
State ITC	-	-	-	-	-	-	-	-	-	-	-	-
Total Income Taxes	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Preferred Dividends	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Net Income for Common	[redacted]											
	-	-	-	-	-	-	-	-	-	-	-	-
	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%

Confidential Information Deleted
Pursuant To Protective Order ______

EXHIBIT 5
PAGE 12 OF 21

Waena Self Build Battery Energy Storage		
Revenue Requirements Model - Calculati		
	Manual input	Total
	O&M	
	Escalation Rate	
	O&M	-
Plant Asset Depreciation		
	Book Depreciation	
	Book Depreciation Rates	100.00%
	Depreciation Expense	60,003,158
	Accumulated Depreciation	
	Tax Depreciation	
	Tax Depreciation Rates (Straight Line)	100.00%
	Tax Basis (S/L)	-
	Tax Depreciation Rates (MACRS)	100.00%
	NonRB Financed Tax Basis (MACRS)	60,003,158
	Tax Depreciation	60,003,158
	Accumulated Tax Depreciation	
	State Investment Tax Credit (ITC)	
	Book	
	State ITC Amortization Rate	100.00%
	Amortization of State ITC	2,400,126
	Accumulated Amortization	
	Deferred ITC	
	Tax	
Deferred Tax Calculation		
	Book Accumulated Depreciation	
	Tax Accumulated Depreciation	
	Book/Tax Acc Depr Difference	
	Deferred ITC	
	Net Deferred Tax Asset (Liability)	
	Deferred Tax Base	
	Deferred Taxes - Federal	
	Deferred Taxes - State excluding credit	
	Change in Deferred Taxes	
	Accumulated Deferred Taxes	
	check	
	Change in Deferred ITC	
Rate Base and Financing		
	Investment: (Rate Base)	
	Gross Plant	
	Accumulated Depreciation	
	Accumulated Deferred Taxes	
	Accumulated Deferred ITC	
	Ending Net Investment	
	Average Net Investment	

Revenue Requirements Model - Calculati	
Manual input	Total
Average Financing:	
Short Term Debt	
Long Term Debt (Revenue Bonds)	
Taxable Debt	
Preferred Stock	
Common Equity	
Total Financing	
Return on Investment	
Short Term Debt	
Long Term Debt (Taxable Debt)	
Hybrids	
Total Interest Expense	
Preferred Dividends	
Net Income on Common	
Income Taxes	
Income Before Pref Dividends	
Income Before Taxes (including ITC)	
Investment Tax Credit	
Income Before Taxes (excluding ITC)	
Federal Income Tax	
State Income Tax	
State Investment Tax Credit	
Total State Tax	
Total Taxes	
Revenue Requirement Calculation	
Revenue Requirement Factors	
Revenue Requirement	
Revenue Taxes	
Income Before Depr, Int, Inc Tax	
Depreciation Expense	
O&M	
Interest Expense	
Income Before Income Taxes	
Income Taxes - Federal	
Income Taxes - State	
State ITC	
Total Income Taxes	
Preferred Dividends	
Net Income for Common	

Waena Self Build Battery Energy Storage System (BESS) Rev Req and Bill Impact

O&M Revenue Requirement

	Year	Escalation	O&M[1]	O&M Revenue Requirement Factor	O&M Revenue Requirement
1	**2023**	1.00	[redacted]	1.09751	[redacted]
2	**2024**	1.00		1.09751	
3	**2025**	1.00		1.09751	
4	**2026**	1.00		1.09751	
5	**2027**	1.00		1.09751	
6	**2028**	1.00		1.09751	
7	**2029**	1.00		1.09751	
8	**2030**	1.00		1.09751	
9	**2031**	1.00		1.09751	
10	**2032**	1.00		1.09751	
11	**2033**	1.00		1.09751	
12	**2034**	1.00		1.09751	
13	**2035**	1.00		1.09751	
14	**2036**	1.00		1.09751	
15	**2037**	1.00		1.09751	
16	**2038**	1.00		1.09751	
17	**2039**	1.00		1.09751	
18	**2040**	1.00		1.09751	
19	**2041**	1.00		1.09751	
20	**2042**	1.00		1.09751	
	Total		[redacted]		[redacted]
		Check	-		

Notes:

1. Includes total costs and CMA, see O&M Escalation tab.

Waena Self Build Battery Energy Storage System (BESS) Rev Req and Bill Impact

Tax Depreciation

Tax Depreciation Factors

Manual input	Years	1	2	3	4	5	6	7	8	9	10	11	12	13
Tax Depreciation Rates (Straight Line)														
	-													
	3	16.670%	33.330%	33.330%	16.670%									
	5	10.000%	20.000%	20.000%	20.000%	20.000%	10.000%							
	7	7.140%	14.290%	14.290%	14.280%	14.290%	14.280%	14.290%	7.140%					
	10	5.000%	10.000%	10.000%	10.000%	10.000%	10.000%	10.000%	10.000%	10.000%	10.000%	5.000%		
	15	3.330%	6.670%	6.670%	6.670%	6.670%	6.670%	6.670%	6.660%	6.670%	6.660%	6.670%	6.660%	6.670%
	20	2.500%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%
	25	2.000%	4.000%	4.000%	4.000%	4.000%	4.000%	4.000%	4.000%	4.000%	4.000%	4.000%	4.000%	4.000%
	28	1.786%	3.571%	3.571%	3.571%	3.571%	3.571%	3.572%	3.571%	3.572%	3.571%	3.572%	3.571%	3.572%
	30	1.667%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.333%	3.334%
	35	1.429%	2.857%	2.857%	2.857%	2.857%	2.857%	2.857%	2.857%	2.857%	2.857%	2.857%	2.857%	2.857%
	50	1.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%
Source: IRS Publication 946, Table A-8														
Tax Depreciation Rates (MACRS)														
	-													
	3	33.330%	44.450%	14.810%	7.410%									
	5	20.000%	32.000%	19.200%	11.520%	11.520%	5.760%							
	7	14.290%	24.490%	17.490%	12.490%	8.930%	8.920%	8.930%	4.460%					
	10	10.000%	18.000%	14.400%	11.520%	9.220%	7.370%	6.550%	6.550%	6.560%	6.550%	3.280%		
	15	5.000%	9.500%	8.550%	7.700%	6.930%	6.230%	5.900%	5.900%	5.910%	5.900%	5.910%	5.900%	5.910%
	20	3.750%	7.219%	6.677%	6.177%	5.713%	5.285%	4.888%	4.522%	4.462%	4.461%	4.462%	4.461%	4.462%
Source: IRS Publication 946, Table A-1														

Manual input	Years	14	15	16	17	18	19	20	21	22	23	24	25	26
Tax Depreciation Rates (Straight Line)														
	-													
	3													
	5													
	7													
	10													
	15	6.660%	6.670%	3.330%										
	20	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	2.500%					
	25	4.000%	4.000%	4.000%	4.000%	4.000%	4.000%	4.000%	4.000%	4.000%	4.000%	4.000%	4.000%	2.000%
	28	3.571%	3.572%	3.571%	3.572%	3.571%	3.572%	3.571%	3.572%	3.571%	3.572%	3.571%	3.572%	3.571%
	30	3.333%	3.334%	3.333%	3.334%	3.333%	3.334%	3.333%	3.334%	3.333%	3.334%	3.333%	3.334%	3.333%
	35	2.857%	2.857%	2.857%	2.857%	2.857%	2.857%	2.857%	2.857%	2.857%	2.857%	2.857%	2.857%	2.857%
	50	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%
Tax Depreciation Rates (MACRS)														
	-													
	3													
	5													
	7													
	10													
	15	5.900%	5.910%	2.950%										
	20	4.461%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%	2.231%					

Waena Self Build Battery Ener

Tax Depreciation Factors

Tax Depreciation

Manual input	Years	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54	55	56	57
Tax Depreciation Rates (Str																																
	-																															
	3																															
	5																															
	7																															
	10																															
	15																															
	20																															
	25																															
	28	3.572%	3.571%	1.786%																												
	30	3.334%	3.333%	3.334%	3.333%	1.667%																										
	35	2.857%	2.858%	2.857%	2.858%	2.857%	2.858%	2.857%	2.858%	2.857%	1.429%																					
	50	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	1.000%						
Source: IRS Publication 946, Ta																																
Tax Depreciation Rates (MA																																
	-																															
	3																															
	5																															
	7																															
	10																															
	15																															
	20																															
Source: IRS Publication 946, Ta																																

Waena Self Build Battery Ener

Tax Depreciation Factors

Manual input	Years	58	59	60	Total
Tax Depreciation Rates (Str					
	-				
	3				100.000%
	5				100.000%
	7				100.000%
	10				100.000%
	15				100.000%
	20				100.000%
	25				100.000%
	28				100.000%
	30				100.000%
	35				100.000%
	50				100.000%
Source: IRS Publication 946, Ta					
Tax Depreciation Rates (MA					
	-				
	3				100.000%
	5				100.000%
	7				100.000%
	10				100.000%
	15				100.000%
	20				100.000%
Source: IRS Publication 946, Ta					

Waena Self Build Battery Energy Storage System (BESS) Rev Req and Bill Impact

Capital Costs

	Transmission	Transmission	BESS
Life:	20.00	20.00	20.00

[redacted]

Source: UI Planner

Waena Self Build Battery Energy Storage System (BESS) Rev Req and Bill Impact
From "Final Waena O_M Cost Proposal UPDATED.xlsx
Note: All numbers are hardcoded below.

Costs by Year Checked by DD

No	Year	Annual Cost (2020 Dollars)	4 year periodic costs (2020 Dollars)	5 year periodic costs (2020 Dollars)	Total Costs (2020 Dollars)	Total Costs (2% Escalation)	CMA (No Escalation)	al Ins. Prem (2% Esc)	Total O&M Costs by Year	
1	2023	[redacted]								
2	2024									
3	2025									
4	2026									
5	2027									
6	2028									
7	2029									
8	2030									
9	2031									
10	2032									
11	2033									
12	2034									
13	2035									
14	2036									
15	2037									
16	2038									
17	2039									
18	2040									
19	2041									
20	2042									
									[redacted]	Total

Maui Electric Company, Ltd. - Consolidated
IGP 2020 Sales Forecast
Years 2020-2050
MWh Sales

Year	R	G	J	P	F	Total
2020	375,089	81,401	257,031	368,118	5,390	1,087,028
2021	363,064	79,966	249,396	364,149	4,954	1,061,529
2022	351,624	79,703	246,473	360,315	4,009	1,042,124
2023	348,215	79,975	243,775	358,039	2,750	1,032,754
2024	347,224	80,761	241,781	357,823	2,771	1,030,359
2025	344,977	81,281	239,106	356,242	2,777	1,024,382
2026	344,607	82,082	237,480	356,027	2,790	1,022,987
2027	346,617	82,985	236,246	356,026	2,804	1,024,677
2028	349,487	84,349	236,586	357,822	2,825	1,031,068
2029	349,927	85,209	235,671	357,491	2,830	1,031,130
2030	354,230	86,449	236,053	358,768	2,844	1,038,344
2031	359,616	87,637	236,764	360,148	2,857	1,047,022
2032	369,290	89,004	238,530	362,819	2,878	1,062,522
2033	383,321	90,041	239,362	363,551	2,884	1,079,158
2034	396,447	91,326	241,001	365,443	2,897	1,097,114
2035	410,959	92,588	242,881	367,524	2,910	1,116,863
2036	427,297	94,223	245,913	370,773	2,932	1,141,138
2037	441,189	95,371	247,949	372,149	2,937	1,159,595
2038	457,213	96,847	251,064	374,975	2,951	1,183,049
2039	473,054	98,329	254,196	377,997	2,964	1,206,540
2040	489,529	100,124	258,218	382,604	2,986	1,233,460
2041	503,121	101,293	260,739	384,477	2,991	1,252,621
2042	519,127	102,730	264,276	387,735	3,004	1,276,873
2043	535,499	104,177	267,718	390,849	3,017	1,301,261
2044	550,430	105,868	271,835	395,371	3,039	1,326,542
2045	563,978	107,021	274,534	397,541	3,044	1,346,119
2046	578,401	108,412	277,985	400,634	3,058	1,368,490
2047	592,811	109,793	281,522	403,580	3,071	1,390,776
2048	607,887	111,569	286,171	408,076	3,093	1,416,795
2049	620,454	112,970	288,725	410,255	3,098	1,435,501
2050	634,799	114,380	292,440	413,886	3,111	1,458,616

Hawaiian Electric / Maui Electric / Hawaiʻi Electric Light	**Project Justification with Business Case Support for the Waena Battery Energy Storage System Project**

DATE	PROJECT NAME
9/1/20	Waena Battery Energy Storage System Project
PREPARER/ SUBMITTER	**COMPANY / SPONSOR(S)**
Shelley Takasato	Hawaiian Electric Company / Robert C. Isler

Note: References to exhibit numbers in this document refer to exhibits included in the accompanying Application.

EXECUTIVE SUMMARY

The Hawaiian Electric Companies issued the Stage 2 Request for Proposals for Variable Renewable Dispatchable Generation and Energy Storage for the Island of Maui (the "Stage 2 RFP")[1] in accordance with Commission Order No. 36474[2] in Docket 2017-0352. The Stage 2 RFP solicited proposals for, among other things, up to 40 megawatts ("MW") battery energy storage, and allowed the Company to submit self-build proposals subject to the requirements of the Stage 2 RFP.

The Waena BESS Project was submitted in response to the Stage 2 RFP as a Company self-build proposal. As outlined in the RFP, a robust three phase bid evaluation process, approved by the Commission and overseen by the Independent Observer, evaluated the projects submitted for consideration in response to the Stage 2 RFP, and selected the Waena BESS to the Final Award Group as providing a necessary amount of energy storage capability at the best value to customers.

The proposed Waena BESS Project is a 40 MW/160 megawatt-hour ("MWh") BESS at Maui Electric's Company-owned Waena site in Central Maui, Kahului, Hawaiʻi. The facility will maintain the required performance and capacities specified in the Stage 2 RFP for a 20-year

[1] See Docket 2017-0352, *Request for Proposals for Variable Renewable Dispatchable Generation and Energy Storage Island of Hawaiʻi*, Book 5 of 7, filed August 22, 2019.
[2] See Docket 2017-0352, Order No. 36474, filed August 15, 2019.

period. The Project is scheduled to commence construction in March 2022 with an in-service date of April 2023, at a total estimated capital cost of $60.0 million.

Maui Electric respectfully submits that the proposed Project is reasonable and in the public interest, and should be approved, as:

- The Project was selected through a Commission-approved competitive procurement process that has resulted in the lowest cost to customers for a required resource;
- The Project incorporates the cost, performance, and financial obligations required of a self-build project as required by the Stage 2 RFP, which are intended to be equivalent to the Energy Storage Power Purchase Agreement contracting mechanism requirements (See Exhibit 1).[3]

BUSINESS CASE

A. Replacement Capacity for Maui

Based on the company needs identified in the PSIP[4], the Company proposed including in the Stage 2 RFP a requirement for up to 40 MW of grid-tied energy storage to provide the replacement capacity needed to enable the retirement of Kahului Power Plant ("KPP"). The Commission approved the Stage 2 RFP with this requirement included.

The Stage 2 RFP[5] notes that Maui's capacity could be met by standalone storage or generation paired with storage that allowed for grid charging. The Companies estimated in the PSIP that 40 MW and 160 MWh per day is required by the Maui grid. Without a replacement of this size available on the system the result is less reliability of electric service to customers as resources will be reduced once KPP is not available.

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[3] See Docket No. 2014-0183, D&O 34696 at 3: "The commission expects the Companies to continuously improve and refine their resource planning tools and methods, and employ these tools to support appropriate competitive procurement processes and Project applications in the near term."

[4] See Docket no. 2014-0183, Chapter 7 of The Hawaiian Electric Companies' Power Supply Improvement Plan Update Report, filed December 23, 2016 and accepted by the Commission in Decision and Order no. 34696, filed July 2017

[5] April 1, 2019 Stage 2 draft filing, Exhibit 1, p.3

B. Waena BESS Project Meets Energy Storage RFP Requirements

The self-build team developed the Waena BESS Project to provide 40 MW of the storage capacity requested in the Stage 2 RFP. Technical and performance details were provided in the Company's self-build proposal, including commitments to Project schedule, capacity, and system performance for the 20 year Project life. The Waena BESS Project will improve grid reliability by providing a capacity resource to the grid which will be lost when KPP is no longer available. In addition to the capacity performance requirements, the Waena BESS Project meets all of the other specified requirements of the Stage 2 RFP, including the ability to perform energy shifting, grid-following services, black-start, and grid forming services.

The Company's RFP Team, under the observation of the Independent Observer approved by the Commission, evaluated the Waena BESS proposal for compliance with the Stage 2 RFP requirements, and determined that the proposed Project satisfied 40MW of the required storage requirement identified in the Stage 2 RFP, as well as all of the other requirements of the RFP.

C. Waena BESS is Lowest Cost to Customers

The Stage 2 RFP provided the first test of the full implementation of the Framework for Competitive Bidding, including the participation of the Company self-build team in direct competition with third party providers. A Commission-approved Code of Conduct was implemented, and executed through a set of procedures that was intended to ensure that any Company self-build bids were developed on the same basis as others', and that the resultant bids were evaluated fairly, in an unbiased manner, and provided the required resources at the lowest cost to customers that the market could provide. To ensure that this Code and the supporting procedures were implemented as intended, an Independent Observer was assigned to monitor compliance.

Given that the Stage 2 RFP was executed successfully, and the Waena BESS was selected to the Final Award Group to provide 40 MW of capacity for the island of Maui, the evaluation process determined that the proposed Project provided the proposed resource at the lowest cost to customers that the market can provide. Specifically:

1. Capital Cost

As detailed in Exhibit 2, the total capital cost upon which the Waena BESS Project's successful bid was based is $60.0 million. This is proposed in the Application as a capped amount, and in the event that actual costs exceed this amount the Company would not be eligible for recovery of any capital cost in excess of $60.0 million. In the event that actual costs are less than this amount, the Company has proposed a Shared Savings Mechanism through which customers would realize 10% of any cost savings under the bid price of $60.0 million. The RFP Team was not allowed to consider any potential customer savings due to the utility self-build project costs coming in under the bid price, and the self-build proposal was selected based on the full $60.0 million capital price. The potential for customers to realize 10% of any capital cost savings is an additional benefit of the project which would not be provided by an independent power producer ("IPP").

2. O&M

The annual O&M costs for the Project, which were included in the successful bid, are detailed in Exhibit 5. The amounts detailed are proposed as capped amounts. In the event that actual annual O&M costs are less than these amounts, the Company has proposed a Shared Savings Mechanism through which customers would realize 10% of any cost savings under the bid O&M amounts. The RFP Team was not allowed to consider any potential customer savings due to the utility self-build project costs coming in under the bid price, and the self-build proposal was selected based on the full O&M pricing provided. The potential for customers to realize 10% of any O&M cost savings is an additional benefit of the project which would not be provided by an independent power producer ("IPP").

3. Revenue Requirements

The resultant revenue requirements for the Project, which were calculated in the bid and served as the basis for selection, are detailed in Exhibit 5.

4. Net Costs

The Company seeks recovery of Project costs through the MPIR mechanism. Under the MPIR Guidelines, any cost savings that would be realized due to the Project's implementation should be returned to customers. For cost savings such as reduced purchased power or reduced fuel costs, this is accomplished through an existing mechanism such as PPAC or ECRC. For other costs, recovery of a project's actual costs is offset by the expected cost reductions that the utility expects to realize through implementing the proposed project.

In order to be consistent with how an IPP would be compensated, the Company seeks recovery of the full amount of the Project costs upon which the successful bid was based, without any offset for any expected utility cost savings that may result from the Project's implementation.

Fuel or purchased power cost changes will flow back to customers through PPAC and ECRC as is typical of the Company's capital project.

SUMMARY

The proposed Project provides Maui customers a required grid resource at the lowest price available, and should be approved on this basis.

Exhibit 7 Community Outreach Plan

To maintain the trust of the community during throughout the project, Maui Electric will maximize transparency and opportunities for stakeholder input. We will engage stakeholders and affected communities throughout the process and maintain channels that will allow for questions and comments to be received and addressed. An important outcome of the stakeholder meetings was identifying how the project will impact the community in both positive and potentially negative ways, and to gaining insight on mitigative measures that would be acceptable.

Key stakeholders include, but are not limited to the following:

1. Aha Moku Council and other cultural leaders
2. Council Chair Alice Lee
3. Councilmember Yuki Lei Sugimura
4. Councilmember Tasha Kama
5. Councilmember Shane Sinenci
6. Department of Land and Natural Resources – Division of Forestry & Wildlife
7. Governor's Maui Representative, Leah Belmonte
8. Maui Nui Seabird Recovery Project
9. Maui Tomorrow
10. Representative Kyle Yamashita
11. Senator J. Kalani English
12. Sierra Club
13. PUC Maui Representative
14. Users of Lower Kula Road – Upcountry community

Stakeholders were briefed on the merits of the project concurrently with submitting the proposal, including the location, system size, acreage needed, and the need that will be filled by this project. All concerns and comments were documented, reviewed, and addressed to the extent possible before any wider public outreach was conducted. To maintain open communication with key stakeholders, the following methods are being used:

1. Regular email updates to those who signed up to receive them.
2. A project email address was set up for stakeholders and the general public to submit their questions and comments throughout the duration of the project – Community Relations will receive the incoming email messages and disperse them to the Self-Build Team for prompt follow up.
3. The Maui Electric Call Center staff was provided with talking points and a phone number to call should Maui Electric customers inquire about the proposed project. The talking points will include: Type of energy resource being proposed, location, benefits of the project and contact information for futher inquiry (Community Relations Specialist).
4. Presentations about the project are available on our website.

Self-Build Team Community Outreach Contact:

Community Relations Specialist: Kuhea Asiu

Contact Information: Kuhea.Asiu@mauielectric.com

Consultants:

Planning Solutions was contracted early in the process to assist with the Community Outreach efforts. They have extensive experience working with communities on Maui and the cultural sensitivities that must be taken into account. They have worked in focused consultations as well as larger public meetings.

All outreach efforts have been clearly documented, which will help the team to keep track of the stakeholders and community groups that were contacted, as well as the content of those discussions. A clear record also helps the team to determine if any individual or stakeholder group has been missed in the process. Lastly, the outreach record may be needed to demonstrate that efforts to genuinely engage the community were made and can show the details of those efforts.

The Community Relations Specialist will continually assess the community's temperature regarding the project and keep the project team informed. Any issues that appear to be escalating or have the potential to do so will be addressed as expediently as possible to avoid negative attention towards the proposed project. Monitoring social media for any misinformation will be key to preventing unnecessary conflict around the project.

The following dates were the community outreach meetings held by the self-build team:

February 26, 2020

Project Email Live

MauiBESS@hawaiianelectric.com

Waena BESS Stakeholder meeting – Environmental Leaders – Including:

Alex de Roode, Maui County Energy Commissioner

Makale'a Ane, Maui County Environmental Coordinator

Kahului Baseyard Auditorium

1:00 pm

Meeting with Councilmember Tasha Kama

City & County Building, Wailuku

11:00am

Meeting with Councilmember Yuki Lei Sugimura

City & County Building, Wailuku

3:00pm

Waena BESS Stakeholder Meeting – Cultural Leaders

Kahului Baseyard Auditorium

5:30pm

March 1, 2020

www.hawaiianelectric.com/selfbuildprojects website live

March 7, 2020

Paid notice regarding public meeting placed in *Maui News*

March 13-16, 2020

Due to physical distancing measures and state shelter-in-place mandate for COVID-19, the public meeting at Kahului Base Yard on April 8 was cancelled, and instead a virtual public hearing planned on Akakū Community TV.

March 27, 2020

News release on virtual public meeting distributed

Promotion of virtual public meeting on Hawaiian Electric's social media platforms

March 30, 2020

Meeting with Donna Clayton, President, Pukalani Community Association

Phone Conference

1:00pm

March 31, 2020

Meeting with Eric Nakagawa, Maui County Director of Environmental Management

Virtual Meeting

2:00pm

April 4, 2020

Paid notice regarding virtual public meeting details placed in *Maui News*

April 5, 2020

Email reminders sent to the following:

1. Alex de Roode, County Energy Commissioner
2. Community Association Leaders
3. County Councilmembers
4. County Director of Environmental Management
5. Cultural Stakeholders
6. Environmental Stakeholders
7. Emily Erickson, Community Stakeholder
8. Farmer’s Union
9. Leah Belmonte, Governor’s Maui Rep
10. Makale‘a Ane, County Environmental Coord.
11. Maui Conservation Alliance

12. Maui County Farm Bureau
13. Naomi Landgraf, Maui
14. Pukalani Community Association
15. PUC Representative
16. State Representatives
17. State Senators

April 8, 2020

Live, virtual, interactive presentation of project on Akakū Community Television Channel 54, Facebook Live, and WebEx

Ongoing Activities:

1. Monitor mauibess@hawaiianelectric.com email
2. Respond to community and government questions, concerns, feedback
3. Update the website, including FAQs
4. Public relations/publicity – respond to media inquiries and/or arrange interviews with SMEs, as needed
5. Plan for any in-person meetings if necessary when restrictions for COVID-19 are lifted.

Future Activities:

1. Stakeholder and community notification that the Application has been submitted
2. Solicitation of additional comments for 30 days, and provision of responses
3. Filing of additional comments and responses to the application

Exhibit 8: Public Comments, Questions, and Responses

RECEIVED FROM	DATE	QUESTION/COMMENT	RESPONSES
Councilmember	2/26/2020	Who makes the selection for the winning project?	A combination of the RFP team and Independent Observer will review the proposals submitted and make their selections. The selection process is outlined in the RFP.
		Do you know how many other bidders there were? Only because Maui people want to know what Maui people are doing. There are good people and bad people.	As a bidder, we are not aware or know of the other developers bidding into the RFP.
		What is the evening peak?	Usually between 5pm and 9pm, the demand for electricity reaches its highest point. For Maui, this is approximately 200 MW.
		And you guys are saying you can do this project?	Yes, we can do this project if we are selected.
		Would your team submit the application?	Yes the Self-Build Team will be submitting the application on behalf of the Company
		So you'll be hiring new employees or shifting existing employees?	We are not aware of any new hires that would be required for this project
		Who's on the other end of the Maui BESS email?	Community Relations (Kuhea Asiu) and Shelley Takasato
		If you're approaching your colleagues on the other side of the firewall, what are the key differentiators compared to your competitors (i.e. what does the company have to offer over its competitors).	As part of the Competitive Bidding Framing, the Self-build team is not allowed to discuss anything to do with the RFP with our collegues on the RFP team
		You only collect on what you spent on the project, that's a good point that you should share at your community meetings.	Noted
		What's the life of this facility?	20 years
		What happens after 20 years? Is the plan written someplace?	Our proposal will include a decommissioning plan which outlines what will need to be done when project is no longer active.
		The other bidders can talk to anyone they want, right? They may not necessarily come talk to us. I just think about our community and how diverse they are.	Yes, Developers can talk to anyone. The self-Build group does not have visibility to that information.
		The challenge for the client in this situation is, I've got all of these parts, but how do I unify all of them in a compatible manner?	Yes, The RFP team and IO have a difficult task of determining what projects are best for Maui and the community.
		What if the vendor fails?	There are remedies in place in case a vendor is not able to execute in the RFP.
		How many batteries do we need?	The RFP indicated 40MW, 4-hour batteries
		Will I see a reduction in my electric bill?	That will need to be provided after the projects are selected and the detailed financials are complete.

RECEIVED FROM	DATE	QUESTION/COMMENT	RESPONSES
		Will this project allow you/us to take advantage of energy when it's cheaper?	The batteries will be grid-tied taking energy from all resources including renewable resources.
		So it's not going to look much different than a substation?	Batteries will look like shipping containers set on concrete pads.
		You folks own the land?	Yes, the Waena Site is owned by the Company
Councilmember	2/26/2020	When you submitted your project, were you prohibited from special privileges?	Yes, the Self-build team is required to comply with the Competitive Bidding Framework and Code of Conduct to restrict any special privileges
		What is a docket?	A Docket is a proceeding before the PUC, initiated by a request or notification for their review, and resulting in a Decision and Order from the Commission.
		I received an email about a project from Honolulu, was that associated with this RFP?	It may have been
		In order for Hawaiian Electric to achieve the state's aggressive goal, they put out this RFP?	Yes, to ensure we get the best projects for the customers and meet the deadline of 2045 the RFP was issued
		I recommend reaching out to Kula Ag Park, Maui County Farm Bureau, Farmers Union, Pukalani Community Association	Yes, we will reach out to them
		What do you think the challenges are in winning the bid?	The biggest challenge for us as the utility is that our competitors may be specialized in this type of project and technology, whereas we maintain a broad array of systems.
		I think this is really good.	Thank you for your support.
		Are you building something similar in other places?	Yes, the self-build team is proposing projects in other places.
		How many customers will this project satisfy?	All customers on the grid will be served by this project.
		Are there any cultural sites known in the area?	In our preliminary assessments of the site none were identified
		Are you going to meet with the environmentalists who may be concerned about birds, bats, etc?	Yes, we are meeting with environmental stakeholders and conservation professionals today to get their input on this project.
		How will any of this disrupt traffic along Pulehu Road?	We don't anticipate impacting traffic on Pulehu Road. During construction we may have shipments that need to be delivered but can schedule that during off peak hours. After construction when the project is in service, there will only be monthly maintenance activities. This will not be a manned facility.
		I think Mahi Pono opened up offices along Pulehu Road?	Yes, we can check on that.

RECEIVED FROM	DATE	QUESTION/COMMENT	RESPONSES
Cultural Stakeholders (10) See sign-in Sheet	2/26/2020	So you folks still need to plan other generation projects like solar, wind?	Yes, the Stage 2 RFP is asking for both variable renewable generation as well as batteries
		So Hawaiian Electric is not planning to propose solar or wind projects?	The RFP is soliciting these resources, but the self-build team is only submitting proposals for standalone energy storage projects.
		In the RFP, there are multiple things you can propose. Are there other bidders who are proposing battery projects?	We are not aware of what the other developers are proposing
		If Hawaiian Electric is not selected and KPP needs to be retired, would that still happen (KPP's retirement).	Yes, regardless of which projects are selected, the KPP retirement would still happen
		No matter who wins the bid, Hawaiian Electric still owns the poles and wires, so they will still need you to distribute the power.	Yes, the transmission and distribution infrastructure is still the company's and will remain so. The developers for selected projects would be responsible for the connection to the system, but the distribution of the energy is still with the Company regardlesss who wins.
		Maui lassoed the sun. My concern is outside entities coming in to sell power to us. Example, Mahi Pono has partners not even from the continent. We need to be sustainable because we are not connected to the mainland, that's a good thing. We should not be feeding energy to other islands (O'ahu). My concern is outside entities coming in. We are stakeholders of the natural resources - Sun, wind, water.	Yes, there could be developers from outside of Hawaii.
		Concerned about the process selling us out, bidding us out.	The bidding process is intended to make sure the company is getting the best value for our customers by getting various proposals. The Company will make sure the developers are responsible and are held to their contract.
		Why didn't Hawaiian Electric bid into Phase I of the RFP process?	The company was not allowed to participate in the Phase 1 RFP.
		If Hawaiian Electric bids into the process, guaranteed the cost would go up because it's very costly to start up projects.	The selection team of the Company RFP team will ensure that the selected projects bring the best value to the customer.
		Define renewable energy.	Any energy that can be created from renewable resources like wind, sun and water that could be transformed into energy that can be distributed to customers
		Is it specifically 40 MW?	The RFP requested 40 MW for a 4 hour period of time.
		Does the company have any plans to retire the other power plants?	We are not aware of any plans for retirement of other plants.

RECEIVED FROM	DATE	QUESTION/COMMENT	RESPONSES
		It gets more expensive as you go along, right? That last 5% will be the most expensive?	It is too early to predict the costs of the last 5% of our transition to renewable energy. We hope that through the process of competitive bidding the costs will be managed.
		Will you be removing the structure (KPP). It would be prudent to try to restore the area, maybe not to its original state, but something close to it.	The self-build team is not aware of plans to remove the structures at KPP.
		You're planning for the replacement of KPP, but not for decommissioning it.	The Company plans to cease operation of KPP. Whether it will be completely decommissioned has yet to be determined.
		Concerned about sea level rise and infrastructure close to the coastline.	As part of the RFP, the requirements for site selection noted it had to be out of any flood zones. Our proposed site is well clear of the coastline and any area susceptible to sea level rise or flooding.
		What is the intent for future possible expansion?	We do not have have any plans for expansion of the project. The project design will include the capacity to add battery units as needed to maintain the system's capacity over the 20 years
		Will your project be adequate for future population and visitor growth?	That is a good question for our planning team, who developed the requirements for the RFP. As the self-build team, we are responding to the RFP requirements as they are stated.
		If KPP tapers off, Māʻalaea Power Plant is enough to sustain the entire island?	The Company's planning process indicates that if the amounts of capacity and energy solicited in the RFP process are installed, then the combination of existing resources, with the new resources, will meet the island's electrical needs.
		So this is for Central Maui only?	No, the project serves the entire island.
		Outside entities need to realize that we live on a tiny island in the middle of the Pacific Ocean, our resources are limited.	Yes, as we showed earlier, we are not able to connect to other grids like they do in the mainland, so our grid needs to be robust enough to remain independent.
		We have windfarms that are almost 20 years old. Are they going to be contributing power to this battery project?	Yes, all resources on the Maui grid could be feeding into the battery.
		There needs to be a lifecyle plan.	Yes, part of the RFP was a decommissionng plan outlining what happens at the end of the projects life
		Would hate to see the County have to pay to clean up someone else's mess.	Yes, the developers are all required to include cost and plans for decommissioning their project at the end of their contract

RECEIVED FROM	DATE	QUESTION/COMMENT	RESPONSES
		The company should allow more rooftop solar to help take the pressure off to provide 100% renewable energy.	Thank you for your feedback.
		AES solar farm in Central Maui, will they be installing a battery system to capture all or a percentage of the energy?	Yes, the AES Kuihelani project has an associated battery
		Is this battery project for stabilization?	Amongst other capabilities, it can provide voltage regulation and help with reliability of the system.
		This storage system, the Kahului Power Plant, the private solar and wind farms. All put together, are they tied into the grid distribution system?	Yes, all are tied to the grid to provide power to the island.
		Do we have skilled labor here to handle the operations?	Our Battery partner does have personnel in Hawaii that does maintenance and repairs. We are working with them to also train our own personnel to do maintenance on the intermittent years between the overhaul years 5, 10 and 15.
		A map of all current renewables would be good for the March meeting.	Yes, we will have something available.
		Any issues around noise?	The battery modules issue audible noise at the surface of the enclosure is 75dBA (comparable to vacuum cleaner). This will not be audible off the project site.
		Does it emit anything?	No emissions from the batteries once installed. As part of our PUC Application a Greenhouse Gas Analysis will be completed.
		How often do the cells have to replaced? Will you do that here?	For this project the design is to add battery modules as the cells lose their capacity. The design already includes the space for these additional modules.
		What is the life cycle of the battery?	The expected lifespan is 20 years
		When power goes to the battery and to the customer, are we going to pay for it?	For the proposed project, the cost to build and maintain the battery system for the 20 year life of the project is what will be included in customer bills.

RECEIVED FROM	DATE	QUESTION/COMMENT	RESPONSES
		By the time this is paid for, what year is that? Looking at it from a consumer's point of view. The pitch is always cost savings, lower bills. My bill has never gone down with the wind and solar farms that have come online. What's in it for the public? You're getting energy for free. All of these proposals are good for business, but what's in it for the public? When does it end? When do we get to see our bills go down for your harnessing our wind and sun? I want to see those projections. It comes out of our pocket for you guys to do business.	To meet the 100% renewable energy goal in 2045, equipment is needed to convert renewable energy such as sun and wind into electrical energy that can be used by the customers. As the rewable projects get selected the company will estimate the financial and system impacts and how that affects customers. Not relying on fossil fuel for energy will be a huge benefit to customers.
		With this storage system, will people be seeing an increase or decrease in their bills?	At this time we don't know the impacts of the projects on the customer's bills. Once all projects have been selected the company will assess the impacts to customers.
		Has there ever been a time in Maui Electric's history when the customer got a break in their bill?	We don't have that information.
		There needs to be a clause, the developer is responsible for maintenance and clean up, not the community, not Maui Electric. South side on the Big Island is a good example. Windmills were left to rust and deteriorate. That's a safety hazard. Our environment is harsh and salty. Ulupalakua is already having problems. We're not against this, but they have to take care of what they build.	Yes, all projects in the RFP are required to provide a decommissioning plan.
		I hate windfarms. They're ugly, they're hard to take down. Big Island, South Point, the windmills decimated that place.	Thanks for your feedback.
		What about saving the planet, I'd like to hear more about that in regards to this project.	This project, if selected, would be needed to reach our 100% renewable goal. In getting to the 100% renewable energy goal we will not be reliant on fossil fuel to provide energy.
		Is that site for batteries only?	Yes, the 1.8 acres offered in the RFP was only for batteries. There are 33 acres on other parts of the site that is reserved for other renewable energy resources.
		Are all the projects being proposed for the Waena site?	We are not aware of what the other developers are proposing
		Was the land always zoned industrial or was it zoned something else before?	Originally zoned agricultural before the Company purchased it, and it was then rezoned to industrial
		So other bidders who are proposing generation projects need to find their own land?	Other developers can use the land offered in the RFP or yes, they can find their own land to propose.

RECEIVED FROM	DATE	QUESTION/COMMENT	RESPONSES
		How safe did you make these new batteries? Batteries can catch on fire, chemicals can be in the smoke. Are you ready for that with a containment mechanism and to capture any chemicals? That's my biggest concern. I'm into renewables, but safety is my biggest concern.	The battery modules we are proposing have their own internal cooling system to maintain the temperature of the batteries. Also, we will have a fire containment system on-site should there be a fire. The battery modules proposed have been tested to resist thermal propagation or thermal runaway propagation which means if there is a fire within one module it will not spread to the next module over, it will remain in it's own unit.
		Will the batteries be safeguarded from fires that start elsewhere? There was a fire nearby last year.	*Yes, vegetation mangement and fire breaks will be in place to* manage fires from nearby sites.
		Would you have a containment system to capture any leakage of coolants? The automotive industry needs to have a double containment system.	The batteries themselves are dry-cell batteries and don't contain fluids that could leak. The battery modules are containerized to catch any fluids that may leak from the cooling system.
		Would be nice to have security systems in place, it would make the public feel better, safer.	Yes, the project will have a security system, and will tie into the adjacent substation's security systems.
		Seen flo-batteries in San Francisco, they had containment systems.	Flow batteries have large volumes of fluid that would need to be contained. Our proposed batteries are dry-cell units.
		Will you have on-site employees?	No personnel will be on-site during normal operation. Everything will be operated remotely. Personnel will visit the site for maintenance.
		Are you making it bullet-proof? This area is prime hunting area. A bullet can travel for miles.	We had not considered that but will check with our battery partner.
Environmental Stakeholders (8) See sign-in sheet	2/26/2020	How difficult is it going to be for Oahu to reach the 100% energy goal?	It will be challenging but we're putting things in place to meet the goal.
		When you say "Self-build" do you mean that Maui Electric will submit is own bid for a project and compete against other developers?	Yes, self-build means that we are putting in proposals on the Company's behalf.
		Do you do the self-build work on company time or personal time?	The self-build team is a company group and work is done during the work day. It is part of our job.
		Communities will want to know how many bidders made the short list.	The self-build team is like any other developer and will not be privy to that information
		Who's on the selection committee?	The RFP team which is made up of various groups within the company including executives. As well as the independent observer who is selected by the PUC. No self-build team members have that information.
		Having transparency is important.	Thanks for your feedback.

RECEIVED FROM	DATE	QUESTION/COMMENT	RESPONSES
		So the self-build team is embedded in the company's regular course of business?	The self-build team is made up of company personnel, and is stood up when a RFP is issued that we can participate in as a bidder. There is a firewall between the Self-build team and members of the RFP team. There will be no cross-communication with any members on either side.
		Would the teams stay the same under a new RFP or would there be changes?	The self-build team will most likely stay the same. The code of conduct includes rules regarding personnel changes.
		So you're building the whole 40 MW part of the RFP?	Yes, we will be proposing the whole 40MW of energy storage requested in the RFP.
		So HECO's going to build a substation either way?	Yes, in order to satisfy the transmission planning criteria for system reliability, the substation will be needed regardless of whether a battery system is installed at Waena.
		Is this Pu`unene?	No, central Maui across from the Central Maui Landfill.
		How does the RFP committee evaluate a grid-tied battery against a stand-alone?	To clarify, a standalone battery is grid-tied. The other type of storage would be one tied to a renewable energy source, like a PV farm or wind farm.
		So your project is just for storage?	Yes, our project is just energy storage and does not include any renewable energy production resources.
		Does the RFP specify the specs of the substation?	No specifications for the substation were provided in the RFP as that is a separate project
		The outreach process is faulty by design. The "community" doesn't have the expertise to ask the right questions. One bidder who presented to the Kula Community Association is proposing to build closer to Kaupō, so they should be talking to that community.	Thanks for your feedback. Our process for community outreach is always working to improve.
		Glad to hear that there are no new additional power lines.	Thanks for your feedback.
		This amount of energy storage doesn't seem like enough to get us through times of emergency, it doesn't seem to meet our needs.	The proposed project is only one aspect of the Company's reliability portfolio, and is not intended to meet all of the island's needs. The intent of this project is to meet the capacity requirement of the RFP, in order to allow KPP to be retired
		What type of batteries are you going to be installing?	Lithium-ion dry cell
		What is dry cell?	There are no liquids in the chemistry, it is made up of dry cell electrochemical cells instead, no concern of spillage
		Would the battery take power only from utility scale solar and wind or also from distributed solar?	The battery will be charged off the grid which is a mix of all the resources on the grid.

RECEIVED FROM	DATE	QUESTION/COMMENT	RESPONSES
		How much power would the battery provide?	40MW
		What's the lifetime of these batteries and what is your plan for its end of life?	The project will be in service for 20 years and a decommissioning Plan is included in our proposal.
		So after 20 years you'll have to build a new battery system?	Not necessarily, it all depends on the needs of the community and grid at the end of the project's useful life.
		So the vendor will be responsible for recycling?	Yes, our battery vendor has a robust recycling process that uses recyling metals from the existing batteries.
		Are there any known cultural resources or practices that are known from this site?	During our initial assessment we did not find anything of significance.
		Many projects require an EIS, how does that fit into your timeline?	An EIS was performed on the site when we initially purchased the land. Based on our intended use for the site, an EIS is not called for.
		Requesting the FLED lighting to minimize seabird interactions.	Our company standard is to use lights that minimize seabird interactions.
		The requirement is that the battery must be on the same property as the substation or very close?	Yes, the requirement is to interconnect direclty into a substation.
		Did they define what "close" is?	Our project is immediately adjacent the Waena Switchyard site
		When you refer to industrial zoning, is that part of the larger community plan just that site?	It's industrial zone is only for that site. The surrounding land is agricultural
		What are you doing with the other 63 acres?	There are requiremenst of the zoning that we provide 33 acres of renewable resources if the land is used, but there are currently no other plans at the site besides the Batteries and Switchyard
		Was the land zoned agriculture before it became industrial?	Yes
		What's the likelihood of a Kahuku-type fire happening here?	Not very likely due to the battery's cooling system and robust testing. There will be plans with local jurisdictions to handle any issues.
		What's your fire prevention plan?	We will have a fire suppression system, fire breaks and vegetation management to manage any fire concerns. Also we will be dealing with local authorities on plans for how we will deal with these issues.
		The Maui Fire Task Force is working on federal grant sources for fire prevention, that might be a good resource for Hawaiian Electric.	Thanks, we will consider that.
		The cheapest batteries have the highest risk for runaway fire.	Thanks for your feedback.

RECEIVED FROM	DATE	QUESTION/COMMENT	RESPONSES
Stakeholder	3/30/2020	Do you know what's going to happen to the existing Kahului Power Plant?	At this time we are only aware of the plan to cease operations at KPP
		Why only 40 MW, looks like there's more room on the site to do more.	The 40 MW was the size identified in the RFP as the need on Maui
		You can buy part of a grid somewhere, right? (CBRE) This would allow more participation from people to add to the grid, so this kind of adds to this project.	The proposed battery should allow for the integration of more renewable energy resources by allowing energy to be stored instead of curtailed.
		I'm assuming there are going to be other bidders and you don't know what they're proposing, right?	Yes, we are not aware of other developer's projects
		When is the first round of comments?	We are currently taking all comments for the project on our website and at our mauibess@hawaiianelectric.com.
		Do the batteries work as well as a solar field?	Batteries do not generate electricity like a solar system does, they store energy and deliver it when needed. Batteries are able to store the energy from a solar facility (or other sources of power) and then deliver it to customers during all times of the day in any weather
		How are the batteries recycled? Sometimes things can go bad before the end of their useful life and have to changed out.	Yes, part of the operations cost is to augment or add battery modules as batteries lose their capacity
		The batteries are less intrusive than a solar field.	Thanks for your feedback.
		Visual impact is low, that's good.	Thanks for your feedback.
		I don't know how the location could be better.	Thanks for your feedback.
		Interesting that it's Hawaiian Electric's land and it was offered to all bidders.	Yes, the PUC felt that any land the company had available should be made available to all bidders
Stakeholder	3/31/2020	Employees may be concerned about emissions.	Thanks for your feedback.
		I'm okay with all of the fire-related aspects, but not sure how batteries really work.	These batteries will be similar to the lithium-ion batteries in your computer. They store energy from the grid and when it's needed, it will be dispatched for use by customers.
		Pulehu Road backs up a lot, especially on holidays, weekends, and mornings. This is more of a concern for your project than our landfill.	During construction, we will try to schedule deliveries or any traffic times during off-peak hours.
		County will be installing a left turn lane into the landfill. Project is approved and will be commencing any time after July 1. To be completed by the end of December 2021.	Thanks for that information.

RECEIVED FROM	DATE	QUESTION/COMMENT	RESPONSES
MauiBESS email	4/2/2020	I am in favor of adding battery storage to our electric grid on Maui (as well as the other islands). This is an important step towards shifting to the use of more environmentally responsible energy with greater reliability.	Thanks for your feedback.
MauiBESS email	4/3/2020	SFPE Webinar: How to Detect Potential Thermal Runaway in Lithium-Ion Batteries	The system will be monitored by our system operations and will note any increased temperatures.
MauiBESS email	4/8/2020	How does this project's capacity compare to the load on Maui, both daytime and nighttime?	This project could deliver approximately 20% of Maui's peak (evening) demand, for up to four hours.
MauiBESS email	4/8/2020	Any consideration of the brush fires so prevalent in the area?	Yes, Thermal breaks and a fire suppression system will be included in the design to minimize affects of brush fires
MauiBESS email	4/8/2020	How many stand-alone battery systems like this has MECO developed? If any, what size and where?	Currently there are no MECO-developed utiliy scale batteries on the Maui system designed for this purpose. Our selected battery partner has extensive and global experience installing projects like the one proposed.
MauiBESS email	4/8/2020	How does the 160MWh battery capacity proposed for this project compare to the total overnight (6pm to 6am) demand for electricity on the island of Maui?	This is a question better posed to the RFP team or the Company's planning team. As the self-build team, we are responding to the requirements identified in the RFP.
MauiBESS email	4/8/2020	Would this battery project create new grid capacity for additional rooftop solar without batteries?	This is a question better posed to the RFP team or the Company's planning team. As the self-build team, we are responding to the requirements identified in the RFP.
MauiBESS email	4/8/2020	What is the estimated life cycle for this battery project?	The project is expected to have a 20 year life span.
MauiBESS email	4/8/2020	How was the 40/160 size ultimately determined as the optimum size for Maui?	The company planning department determined the size for the project
Facebook Live Comment	4/8/2020	How much above sea level is this site? It's very windy there. Do you guarantee no salt or water erosion from air vapor?	357 ft above sea level. The battery enclosures are resistant to corrosion.
Facebook Live Comment	4/8/2020	How do you dispose of those batteries?	Our battery vendor has a robust recycle program. They take the metals from the batteries being recycled and reuse them in their products.
Facebook Live Comment	4/8/2020	How much power can be stored and if it were needed in an emergency, how long could it keep our island powered? What happens after 20 years?	40 MW can be discharged for up to 4 hours, which is not intended to be adequate to provide all the power that Maui needs. A decommissioning plan was included in our proposal which includes utilizing our battery partner's recycling program.
Facebook Live Comment	4/8/2020	Where is that "recycling facility" dead batteries go to? Is it off island? Out of state?	It is in Nevada

RECEIVED FROM	DATE	QUESTION/COMMENT	RESPONSES
Facebook Live Comment	4/8/2020	Have you considered vertical stacking of batteries so the footprint is even less?	Yes but that would be harder to maintain as infrastructure would need to be built to accommodate the higher heights of the batteries. It would be less expensive to build and maintain on one level.
Facebook Live Comment	4/8/2020	Is it protected against Cat. 5 hurricanes?	Yes, the modules can withstand up to 157 mph
Sent via WebEx Chat	4/8/2020	What are the daytime loads currently?	Daytime loads vary, but are typically between 50 and 100 MW on Maui.
Sent via WebEx Chat	4/8/2020	How will this system be financed? Will MECO be issuing a preferred investment option to the local community for financing (and then owning) this system?	If selected, this project will be financed by the Company as part of our larger capital project portfolio, using a mix of debt and equity. It will not be available to individual investors except through stock purchases in our parent company, HEI.
Sent via WebEx Chat	4/8/2020	What's the cost and payback on the system?	We are currently not able to provide financial information until all the projects have been selected
Sent via WebEx Chat	4/8/2020	What happens to the batteries at end of life?	They will be recycled with our battery vendor's process. Battery modules will be sent back to the manufacturer to recycle the metals in the batteries
Sent via WebEx Chat	4/8/2020	Why not 2-way EV charging instead? With specific response to EV cost and emissions savings models + local ownership transfer we've developed (++ consideration of investment in as-available solar powered EV charging stations)	At this time, the technology for 2-way EV charging is not adequately developed, and the amount of EV's needed to meet the 40MW requirement are not available on Maui.
Sent via WebEx Chat	4/8/2020	Has Maui Electric considered gravity pump storage instead of battery storage? What did the findings show?	The company has considered a range of energy storage technologies, and based on a variety of factors, considers this technology to be the best value for our customers at this time.
Sent via WebEx Chat	4/8/2020	How will this affect grid capacity, net metering capacity, and ratepayer rates?	This is a question better posed to the RFP team or the Company's planning team. As the self-build team, we are responding to the requirements identified in the RFP.
Sent via WebEx Chat	4/8/2020	Should this project be a proposed part of the Common Bond portfolio?	If selected, financing decisions for this project will be made based on conditions at the time.
MauiBESS email	4/8/2020	What other sources of firm power will be utilized to replace the firm power produced by Kahului Power Plant? It doesn't seem this BESS project will adequately replace the firm capacity of Kahului Power Plant.	The Company's planning process indicates that if the amounts of capacity and energy solicited in the RFP process are installed, then the combination of existing resources, with the new resources, will meet the island's electrical needs.

RECEIVED FROM	DATE	QUESTION/COMMENT	RESPONSES
WebEx	5/1/2020	How many MegaWatt hours is 40 MWs?	Megawatt-hours is a measure of the amount of energy that a system can deliver. In the case of our project, it will be capable of delivering up to 40 megawatts of power, for up to 4 hours. This amount of energy is 40MW x 4 hours, or 160 megawatt-hours.
WebEx	5/1/2020	Have you found a water source for the fire suppression system? Mahi Pono has pressurized water systems in the area if the utility is interested.	We will discuss with them that possibility. Currently the water needs were to be a tank on site.
WebEx	5/1/2020	Mahi Pono has requested a dedicated 69 kV line to come off of the new substation, hopefully that's still in the plans.	The self-build team is not part of that discussion.
WebEx	5/1/2020	Sounds like a great project that everybody can benefit from.	Thanks for your feedback.

Hawaiian Electric Company, Inc. hereby identifies redacted confidential information that will be submitted confidentially upon issuance of a Protective Order in this proceeding. This log (1) identifies, in reasonable detail, the confidential information's source, character, and location; (2) states clearly the basis for the claim of confidentiality; and (3) describes, with particularity, the cognizable harm to the producing party or participant from any misuse or unpermitted disclosure of the information.

Reference	Identification of Item	Basis of Confidentiality	Harm
Exhibit 2	Project Cost Summary	Confidential cost and financial information which falls under the frustration of legitimate government function exception of the Uniform Information Practices Act ("UIPA").[1]	Disclosure of the confidential information to the general public could disadvantage and competitively harm the Company, impact the Company's bargaining power relative to other vendors, place the Company at a competitive disadvantage in future proposals and contract negotiations, and harm the Company's relationships with existing and/or prospective vendors and/or customers. Moreover, disclosure of the confidential information could result in the Company paying increased amounts for the same products and services in the future, which would increase costs for the Company and its customers. In addition, public disclosure of this information may discourage vendors from doing business with the Company, discourage vendors from making confidential disclosures to the Company, and expose the Company to certain liabilities. Further, public disclosure of the confidential information would provide a roadmap, enabling competitors to not provide their best price in response to subsequent RFP's, but rather a price at or slightly below what is offered by Company. The Company contends that disclosure of the information will not only harm the Company competitively, but also have an adverse impact on subsequent RFPs.

[1] Haw. Rev. Stat. § 92F-13(3)

Reference	Identification of Item	Basis of Confidentiality	Harm
Exhibit 3, tabs 1 – 3 and 5 - 12	BESS MPIR Model	Confidential cost and financial information which falls under the frustration of legitimate government function exception of the Uniform Information Practices Act ("UIPA").[2]	Exhibit 3 reflects confidential cost information and methodologies, the disclosure of which to the general public could disadvantage and competitively harm the Company, impact the Company's bargaining power relative to other vendors, place the Company at a competitive disadvantage in future proposals and contract negotiations, and harm the Company's relationships with existing and/or prospective vendors and/or customers. Moreover, disclosure of the confidential information could result in the Company paying increased amounts for the same products and services in the future, which would increase costs for the Company and its customers. In addition, public disclosure of this information may discourage vendors from doing business with the Company, discourage vendors from making confidential disclosures to the Company, and expose the Company to certain liabilities. Further, public disclosure of the confidential information would provide a roadmap, enabling competitors to not provide their best price in response to subsequent RFP's, but rather a price at or slightly below what is offered by Company. The Company contends that disclosure of the information will not only harm the Company competitively, but also have an adverse impact on subsequent RFPs.

[2] Haw. Rev. Stat. § 92F-13(3)

Reference	Identification of Item	Basis of Confidentiality	Harm
Exhibit 5, tabs 1 - 4, 6, and 7	Revenue Requirements and Bill Impact	Confidential cost and financial information which falls under the frustration of legitimate government function exception of the Uniform Information Practices Act ("UIPA").[3]	Exhibit 5 reflects confidential cost information and methodologies, the disclosure of which to the general public could disadvantage and competitively harm the Company, impact the Company's bargaining power relative to other vendors, place the Company at a competitive disadvantage in future proposals and contract negotiations, and harm the Company's relationships with existing and/or prospective vendors and/or customers. Moreover, disclosure of the confidential information could result in the Company paying increased amounts for the same products and services in the future, which would increase costs for the Company and its customers. In addition, public disclosure of this information may discourage vendors from doing business with the Company, discourage vendors from making confidential disclosures to the Company, and expose the Company to certain liabilities. Further, public disclosure of the confidential information would provide a roadmap, enabling competitors to not provide their best price in response to subsequent RFP's, but rather a price at or slightly below what is offered by Company. The Company contends that disclosure of the information will not only harm the Company competitively, but also have an adverse impact on subsequent RFPs.

[3] Haw. Rev. Stat. § 92F-13(3)

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAIʻI

In the Matter of the Application of .MAUI ELECTRIC COMPANY, LTD. For Approval to Commit Funds in Excess of $2,500,000 for the Purchase and Installation of Item P0003267, Waena Battery Energy Storage System Project, and to Recover Costs through the Major Project Interim Recovery Adjustment Mechanism.	DOCKET NO.

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing Application, Verification and Exhibits 1- 9, together with this Certificate of Service, was duly served on the following party by electronic mail service as set for below:[1]

Division of Consumer Advocacy
Department of Commerce and Consumer Affairs
335 Merchant Street, Room 326
Honolulu, Hawaiʻi 96813
dnishina@dcca.hawaii.gov
consumeradvocate@dcca.hawaii.gov

DATED: Honolulu, Hawaiʻi, September 8, 2020.

HAWAIIAN ELECTRIC COMPANY, INC.

/s/ Richard VanDrunen

Richard VanDrunen
Regulatory Affairs

[1] As stated in Order No. 37043 *Setting Forth Public Utilities Commission Emergency Filing and Service Procedures related to COVID-19* (non-docketed), issued on March 13, 2020 at 11: Service of all documents filed by any parties, participants, utilities, stakeholders and/or other entities or individuals shall be via email. All entities making filings before the commission will be required to supply an email address that can be used for service. Any Certificates of Service for docketed or other matters that previously had listed the entity's name and the physical address where a document was served via first-class mail, shall instead reflect the entity's representative's name, entity name, email address where served, as well as the date of service.