BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAI'I

In the Matter of the Application of

HAWAIIAN ELECTRIC COMPANY, INC.
HAWAI'I ELECTRIC LIGHT COMPANY, INC.
MAUI ELECTRIC COMPANY, LIMITED

For approval to commit funds in excess of $2,500,000 for the ADMS Component of the Phase 2 Grid Modernization Project, to Defer Certain Computer Software Development Costs, to Recover the Capital, Deferred, and the Operations and Expense Costs through the Major Project Interim Recovery, and Related Requests.

DOCKET NO. 2019-0327

<u>APPLICATION OF</u>
<u>HAWAIIAN ELECTRIC COMPANY, INC.,</u>
<u>HAWAI'I ELECTRIC LIGHT COMPANY, INC. AND</u>
<u>MAUI ELECTRIC COMPANY, LIMITED</u>

<u>VERIFICATION</u>

<u>EXHIBITS "A"–"K"</u>

<u>AND</u>

<u>CERTIFICATE OF SERVICE</u>

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

Vice President
Hawai'i Electric Light Company, Inc.
Maui Electric Company, Limited

P. O. Box 2750
Honolulu, Hawai'i 96840

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APPLICATION

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

By this Application, Hawaiian Electric Company, Inc. ("Hawaiian Electric"), Hawaiʻi Electric Light Company, Inc. ("Hawaiʻi Electric Light") and Maui Electric Company, Limited ("Maui Electric") respectfully request the approvals necessary to commence and obtain cost recovery for the Advanced Distribution Management System ("ADMS") component, herein referred to as the Project ("Project"), of the second phase ("Phase 2") of their Grid Modernization Strategy[1] implementation.[2]

[1] See "Modernizing Hawaii's Grid For Our Customers," filed in Docket No. 2017-0226 on August 29, 2017 ("GMS," "Grid Modernization Strategy," or "Strategy").

[2] Hawaiian Electric, Hawaiʻi Electric Light and Maui Electric are collectively referred to as the "Hawaiian Electric Companies" or "the Companies."

I. EXECUTIVE SUMMARY

Managing the Hawaiian Electric Companies' current and future electrical grid requires new systems in the control room to facilitate existing reliable and optimized integration of distributed, variable, and renewable resources. Increasing levels of these resources have a substantial impact on both the distribution system and the bulk grid, and the lack of visibility into and control over such a major component of the total grid energy is unsustainable. As the Commission has recognized, a modernized grid is the "backbone" necessary to advance the State's Renewable Portfolio Standards ("RPS") goals, support integration of additional levels of renewables, encourage competition, empower consumers to make their own choices concerning the level and types of electric service they desire, and leverage customer-sited resources to assist in grid operation.

Implementation of the ADMS component of Phase 2 of the Companies' Grid Modernization Strategy ("GMS") is an integral next step in the Companies' pursuit of the GMS guiding principles of maintaining and enhancing the safety, interoperability, security, reliability, and resiliency of the electric grid, at fair and reasonable costs, while at the same time ensuring optimized utilization of resources and electricity grid assets to minimize total system costs for the benefit of all customers. Consistent with these principles and in accordance continued stakeholder feedback, the ADMS Project is focused on: (1) integrating greater renewable energy, specifically DER, and empowering customer energy options and (2) establishing an interoperable, standards-based system that will work with present and future components of the Companies' systems. Building upon the GMS investments made to date, the ADMS will serve as one of the foundational tools for providing distribution system operators a new way to manage the grid, transitioning from operating system-level devices toward enhanced visibility and

control to understand the increasingly complex and abundant paths of electricity flow at the distribution level.

The Companies' ADMS Project entails a deployment and integration of a commercially available ADMS software solution for all three operating Companies. The enhanced capabilities enabled by the ADMS will result in numerous customer benefits, including:

- Enabling customer energy options and advancing clean energy goals by providing operational visibility, monitoring, analytics, control, coordination, and automation to facilitate the safe and reliable operation of an electric grid with greater levels of distributed, variable, and renewable generation;
- Improving system reliability and communications by enhancing the ability of the control room to identify the locations and causes of faults, prioritizing outages based on customers affected, and optimizing the dispatch of field technicians; and
- Enhancing operational resiliency and efficiency by allowing operators to analyze distribution grid-edge voltage support and to short-circuit current availability, heightening situational awareness, assisting in restoration triage, and providing a platform that can be used to integrate grid-tied storage batteries and local microgrids.

The Companies plan to deploy the ADMS over a four-year period through three releases, with each release layering additional capabilities and more sophisticated controls while maintaining cybersecurity. The Companies estimate the total capital, deferred, and operations and maintenance ("O&M") costs of the Project through implementation to be $45.8 million, and they will seek to recover these costs through the Major Project Interim Recovery ("MPIR") adjustment mechanism until base rates that reflect these costs take effect in a future rate proceeding. For residential customers with typical energy usage, the costs of the Project will translate to average monthly bill impacts of $0.24, $0.76, and $0.72 at Hawaiian Electric, Maui Electric, and Hawai'i Electric Light, respectively.

In order to maximize customer value, the Companies are employing a sequenced "walk-jog-run" approach to grid modernization. Additional capabilities will be required to execute the

vision articulated in the GMS, including the installation of distribution grid field devices (including remote intelligent switches, remote fault indicators, secondary var controllers, and line sensors) as a future component of Phase 2. The Companies are continuing to refine their deployment plan and needs for the field devices. They currently anticipate filing a separate application for the field devices component of Phase 2 in the second half of 2020.

II. REQUESTED APPROVALS

The Hawaiian Electric Companies respectfully request a decision and order approving:

(1) Implementation of the proposed Project (at a total current estimated cost of $45.8 million), as further described in Exhibit G (*GMS Phase 2 ADMS Project Costs*);

(2) A commitment of funds in excess of $2.5 million for the capital costs of the Project (currently estimated at [redacted], net of customer contributions) ("Capital Costs") pursuant to Paragraph 2.3(g)(2) of the Commission's General Order No. 7, as modified by Decision and Order No. 21002, filed May 27, 2004, in Docket No. 03-0257 ("G.O. 7");

(3) The proposed accounting and ratemaking treatment for the Project, as further described in Exhibit C (*Accounting and Ratemaking Treatment*), including:

(a) Deferral of the software costs of the Project (currently estimated at [redacted]) ("Deferred Costs") pursuant to the Companies' policy for *Accounting for the Costs of Computer Software Developed or Obtained for Internal Use* ("Software Accounting Policy") and Decision and Order No. 18365, filed February 8, 2001, in Docket No. 99-0207 ("D&O 18365");

(b) Accrual of an allowance for funds used during construction ("AFUDC"), as appropriate, while the software is under development for the Project, with a carrying cost equivalent to the AFUDC rate would be applied to the deferred costs after the software is in use until the deferred costs are included in rate base in determining rates;

(c) Recovery of the Capital Costs and Deferred Costs through the Major Project Interim Recovery ("MPIR") adjustment mechanism established in Order No. 34514, filed April 27, 2017, in Docket No. 2013-0141 ("Order 34514"),[3] until base rates that reflect the revenue requirements associated with the Capital Costs and Deferred Costs of the Project take effect in a future rate case for each respective Company, provided however that if the Commission is not inclined to allow the Companies to recover the Deferred Costs through the MPIR adjustment mechanism, then in the alternative, the Companies request approval to recover the Deferred Costs, with a carrying cost equivalent to the AFUDC rate applied, through a future rate case for each respective Company, with these deferred costs being amortized over 12 years, beginning when such amortization is included in rates, and the unamortized deferred costs are included in rate base; and

[3] The Commission's Major Project Interim Recovery ("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 (Decoupling Reexamination).

(4) Recovery of Operations and Maintenance ("O&M") costs as further described in Exhibit C (*Accounting and Ratemaking Treatment*), including:

(a) Deferral of the O&M costs incurred during the Project implementation (currently estimated at [redacted]); and

(b) Deferral of the annual, incremental post-implementation O&M costs (currently estimated at [redacted] annually) with recovery through the MPIR adjustment mechanism, until base rates that reflect the O&M costs of the Project take effect in a future rate case for each respective Company, provided however, that if the Commission is not inclined to allow the Companies to recover the O&M costs through the MPIR adjustment mechanism, then in the alternative, the Companies request approval to defer and recover the O&M costs, with a carrying cost equivalent to the AFUDC rate applied, through a future rate case for each respective company, with the Deferred Costs being amortized over 12 years, beginning when such amortization is included in rates, and the unamortized deferred costs are included in rate base;

(5) Deferral treatment of O&M costs incurred prior to Commission approval; including recovery of the deferred O&M costs (currently estimated at [redacted]) through the MPIR adjustment mechanism, until base rates that reflect the O&M costs of the Project take effect in a future rate case for each respective Company, provided however that if the Commission is not inclined to allow the Companies to recover the O&M costs through the MPIR adjustment mechanism, then in the alternative, the Companies request approval to recover the deferred O&M costs,

with a carrying cost equivalent to the AFUDC rate applied, through a future rate case for each respective company, with the Deferred Costs being amortized over 12 years, beginning when such amortization is included in rates, and the unamortized deferred costs are included in rate base; and

(6) Such other and further relief as may be just and equitable in the premises.

III. APPLICANTS

Hawaiian Electric, whose principal place of business and whose executive offices are located at 1001 Bishop Street, Suite 2500, Honolulu, Hawai‘i, is a corporation duly organized under the laws of the Kingdom of Hawai‘i on or about October 13, 1891, and now exists under and by virtue of the laws of the state of Hawai‘i. Hawaiian Electric is an operating public utility engaged in the production, purchase, transmission, distribution, and sale of electricity on the island of O‘ahu.

Hawai‘i Electric Light, whose principal place of business and whose executive offices are located at 1200 Kilauea Avenue, Hilo, Hawai‘i, is a corporation duly organized under the laws of the Republic of Hawai‘i on or about December 5, 1894, and now exists under and by virtue of the laws of the state of Hawai‘i. Hawai‘i Electric Light is an operating public utility engaged in the production, purchase, transmission, distribution, and sale of electricity on the island of Hawai‘i.

Maui Electric, whose principal place of business and whose executive offices are located at 210 Kamehameha Avenue, Kahului, Maui, Hawai‘i, is a corporation duly organized under the laws of the Territory of Hawai‘i on or about April 28, 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; the production, transmission, distribution, and sale of electricity on the island of Moloka‘i; and the production, purchase, distribution, and sale of electricity on the island of Lana‘i.

IV. CORRESPONDENCE

Correspondence and communications with regard to this Application should be addressed to:

Kevin M. Katsura
Director, Regulatory Non-Rate Proceedings
Hawaiian Electric Company, Inc.
P. O. Box 2750
Honolulu, Hawai‘i 96840-0001

V. STATUTORY PROVISION OR AUTHORITY

The approvals in this Application are requested pursuant to Sections 269-6, 269-7, 269-16, 269-94, and 269-95(1) of the Hawai‘i Revised Statutes (“HRS”), Sections 16-601-74 and 16-601-86 of the *Rules of Practice and Procedure Before the Public Utilities Commission*, Title 16, Chapter 601 of the Hawai‘i Administrative Rules, G.O. 7 Paragraph 2.3(g)(2), D&O 18365, Order No. 34514, and Decision and Order No. 35268 (“D&O 35368”), filed February 7, 2018, in Docket No. 2017-0226.

VI. EXHIBITS

The following exhibits are provided in support of this Application:

Exhibit A	–	Grid Modernization Strategy Working Plan
Exhibit B	–	GMS Phase 2 ADMS Project Justification with Business Case Support
Exhibit C	–	Accounting and Ratemaking Treatment
Exhibit D	–	Interim Recovery
Exhibit E	–	Request for Proposal
Exhibit F	–	GMS System Architecture and Cyber Security
Exhibit G	–	GMS Phase 2 ADMS Project Costs

Exhibit H – Bill Impact

Exhibit I – Hawaiian Electric Companies' Decoupling Calculation Workbook

Exhibit J – Glossary of Terms

Exhibit K – Confidentiality Justification

VII. GRID MODERNIZATION STRATEGY

This application comprises the next step in executing the Companies' Grid Modernization Strategy ("GMS"). This customer-centric Strategy provides near- and long-term plans for the Companies to deploy advanced technologies and back office systems that will integrate new customer-facing, grid-facing, and utility operations technologies and processes with the existing infrastructure to update the electric distribution grid, which, in turn, will pave the way for the Companies to achieve Hawai'i's 100% renewable portfolio standards ("RPS") goal by 2045, reduce greenhouse gas emissions ("GHG") and enable greater customer energy options.[4,5]

A. GMS BACKGROUND

On February 7, 2018, the Commission issued D&O 35368, finding that the GMS reasonably complies with the Commission's earlier directives, providing additional directives,

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[4] See Hawai'i State Energy Office, Grid Modernization, Renewable Portfolio Standard targets, available at http://energy hawaii.gov/renewable-energy/grid-modernization.

[5] Customer energy options include but are not limited to Demand Response ("DR") and Distributed Energy Resources ("DER") programs, Time-of-Use ("TOU") rates, and capabilities to provide customers insight to better manage their energy usage.

and ordering the Companies to implement their GMS in accordance with the Commission's directives.[6]

The Companies filed their GMS Phase 1 implementation application ("Phase 1 Application") in Docket No. 2018-0141 on June 21, 2018. The Phase 1 Application outlined the Companies' plans for: (1) advanced meter deployment to support enrollment in customer energy options, replacement meters, and new meter sets; (2) a meter data management system ("MDMS") to manage the advanced meters and meter data; and (3) the telecommunication field area network ("FAN") to provide communication to not only the advanced meters, but also distribution grid field devices, including remote intelligent switches, remote fault indicators, secondary var controllers ("SVCs"), and line sensors.

On March 25, 2019, the Commission issued Decision and Order No. 36230 ("D&O 36230") in Docket No. 2018-0141 approving, with conditions, the Companies' Phase 1 Application. D&O 36230 provided additional direction on future phases, established reporting requirements, and directed the Companies to develop an Advanced Rate Design Strategy ("ARDS") and a Data Access and Privacy Policy.

D&O 36230 advised the Companies to: (1) "maintain their focus on greater renewable energy and DER integration as they implement Phase 1, and develop the remaining implementation phases of the Strategy[,]"[7] and (2) "remain proactive to ensure interoperability between present and future components of the Strategy."[8] This GMS Phase 2 ADMS application is both focused and proactive in achieving the GMS's vision to enable greater levels of

[6] See D&O 35268 at 39-40.
[7] D&O 36230 at 18.
[8] D&O 36230 at 21.

distributed, variable, and renewable generation while continuing the Companies' commitment to safety, interoperability, and improving reliability. Exhibit F (*GMS System Architecture and Cyber Security*) illustrates the interoperability and dependency of the GMS Phase 2 ADMS with GMS Phase 1 investments as well as other systems, including SAP, and the geographic information system ("GIS").Pursuant to D&O 36230, the Hawaiian Electric Companies hosted a two-day workshop on customer data access and privacy on July 16 and 17, 2019. Stakeholders were able to review and comment on the draft Customer Data Access and Privacy Policy, received an overview of the features and security incorporated into the Green Button standard for Download My Data ("DMD") and Connect My Data ("CMD")[9], and also were provided a demonstration of the customer energy portal that will be implemented with the MDMS. The customer Data Access and Privacy Policy was filed in Docket No. 2018-0141 on September 25, 2019.

Also pursuant to D&O 36230, the Companies hosted a workshop on advanced rate design on July 15, 2019. In accordance with Decision and Order No. 36476 ("D&O 36476") issued on August 19, 2019, in Docket No. 2014-0192, which combined the Distributed Energy Resources ("DER") policies and Demand Response ("DR") program and policies dockets, the Advanced Rate Design Strategy ("ARDS") was filed in Docket Nos. 2018-0141 and 2019-0323 on September 25, 2019, and will continue be reviewed and developed in Docket No. 2015-0412.

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[9] The Green Button initiative is a standard developed for making meter usage data available to consumers and authorized third party providers. Green Button began in 2011 with a published standard for customer data access. The two different versions of Green Button are Download My Data, which enables download of historical usage, and Connect My Data, which provides automated metering data under Internet and authorization standards.

B. <u>GUIDING PRINCIPLES TO INFORM GRID MODERNIZATION</u>

In accordance with the Commission's directives in D&O 35268 and D&O 36230, and in response to the ongoing conversations with stakeholders held since the Companies began development of their GMS (including the Integrated Grid Planning ("IGP") stakeholder workshops),[10] the Companies are now moving forward with their application for the ADMS component of the GMS Phase 2 implementation. The Companies are dedicated to ensuring that their GMS-related project applications align with Commission- and Legislature-developed guiding principles.[11]

In D&O 36230, the Commission reiterated that:

> [A] modernized grid is the "backbone" necessary to advance the State's RPS goals, support integration of additional levels of renewables, encourage competition, empower consumers to make their own choices concerning the level and types of electric service they desire, and leverage customer-sited resources to assist in grid operation.[12]

It is essential that all customers appropriately benefit from any costs incurred to advance the State's policies and related grid modernization investments. As such, the Companies proposed adapting and expanding the Commission's interpretation of Hawai'i's legislative guiding principles to ensure alignment with customer and stakeholder interests, as well as with GMS implementation. These guiding principles are necessary to counsel and provide a framework for grid modernization decisions by the Companies while moving forward with

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[10] For more information regarding the Hawaiian Electric Companies' Integrated Grid Planning ("IGP") efforts, please visit https://www.hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning.
[11] See, e.g., HRS § 269-145.5(b).
[12] See D&O 36230 at 54.

customers and stakeholders to achieve Hawai‘i's RPS goals. As summarized in the GMS,[13] the Hawaiian Electric Companies' guiding principles to inform grid modernization are set forth below, and each guiding principle is associated with the supporting interrelated dockets impacting each and/or this GMS Phase 2 ADMS application:

- Enable greater customer engagement, empowerment, and options for utilizing and providing energy services:
  - Docket No. 2018-0141 (GMS Phase 1 deployment of advanced meters and an MDMS to support customers enrolling in DR and DER programs);
  - Docket No. 2015-0411 (Demand Response Management System ["DRMS"]) and Docket No. 2015-0412 (DR Program Portfolio Tariff Structure);
  - Docket No. 2014-0192 – (DER Policies, including exploration of TOU tariffs[14] and establishment of Smart Export and Controlled Customer Grid Supply ("CGS+") Programs);
  - Docket No. 2014-0135 (Green Infrastructure Loan Program); and
  - Docket Nos. 2019-0323 (Companies' DER Policies, including the ARDS);
- Maintain and enhance the safety, security, reliability, and resiliency of the electric grid, at fair and reasonable costs, consistent with the State's energy policy goals:
  - This is a primary aspect of this GMS Phase 2 ADMS application.
- Facilitate comprehensive, coordinated, transparent, and integrated grid planning across distribution, transmission, and resource planning:
  - Docket No. 2018-0165 (Integrated Grid Planning ["IGP"]);[15]
  - Docket No. 2014-0183 (Power Supply Improvement Plan ("PSIP");
- Move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies:

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[13] GMS at 2.
[14] See Docket No. 2014-0192, Order No. 33923, issued on September 16, 2016.
[15] See https://www.hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning

- Docket No. 2019-0178 (Competitive Bidding Process To Acquire Variable Renewable Dispatchable Generation Paired With Energy Storage For The Islands Of Moloka‘i And Lana‘i);
- Docket No. 2018-0135 (Electrification Of Transportation Strategic Roadmap), and Docket No. 2018-0422 (To Establish Schedule EV-Maui Electric Vehicle Fast Charging Service);
- Docket No. 2018-0195 (Community-Based Renewable Energy Program);
- Docket No. 2018-0163 (Establishment Of A Microgrid Services Tariff);
- Docket No. 2017-0352 (Competitive Bidding Process To Acquire Dispatchable And Renewable Generation); and
- Docket No. 2015-0412 (To Develop a DR Program Portfolio Tariff Structure);

- Ensure optimized utilization of resources and electricity grid assets to minimize total system costs for the benefit of all customers:
    - This is another primary aspect of this GMS Phase 2 ADMS application.
- Determine fair cost allocation and fair compensation for electric grid services and benefits provided to and by customers and other non-utility service providers:
    - Docket No. 2018-0088 (Performance-Based Regulation); and
    - Docket No. 2019-0323 (Companies' DER Policies, Including the ARDS).

Consistent with the guidance provided,[16] the ADMS is:

- Focused on integrating greater renewable energy to lower GHG emissions, specifically DER, and empowering customer energy options.; and
- An interoperable, standards-based system that will work with present and future components of the Companies' systems.

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[16] In D&O 36230, the Commission stated on page 18 that "The Companies must maintain their focus on greater renewable energy and DER integration as they implement Phase 1, and develop the remaining implementation phases of the Strategy[,]" and on page 21 that "The Companies must remain proactive to ensure interoperability between present and future components of the Strategy."

C. GMS PHASE 2 AND BUILDING ON THE PHASE 1 PLATFORM

As noted in the Phase 1 Application, the Companies are implementing the GMS in phases, as illustrated in Figure 1.[17]

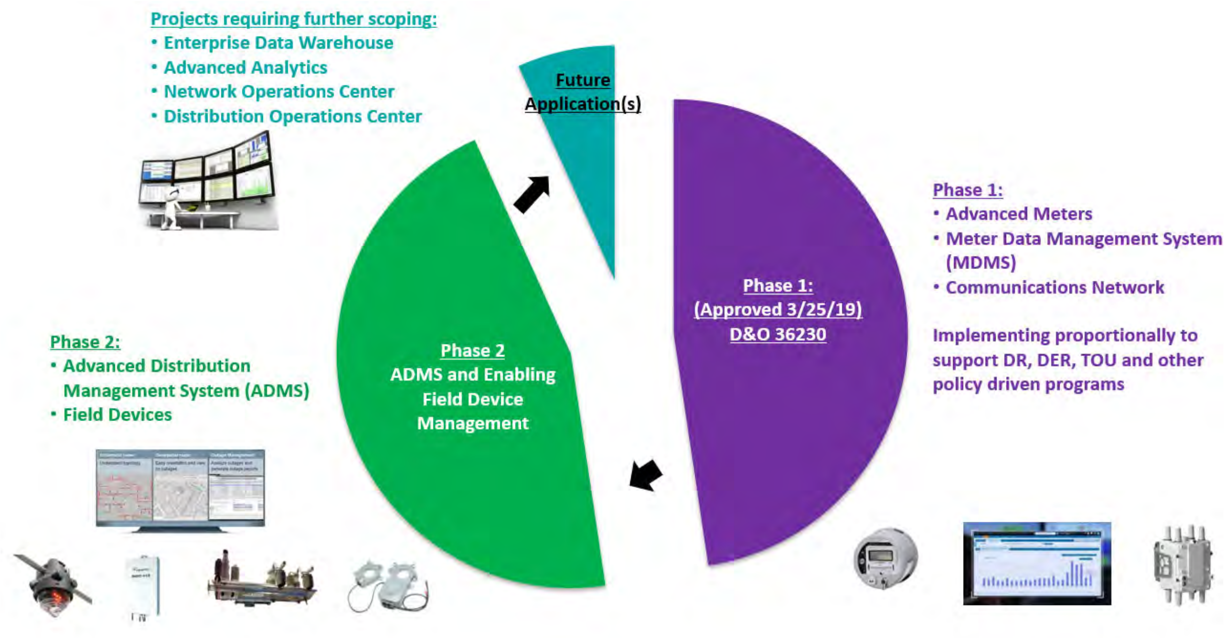

Figure 1

As detailed in Exhibit A (*Grid Modernization Strategy Working Plan*) of this Project Application, the overall GMS implementation for Phase 2 consists of an ADMS and distribution grid field devices, including remote intelligent switches, remote fault indicators, SVCs, and line sensors. As part of Phase 2, the ADMS will enable distribution system monitoring, control, and automation. In the case of voltage alerts from advanced meters, line sensors, or other distribution system sensing devices, an ADMS is a foundational component to assist distribution operators in understanding the context of an alert and identifying potential corrective actions.

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[17] See Docket 2018-0141, *Phase 1 Grid Modernization Project* Application at 18.

The Companies are ready to proceed with the ADMS, the details of which shall are described in this Application. However, the Companies are continuing to refine their deployment plan and needs for the field devices in order to maximize customer value. The Companies are employing a walk-jog-run approach, as this sequenced approach provides for a more prudent deployment that is cost-effective for customers. The ADMS is a significant change for operators that requires new procedures to operate and manage the distribution system.

The Companies are currently deploying limited amounts of field devices using existing budget processes and programs to address current needs for grid sensing and voltage controls that enables operators to gradually gain experience and prepare for the broader deployment of field devices. This phased strategy allows for the proper training and introduction to the capabilities offered by field devices so that operators are able to gain experience and proficiency prior to a broad rollout. Additionally, the timing for the deployment of these devices is being planned to coincide with the enabling capabilities provided in the sequenced releases of the ADMS, which are described in Exhibit B (*GMS Phase 2 ADMS Project Justification with Business Case Support*). Accordingly, the Companies are dividing implementation of Phase 2 into the instant Application for the ADMS and a subsequent, separate application for the field devices component of Phase 2. It is currently anticipated that the application for the field devices component of Phase 2 will be filed in the second half of 2020.

The GMS Phase 2 ADMS will build upon the GMS Phase 1 investment in advanced meters, MDMS, and a telecommunications network to continue to build the foundational platform required to progress toward a modern grid that has the ability to support customers' needs and the State's RPS goals. The Phase 1 GMS Platform implementation is focused on providing more granular customer data to empower customers to pursue energy options while

also providing more insight into the state of the distribution grid. The combination of advanced meters, FAN, and MDMS provide a foundational and empowering investment in the capabilities of the grid to meet the collective needs and expectations of customers, stakeholders, the Commission, and the Companies. Specifically, advanced meters will be deployed to customers enrolling in energy options such as DER and DR programs, where both interval meter data and more frequent meter reading are necessary to properly manage the parameters specified in the related tariff structures. In addition, the advanced meters will be the new standard meter for customer meter replacements as well as new construction. The Companies have begun to implement GMS Phase 1 in line with the Commission's directives in D&O 36230 and Order No. 36334 *Clarifying Decision And Order No. 36230* ("Order 36344"), filed on May 28, 2019, and are ready to pursue the ADMS in a sequential and logical order to build capabilities over time.

As detailed throughout this Application, the Project will provide the software system for operators, planners, and other systems to make the most of the data provided by distribution investments, including the advanced meters in Phase 1 and future field devices. The Project will ultimately enable additional distributed renewable energy by enabling more advanced, coordinated, and safe management of the grid as the Companies continue to increase the renewable energy portfolio and provide greater customer energy options.

However, the full capabilities of the ADMS cannot be executed without close integration with the other GMS components and the Companies' existing systems. The interrelation and support of these investments is further discussed in Exhibit A (*Grid Modernization Strategy Working Plan*) and Exhibit B (*GMS Phase 2 ADMS Project Justification with Business Case Support*), and also covered in Exhibit F (*GMS System Architecture and Cyber Security*).

D. RELATED PROGRAMS AND INITIATIVES

Since the time that the Companies filed their GMS as well as their IGP Workplan,[18] the number of interrelated dockets, programs, and proceedings has only increased. The related programs and activities include executing the Stage 2 dispatchable and renewable generation procurement,[19] executing a "soft launch" of non-wired alternative considerations,[20] implementing the Decentralized Energy Management System ("DEMS") while launching the customer energy option programs approved by the Commission,[21] exploring advanced rate design,[22] pursuing performance-based regulation,[23] and implementing the Phase 1 GMS deployment of advanced meters and FAN while installing an MDMS,[24] while simultaneously continuing to provide safe and reliable electric power for customers.

The Companies have also begun to execute their Integrated Grid Planning ("IGP") approach to harmonize the resource, transmission, and distribution planning processes by

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[18] See Docket No. 2018-0165, *Hawaiian Electric Companies' Integrated Grid Planning Report*, filed on July 13, 2018 ("IGP Report"). In addition, the Companies filed their IGP Workplan in Docket No. 2018-0165 on December 14, 2018. The Commission accepted the IGP Workplan via Order No. 36218 *Accepting the IGP Workplan and Providing Guidance*, issued on March 14, 2019.

[19] See Docket No. 2017-0352, *Hawaiian Electric Companies' Final Stage 2; Renewable, Battery Storage and Grid Services RFPs*, filed on August 22, 2019.

[20] See Integrated Grid Planning ("IGP") Distribution Planning & Grid Services Working Group https://www hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning/stakeholder-engagement/working-groups/distribution-planning-and-grid-services-documents

[21] See Docket No. 2015-0411, Application For Approval To Defer Certain Computer Software Development Costs For A Demand Response Management System, To Accumulate An Allowance For Funds Used During Construction, Etc., filed on December 30, 2015. The DEMS is the name of the product that was approved in the Demand Response Management System ("DRMS") docket.

[22] See Docket No. 2018-0141 - Advanced Rate Design Strategy; and Data Access & Privacy Policy, filed September 25, 2019, and Docket No. 2019-0323. Instituting A Proceeding To Investigate Distributed Energy Resource Policies Pertaining to the Hawaiian Electric Companies.

[23] See Docket No. 2018-0088, Instituting A Proceeding To Investigate Performance-Based Regulation, opened by the Commission on April, 18, 2018, via Decision and Order No. 35411.

[24] See Docket No. 2018-0141, Application For Approval To Commit Funds In Excess Of $2,500,000 For The Phase 1 Grid Modernization Project, To Defer Certain Computer Software Development Costs, Etc, filed on June 21, 2018.

integrating information and alternatives from all sources and levels.[25] Consistent with this methodology and the Commission's acceptance of the Companies' *PSIP Update Report: December 2016*,[26] the Companies' IGP provides a more detailed planning framework, the output of which will help identify future priorities for grid investment and modernization.

E. FUTURE PHASES, PROGRAMS, AND INITIATIVES

The ADMS builds upon the investments made to date, including those pursued in GMS Phase 1, but additional capabilities will be required to execute the vision articulated in the GMS. While the combination of advanced meters and ADMS provide the Companies' grid operators, engineers, and planners with more granular customer data and the software tools to make sense of that data, the Companies still need to make investments in the flexibility of the grid and the field assets to execute the actions identified by the ADMS, which is are required to operate a grid increasingly reliant upon customer-sited resources.

The ADMS offers distribution system operators a new way of managing the grid. Change management and training will play a significant role in maximizing the use of these capabilities. Introducing more field devices over time will allow operators to become more familiar with ADMS capabilities before widespread deployment.

The Companies currently intend to file an application for the broad deployment of field devices in the second half of 2020. In the meantime, under current existing budgets, the Companies will continue to install these field devices when needed to fill operational needs or

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[25] See *Planning Hawai'i's Grid for Future Generations*, filed on March 1, 2018 in Docket No. 2017-0226, and Integrated Grid Planning Workplan, filed on December 14, 2018, in Docket No. 2018-0165 – available at http://www hawaiianelectric.com/igp.
[26] See Docket No. 2014-0183, Decision and Order No. 34696, issued on July 14, 2017.

address issues on the distribution system. These initial field device deployments will be both useful and will add additional value when interfaced with the ADMS.

In addition, as the FAN and number of field devices grows, upgrades to the Companies' network operations center ("NOC") may be needed to further monitor and administer the telecommunications system. the Companies' NOC was initiated in 2018, and provides real-time network and system monitoring to prevent, assess, and respond to anomalous activity, both malicious and operational. For Grid Modernization, as visibility and control start to extend to the grid edge, the Companies will be facing expanding potential threats of varying types. As the Grid Modernization deployments continue to evolve, the Companies will evaluate what additional investment for upgrades and capabilities will be required of the NOC to continue to extend its preventative controls for their networks and systems. Additionally, a distribution operations center ("DOC") may be needed for system operators to interface with the ADMS and manage the distribution system.

Both the MDMS and ADMS include analytics and reporting capabilities to provide insight for grid operation as well as distribution engineering and planning, including asset management systems with the capability of condition-based monitoring. Data can also be exported to analytics packages like the Synergi distribution planning tool, including Asset Management with the capability of condition-based monitoring, or the DEMS and MDMS for DR/DER Measurement & Verification ("M&V"). However, once the MDMS and the ADMS are operational, the Companies may identify gaps in analytics capabilities based on the insights needed for grid operations, engineering, and/or planning. It is possible that an additional analytics engine will be needed to provide that additional insight.

The GMS proposed investments through 2023; however, the Companies will need to continue to invest in and modernize the grid beyond Phase 2, which continues through 2024. Technology is evolving at a rapid pace, and the adoption of DER and renewable resources in pursuit of the RPS goals creates very dynamic conditions on an evolving distribution grid. As a result, the Companies will need to assess the needs of the customers and the grid in order to pair the appropriate technology that is available. The IGP process will identify any new projects and the priorities for future grid investment and modernization. Taking these into consideration, the Companies will need to evaluate whether the continued efforts can proceed under the Companies' normal budgeting processes or whether any additional Commission approvals will be required.

VIII. ADMS PROJECT

The Project focuses on deployment and integration of a commercially available ADMS software solution for all three operating Companies. The Project will implement an ADMS in the Companies' grid control rooms that will provide greater visibility, control, and optimization of the distribution system for more reliable operations of a two-way grid with increasing DER and interfacing microgrids.

Currently, the Companies are managing the bulk power system without visibility into or control over the vast majority of distribution resources or the operating state of the distribution network. Limited tools are available, and primarily manual processes are used to operate the distribution system, with its unprecedented levels of renewable penetration and widespread reverse power flows. These distributed resources have a substantial impact on both the distribution system and the bulk grid, and the lack of visibility and control over such a major component of the total grid energy is unsustainable. The ADMS will provide the grid operators

the visibility and control needed to operate a modern grid while maintaining or enhancing cyber security.

Additionally, the solution will improve resiliency following disruptions by enhancing situational awareness and assisting in restoration triage to recover from events faster. The existing outage management processes will also be modernized to leverage the ADMS Outage Management System ("OMS") reporting and automation features that improve customer communications, incident response, and operational efficiency.

A. PROJECT DESCRIPTION

Vendor-supplied ADMS solutions are typically comprised of four foundational features: (1) an OMS used to manage and track outages; (2) a Distribution Management System ("DMS") that monitors and controls switching at the distribution level, including distribution SCADA, in conjunction with Distribution Automation ("DA"); (3) "Advanced Applications" analytic functions for forecasting, simulating, studying, and optimizing the impacts of different network switching configurations and loading conditions; and (4) a Distributed Energy Resource Management System ("DERMS"). The Companies have already implemented the DERMS through the DRMS project and the resulting DEMS implementation. This Application addresses the need to implement the remaining three modules of an ADMS. Figure 2 illustrates these four ADMS components and their various functional modules.

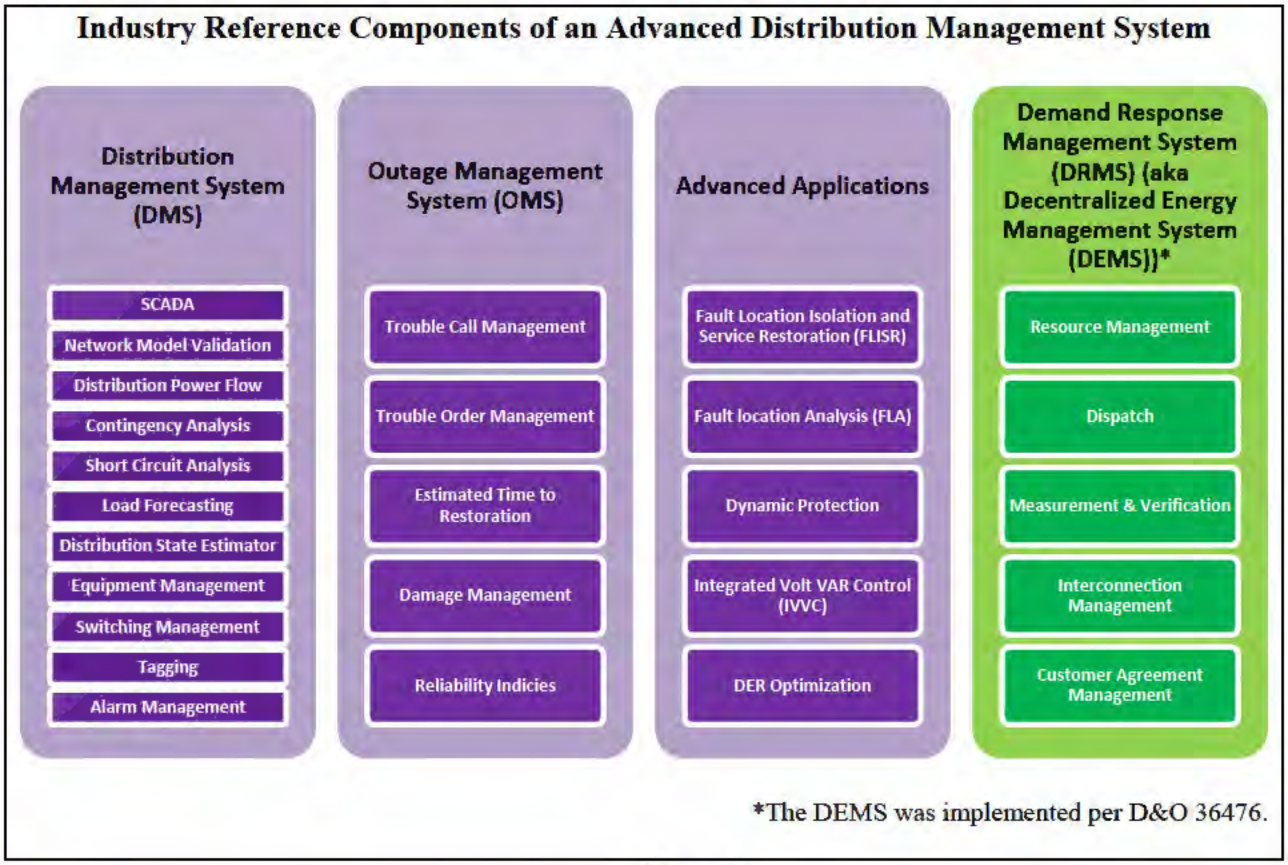

Figure 2

The ADMS will also interact with other operational and corporate systems to provide context to the stream of data. For example, the ADMS will integrate with the DEMS system and each Company's existing Energy Management System ("EMS") to coordinate DER commands and dispatch.

The Companies plan to deploy the ADMS over three Releases, summarized below and shown in Figure 3, with each Release layering additional capabilities and more sophisticated controls while maintaining cyber security. Exhibit B (*GMS Phase 2 ADMS Project Justification with Business Case Support*) and Exhibit F (*GMS System Architecture and Cyber Security*) provide more detailed information about the ADMS components and related integrations.

- **Release 1 – Deploy Basic ADMS Features to all Companies and system-level DER Functions**
    - Basic OMS features – Replacement of the Hawaiian Electric OMS and installation of OMS on Maui Electric and the Hawai‘i Electric Light , including outage tickets, outage call handling, training simulator, mobile client;
    - Basic Distribution Management (DMS) features[27] – Distribution SCADA for Hawaiian Electric, switch order handling for Hawaiian Electric, load forecasting, powerflow analytics, study mode;
    - Basic SCADA features via Inter-Control Center Protocol (ICCP) – telemetry only (no controls) via one-way integrations from existing EMS at each Company;
    - Basic demand response (DR) and distributed energy resource (DER) features – to dispatch demand-side flexibility programs via the existing DEMS; future microgrids and
    - Integration with other key enterprise applications – GIS, SAP, AMI/MDMS, DEMS, and Asset Management Systems.
- **Release 2 – Deploy Additional ADMS Features and localized DER Functions to all Companies**
    - Advanced features include distribution state estimation (DSE), fault location analysis (FLA), fault location isolation and service restoration (FLISR), and primary connected utility controlled DER;
    - Implementation of Distribution SCADA for telemetry and control of distribution field devices and DERs on the distribution primary-side;
    - Additional SCADA integrations with EMS to receive transmission state estimator values and pass controls to EMS managed devices and resources; and
    - Ability to monitor and adjust the real or reactive power injection of large DER; and
    - Integration with wind and solar forecasting services from UL/AWS and simulation software models such as Synergi.

[27] Hawai‘i Electric Light’s and Maui Electric’s EMS contain distribution SCADA information down to the distribution circuit breaker. This will remain in the EMS.

- ***Release 3 – Deploy Advanced DA and optimize DER Features for all Companies***
    - Advanced DA (distributed automation) integration includes volt-var optimization (VVO) and advanced protection equipment coordination schemes;
    - Advanced DER integration includes forward-looking contingency analysis, predictive DER scheduling, and load shedding algorithms;
    - Additional integrations to field volt-var control devices, protection, and switching equipment; and
    - Enhanced integration to DEMS to enable status, availability, and control of all customer-sited DERs, including active loads, DGPV, battery controllers, microgrids, and electric vehicle charging.

1. <u>System Integration</u>

The ADMS must be integrated to other enterprise systems to realize its full potential, as described in Exhibit B (*GMS Phase 2 ADMS Project Justification with Business Case Support*) and Exhibit F (*GMS System Architecture and Cyber Security*). It utilizes the geographic information system ("GIS"), grid connectivity model, and telemetered data from field devices to understand the current configuration of the grid as well as all other possible configurations of the distribution system. Integration with the advanced meters will enable their sensing capabilities to notify the Companies when customers are experiencing an outage or abnormal voltage conditions. Integration is required with the DEMS to dispatch demand-side DR/DER flexibility for local grid services like reserve capacity, power quality, and highly surgical ancillary services. Additional system integrations include interfaces with: (a) the existing EMS on each island for coordination with transmission operations; (b) the SAP customer information and customer care system used by the call center; (c) the Synergi grid planning software; and (d) third-party wind and solar forecasting vendors.

The Commission previously approved the implementation of a DRMS, which will evolve into a DERMS through the Companies' implementation of the DEMS.[28] The ADMS will interface with the DEMS in order to dispatch customer-owned DER resources that participate in customer energy options.[29] The DEMS will manage the customer- and aggregator-facing aspects of the available customer energy options, while the ADMS will manage the distribution system and dispatch DER as needed to meet grid needs. For example, as part of the IGP process, the Companies are conducting a "soft launch" of Non-Wired Alternatives ("NWA") to address capacity constraints in two areas: (1) Hoʻopili; and (2) East Kapolei.[30] Once implemented, the ADMS will monitor to determine when the dispatchable distributed resources (e.g., Demand Response and/or Energy Storage) in those two areas are needed to stay within the capacity rating of the infrastructure.

Capacity ratings specify the physical limitations on the amount of electricity that flows through a component of the power system. If those limits are exceeded for a sustained period of time, it could lead to safety issues, such as conductor or transformer failure. The ADMS will be used to send a dispatch request to the DEMS, which will, in turn, relay that command to the

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[28] See Docket No. 2015-0411, Decision and Order No. 34884, issued on October 18, 2017. The DEMS is the name of the product that was approved in the DRMS docket. As the Commission recognized with D&O 36476, the line between DR and DER is nuanced from a policy and program perspective. Similarly, the differentiation between the functions associated with the management software capabilities is nuanced. For the purposes of the Companies' selected architecture, we will be discussing things in terms of DEMS and ADMS. The industry terms of DRMS and DERMS do not comport neatly with the Companies' unique and industry-leading vision wherein customer-cited resources will be relied upon for routine grid operation.

[29] The term "customer energy options" as utilized in this Application is inclusive of existing and new tariffs and/or programs including Demand Response ("DR") Portfolios (including Time-of-Use ("TOU") and future dynamic pricing) and DER programs. All of these options would be inclusive of any customer-sited resources, including but not limited to photovoltaics ("PV"), distributed storage, and electric vehicles ("EVs").

[30] See https://www.hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning/stakeholder-engagement/working-groups/distribution-planning-and-grid-services-documents.

participating DER aggregator(s) and/or participating customers to adjust their output in a way that decreases the capacity rating exceedances. Subsequent to dispatch, the GMS Phase 1 advanced meters will provide interval data through the MDMS, which in turn will provide it to the DEMS to perform the Measurement and Verification ("M&V") performance evaluation of the customer-owned resources and the aggregated DR/DER resource(s).

2. <u>Cyber Security</u>

Existing SCADA-controlled devices on the electrical grid are typically located at transmission and distribution substations, which are physically secured with perimeter fences, locked gates, and in some cases, monitored by cameras to detect any intrusion or suspicious activity. Telecommunications to the SCADA-controlled devices occurs through the Wide Area Network ("WAN"), and the Energy Management System (EMS) manages these devices. The Companies' EMS systems are located in separate data centers from the corporate data center, ensuring an isolated and independent cyber security environment from the corporate IT systems. Similarly, the ADMS will be managed from distribution control centers and located in data centers separate from the corporate data centers.

The ADMS will utilize the FAN, as well as the WAN where possible, to communicate with field devices. Additionally, some SCADA assets may transition from EMS to ADMS control, depending on where the SCADA system is located on the transmission or distribution grid. As more distribution-level field devices and customer-owned devices are added to the ADMS for system visibility, cyber security measures will be required to ensure safe, secure, and reliable operation of the electrical grid.

The introduction of DER and distribution-level field devices exposes more points of access on the grid, and each point of access is a potential vulnerability to the distribution grid.

Integration between the ADMS in order to dispatch DR and DER through the DEMS may utilize non-utility owned communication paths from the DEMS to the DER aggregator and participating customer, including customer broadband or cellular connections. Therefore, systems such as the MDMS, DEMS, and ADMS must be implemented with comprehensive cyber security measures built into the overall architecture of the systems and integrated into operational processes and procedures. See Exhibit F (*GMS System Architecture and Cyber Security*) for additional discussion.

3. Training

The Companies have an established training system for system operators utilizing existing tools such as the EMS and the OMS on O‘ahu. Each position has minimum requirements of classroom time and on-the-job training before system operators are allowed to perform their functions independently. Each position requires a minimum training time of one to two years before a system operator is fully proficient. In addition, each of the island utility grids have operated as independent grid operators, each with their own set of processes, rules, and training systems.

The ADMS is one of the foundational tools for the distribution system operators, transitioning from operating system–level devices toward understanding more complex and more abundant paths of electricity flow at the distribution level. In the case of Hawaiian Electric, which has an existing OMS, the system operators will be required to learn additional features of the ADMS that come with DMS and the Advanced Applications of the ADMS. The Maui Electric and Hawai‘i Electric Light system operators will be required to learn OMS, DMS, and Advanced Applications of the ADMS. Investment into an ADMS requires training in order to ensure that the Companies realize the full value of the ADMS investment. The Companies’

desire is to approach the Project with a discipline of not only implementing an ADMS project but also gaining efficiencies by standardizing processes amongst the Companies and standardizing the look, feel, and operation of the ADMS for all three. As learned through the Hawaiian Electric OMS project, using a training simulator is one of the most effective ways to train system operators. This places the operator in an environment where the system is not affected by their actions, yet operators can visualize all of the inputs the ADMS will provide and understand how their decisions can be made based on the information they will be seeing when the ADMS goes live. This decreases the number of mistakes and shortens the learning curve for the system operators.

B. PROJECT BENEFITS

Managing the electrical grid of today and the future requires new systems in the control room to facilitate existing reliable and optimized integration of distributed, variable, and renewable resources. As stated earlier, the Companies are managing the bulk power system without visibility into or control over for the vast majority of distribution resources or the operating state of the distribution network. Current tools are limited, and manual processes are used to operate a distribution system that is experiencing pioneering levels of renewable penetration and widespread reverse power flows. These distributed resources have a substantial impact on both the distribution system and the bulk grid, and the lack of visibility and control over such a major component of the total grid energy is unsustainable. The ADMS will provide the grid operators this visibility and control to operate the grid, which will lead to additional benefits for managing the electrical grid. The benefits of an ADMS can be summarized in three broad categories:

1) **Enable customer energy options while advancing clean energy goals** – An ADMS is critical to continuing the growth of DER with variable and two-way flows while maintaining safety and acceptable system reliability. The ADMS will provide operational visibility, monitoring, and analytics that can facilitate safe, reliable operation of a large amount of energy sources on the distribution system. The ADMS will be the coordination hub of a distributed, layered architecture approach, as presented in Figure 5 from the GMS.[31] The ADMS is an integral part of the overall Grid Modernization Strategy: it is the central control system that provides grid edge visibility, control, and optimization to enable safe and reliable interconnection of DER and microgrids, and monitoring, command and control of field devices. Without the investment in an ADMS, the distribution grid capability to support customer energy options will be limited and the respective benefits of these options will not be fully realized.

2) **Improve system reliability and customer communications** – The primary purpose and benefit for implementing the OMS module of an ADMS is to reduce outage restoration time, as measured by the System Average Interruption Duration Index ("SAIDI") and Customer Average Interruption Duration Index ("CAIDI"). Improvements in SAIDI and CAIDI are achieved by improving the ability of the control room to identify the location and causes of faults, prioritizing outages based on customers affected, and optimizing the dispatch of field technicians. By

[31] GMS , at 20.

implementing an ADMS, the Companies can better meet customer, local media, and government expectations of increased communication and detailed operations information during both normal and emergency situations. Recent years have required frequent emergency incident response events due to tropical storm threats and volcanic eruption impacts, requiring the entire System Operations and Planning divisions to participate in coordinated emergency response and to develop communications plans for resilience and restoration. Having an ADMS that allows the Companies' system operators to better understand such situations will allow the Companies to better coordinate response and keep the community informed.

3) **Enhance operational resiliency and efficiency** – The ADMS will provide operators with improved visibility, control, and optimization of contingency situations and protection schemes. The ADMS Study and Powerflow functionality allows operators to analyze distribution grid-edge voltage support and to short-circuit current availability while supporting analysis of the impact of potential events. ADMS also provides a platform that can be used to integrate grid-tied storage batteries and local microgrids, which can then be incorporated into restoration and recovery plans. In general, the ADMS will support complex contingency, as well as state estimation analysis to include consideration of the distribution systems since smaller DER assets increasingly provide a majority of total grid energy. Additionally, the ADMS solution will improve resiliency and analysis following disruptions by enhancing situational awareness and assisting in restoration triage to recover from events faster.

These benefits are consistent with the guiding principles, regulatory goals, and priority outcomes defined by the Commission in the recently published Performance-Based Regulation ("PBR") framework.[32]

Please see Exhibit B (*GMS Phase 2 ADMS Project Justification with Business Case Support*) for a more detailed description of the benefits associated with this Project.

C. PROJECT COSTS

As detailed in Exhibits B (*GMS Phase 2 ADMS Project Justification with Business Case Support*) and H (*Bill Impact*), the Companies estimate the total Capital, Deferred, and O&M costs of the Project through implementation to be $45.8 million. These costs include [redacted] in implementation and support costs expected to be incurred following Commission approval (assumed in 2020) through the end of 2024 and [redacted] in pre-implementation O&M expenses. In addition to the $45.8 million in implementation costs, beginning in 2025 the Companies estimate that they will incur [redacted] in ongoing, incremental O&M expenses annually..

The Capital, Deferred, and O&M costs for the Project's implementation include costs for: (1) internal labor; (2) materials; (3) outside services; (4) other; (5) overheads; and (6) AFUDC, as described in Exhibit B (*GMS Phase 2 ADMS Project Justification with Business Case Support*). These include costs for products and services to be supplied by third-party vendors. As detailed in Exhibit E (*Request For Proposal*), the Companies obtained vendor responses through their formal RFP process.

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[32] See Docket No. 2018-0088, Decision and Order No. 36326, issued on May 23, 2019.

D. ANTICIPATED IMPLEMENTATION SCHEDULE

As noted above, the Companies plan to implement the ADMS over three Releases, each adding additional capabilities and sophistication. The entire ADMS deployment spans three Releases (described above) and will last approximately four years, as depicted in Figure 33.

Scope	**Current Year**	**Year 1**	**Year 2**	**Year 3**	**Year 4**
Job Analysis Pre-Implementation Work					
Release 1 - Deploy basic ADMS features to all Companies and enable system-level DER functions					
Hawaiian Electric					
Maui Electric					
Hawai'i Electric Light					
Release 2 - Deploy additional ADMS features and localized DER functions to all Companies					
Hawaiian Electric					
Maui Electric					
Hawai'i Electric Light					
Release 3- Deploy advanced DA and optimize DER features to all Companies					
Hawaiian Electric					
Maui Electric					
Hawai'i Electric Light					

Figure 3 ADMS Implementation Schedule

IX. ACCOUNTING AND RATEMAKING TREATMENT

The Companies are requesting approval to recover the Capital, Deferred, and O&M costs of the Project implementation (totaling [redacted]), [redacted] of pre-implementation O&M expense, and [redacted] of annual, incremental post-implementation O&M expenses. The accounting and ratemaking treatment proposed to be applied to the Project is detailed in Exhibit C (*Accounting and Ratemaking Treatment*) and in Exhibit D (*Interim Recovery*).

A. ACCOUNTING TREATMENT

The proposed accounting for the Project generally follows the accounting for capital expenditure and software projects approved by the Commission in the past. In general, the cost of equipment and hardware will be capitalized and depreciated based on depreciation rates in place at the time of this filing, while software and related development costs will be deferred and amortized over a 12-year period. Such treatment is in accordance with Generally Accepted Accounting Principles ("GAAP") and consistent with the Companies' current accounting for such costs. Costs related to software development for the ADMS and system integration work will follow the Companies' existing accounting policy, which is consistent with the Financial Accounting Standards Board's ("FASB") Accounting Standards Codification ("ASC") 350-40, "Internal-Use Software."[33] The Companies will incur incremental Expense Costs for training, as well as on-going post-implementation costs to operate and maintain the ADMS. To the extent that these costs are not recovered in current rates, the Companies plan to seek recovery of these costs through the MPIR adjustment mechanism, or if the Commission is not inclined to allow MPIR recovery, through future rate cases.

Additionally, the Companies are seeking to defer O&M costs incurred prior to Commission approval for training and change management pre-implementation costs that are necessary for a successful implementation. To the extent that these costs are not recovered in current rates, the Companies plan to seek recovery of these costs through the MPIR adjustment

[33] Formally known as Statement of Position 98-1, "Accounting for the Costs of Computer Software Developed or Obtained for Internal Use," issued in March 1998.

mechanism, or if the Commission is not inclined to allow MPIR recovery, through future rate cases.

The proposed accounting for each of the components of the Project is described in Exhibit C (*Accounting and Ratemaking Treatment*).

B. <u>INTERIM RECOVERY</u>

As requested above, the Companies are seeking recovery of the Capital Costs, Deferred Costs, and Expense Costs of the Project through the MPIR adjustment mechanism until base rates that reflect the revenue requirements associated with those costs take effect in a future rate case for each respective company.

The purpose of the MPIR is to provide a mechanism for recovery of revenues for net costs of approved "Eligible Projects" placed in service between general rate cases that are not provided for by other effective tariffs.[34] As noted in Exhibit D (*Interim Recovery*), attached hereto, the Companies maintain that the Project qualifies as an eligible project under Sections III.B.1(b) (projects that make it possible to accept more renewable energy); III.B.1(c) (projects that encourage clean energy choices and/or customer control to shift or conserve their energy use); III.B.1(d) (approved or accepted plans, initiatives, and programs); and III.B.1(f) (grid modernization projects) of the MPIR Guidelines. In addition, as further discussed in Exhibit D (*Interim Recovery*), the instant Project application, including the attached business case,[35] satisfies the criteria set forth in the MPIR Guidelines. A detailed illustrative MPIR calculation

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[34] MPIR Guidelines, Section II.A at 2.
[35] <u>See</u> Exhibit B (*GMS Phase 1 Project Justification and Business Case Support*), Docket 2018-0141.

for the Project is provided in Exhibit I (*Hawaiian Electric Companies' Decoupling Calculation Workbook*).

In the alternative, as discussed in Exhibit D (*Interim Recovery*), if the Commission is not inclined to allow the Companies to recover the Capital Costs, Deferred Costs, and Expense Costs of the Project through the MPIR adjustment mechanism, then the Companies request approval to recover the these costs through a future rate case for each respective company, with amortization of the Deferred Costs commencing when base rates that reflect the Deferred Costs take effect in those respective proceedings.

C. BILL IMPACT

As shown in Exhibit H (*Bill Impact*), the Companies estimate that the average monthly bill impact of the Project for a typical residential customer would be:

- $0.24 at Hawaiian Electric for a customer using 500 kWh, ranging from $0.02 to $0.35;
- $0.76 at Maui Electric for a customer using 400 kWh, ranging from $.02 to $1.12; and
- $0.72 at Hawai‘i Electric Light for a customer using 500 kWh, ranging from $0.02 to $1.07.

X. CONCLUSION

Wherefore, the Hawaiian Electric Companies respectfully request a decision and order approving:

(1) Implementation of the proposed Project;

(2) A commitment of funds in excess of $2.5 million for the Capital Costs of the Project pursuant to G.O. 7 Paragraph 2.3(g)(2);

(3) The proposed accounting and ratemaking treatment for the Project, including:

(a) Deferral of the Deferred Costs of the Project pursuant to the Companies' Software Accounting Policy and D&O 18365;

(b) Accrual of AFUDC , as appropriate, while the software is under development for the Project, with a carrying cost equivalent to the AFUDC rate applied to the deferred costs after the software is in use until the deferred costs are included in rate base in determining rates;

(c) Recovery of the Capital Costs and Deferred Costs through the MPIR adjustment mechanism established in Order 34514, until base rates that reflect the revenue requirements associated with the Capital Costs and Deferred Costs of the Project take effect in a future rate case for each respective Company, provided however that if the Commission is not inclined to allow the Companies to recover the Deferred Costs through the MPIR adjustment mechanism, then in the alternative, the Companies request approval to recover the Deferred Costs, with a carrying cost equivalent to the AFUDC rate applied, through a future rate case for each respective Company, with these deferred costs being amortized over 12

years, beginning when such amortization is included in rates, and the unamortized deferred costs are included in rate base; and

(4) Recovery of O&M costs, including:

(a) Deferral of the O&M Costs incurred during the Project implementation; and

(b) Deferral of the annual, incremental post-implementation O&M Costs with recovery through the MPIR adjustment mechanism, until base rates that reflect the O&M Costs of the Project take effect in a future rate case for each respective Company, provided however that if the Commission is not inclined to allow the Companies to recover the O&M Costs through the MPIR adjustment mechanism, then in the alternative, the Companies request approval to defer and recover the O&M Costs, with a carrying cost equivalent to the AFUDC rate applied, through a future rate case for each respective company, with the Deferred costs being amortized over 12 years, beginning when such amortization is included in rates, and the unamortized deferred costs are included in rate base;

(5) Deferral treatment of pre-implementation O&M costs incurred prior to Commission approval; including recovery of the deferred O&M Costs through the MPIR adjustment mechanism, until base rates that reflect the O&M Costs of the Project take effect in a future rate case for each respective Company, provided however that if the Commission is not inclined to allow the Companies to recover the O&M Costs through the MPIR adjustment mechanism, then in the alternative, the Companies request approval to recover the deferred O&M Costs, with a

carrying cost equivalent to the AFUDC rate applied, through a future rate case for each respective company, with the Deferred costs being amortized over 12 years, beginning when such amortization is included in rates, and the unamortized deferred costs are included in rate base; and

(6) Such other and further relief as may be just and equitable in the premises.

DATED: Honolulu, Hawai'i, September 30, 2019.

HAWAIIAN ELECTRIC COMPANY, INC.
HAWAI'I ELECTRIC LIGHT COMPANY, INC.
MAUI ELECTRIC COMPANY, LIMITED

By ______________________

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

Vice President
Hawai'i Electric Light Company, Inc.
Maui Electric Company, Limited

VERIFICATION

STATE OF HAWAIʻI)
) ss.
CITY AND COUNTY OF HONOLULU)

JOSEPH P. VIOLA, being first duly sworn, deposes and says: That he is Vice President of Hawaiian Electric Company, Inc., Hawaiʻi Electric Light Company, Inc., and Maui Electric Company, Limited, Applicants in the above proceeding; that he makes this verification for and on behalf of said Applicants, 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.

Joseph P. Viola

Subscribed and sworn to before
me this 30th day of September, 2019.

LISA ANN S. YAMADA

Notary Public, First Circuit,
State of Hawaiʻi

My Commission expires 10-10-2019

LISA ANN S. YAMADA NOTARY PUBLIC No. 99-488 STATE OF HAWAII

STATE OF HAWAIʻI NOTARY CERTIFICATION

Doc. Date: 9/30/19 # of pages 193

Notary Name: LISA ANN S. YAMADA First Circuit

Doc. Description: Verification

Notary Signature Date 9/30/19

LISA ANN S. YAMADA NOTARY PUBLIC No. 99-488 STATE OF HAWAII

Exhibit A

GMS Phase 2 ADMS Application

Grid Modernization Strategy Working Plan

GRID MODERNIZATION STRATEGY WORKING PLAN

On August 29, 2017, the Hawaiian Electric Companies[1] filed their final Grid Modernization Strategy ("GMS")[2] with the Hawai'i Public Utilities Commission ("Commission") following several months of stakeholder engagement and a public comment period. The GMS provides near- and long-term plans for the Companies' proposed design to deploy advanced technologies and back office systems that will integrate new technologies and processes with the existing infrastructure to update the electric grid, which will pave the way for the Companies to achieve Hawai'i's 100% RPS goal by 2045.[3] Following Commission approval of the GMS,[4] the Companies have moved forward to implement the Strategy, starting with the approved GMS Phase 1 ("Phase 1")[5] and the Integrated Grid Planning ("IGP") activities.[6] In adherence with D&O 35268, this 10-page GMS Working Plan offers further context on how the Companies intend to implement the GMS, the expected outcomes of each application, the interdependencies between each application, and the expected time frame for when the Companies intend to submit each subsequent application to the Commission for approval.

As has been previously articulated, the Companies have divided the implementation of the GMS into multiple phases. Each phase will build and expand the existing electric grid into a modernized one using a logical progression of features and functionality. The maturity of the different components of grid modernization,[7] as well as the prioritized need for the functionality and capabilities of each component, drive the ordering and sequencing for each phase of the implementation. The Application ("Application") for the Advanced Distribution Management System ("ADMS") component, herein referred to as the Project ("Project"), of GMS Phase 2 ("Phase 2") builds upon the Phase 1 efforts as well as the Companies' Demand Response initiatives.[8] Subsequent GMS applications and phases will layer additional technologies to further evolve the grid, adding advanced operational capabilities at a pace that will meet customer needs and create customer value while remaining flexible to adopting emerging technologies.

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

[2] See Docket No. 2017-0226, *Modernizing Hawai'i's Grid For Our Customers*, filed August 29, 2017.

[3] See Hawai'i State Energy Office, Grid Modernization, Renewable Portfolio Standard ("RPS") targets, available at http://energy.hawaii.gov/renewable-energy/grid-modernization.

[4] See Docket No. 2017-0226, Decision and Order No. 35268, issued on February 7, 2018 ("D&O 35268").

[5] See Docket No. 2018-0141, Decision and Order No. 36230, issued on March 25, 2019.

[6] See Docket No. 2018-0165, Decision and Order No. 36218 and *Integrated Grid Planning Report* and *Integrated Grid Planning Workplan*, issued on December 14, 2018.

[7] See the U.S. Department of Energy's Next Generation Distribution System Platform ("DSPx"), Volume II, *Advanced Technology Maturity Assessment*, available at http://doe-dspx.org/sample-page/dspx-volumes/.

[8] See Docket 2015-0412, Decision and Order No. 35238, issued on January 25, 2018; Docket No. 2015-0411, Decision and Order No. 34884, issued on October 18, 2017.

I. GMS IMPLEMENTATION SCHEDULE

The Companies' implementation plan has remained relatively stable since the approval of the GMS. The multiple phases for their GMS implementation, which were depicted in the Phase 1 Application, is updated below. This Project will empower grid operators with the requisite software to effectively manage a grid reliant upon renewable and distributed energy resources. The planned ADMS release schedule will effectively build capabilities over time to enable the distribution system monitoring and control and automation functionality required to safely and reliably support a distributed and renewable resource future.

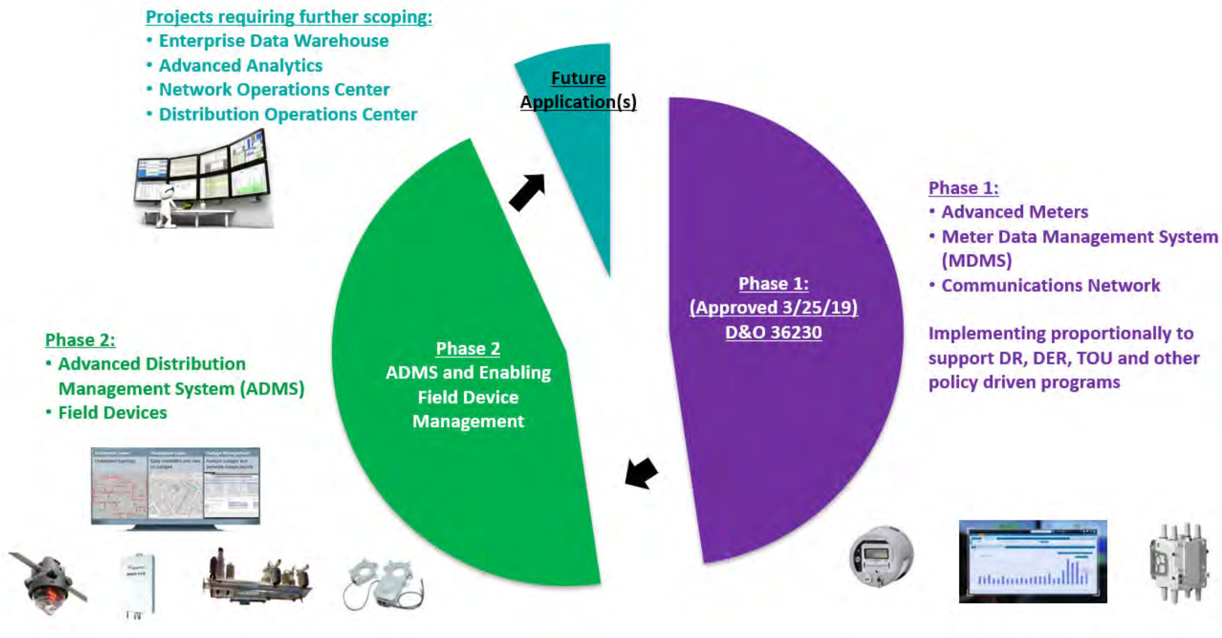

Figure 1

The Companies' Strategy continues to align with the walk-jog-run analogy of the GMS to build capabilities over time in a coordinated, conscientious, and prudent manner. Therefore, the work plan has been updated with stakeholder and Commission input and will continue to adapt to system needs relative to vendor maturity. For example, the field devices (such as line sensors, secondary var controllers, remote intelligent switches, and fault current indicators) that were initially identified as a part of Phase 2 are now being considered for a subsequent application in lieu of being included with the instant ADMS Application. While the Companies are ready to proceed with the ADMS, the details of which are detailed in this Application, the Companies are continuing to refine their deployment plan for the field devices in order to maximize customer value. The timing for the deployment of these devices is being planned to coincide with the enabling capabilities provided in the sequence of ADMS releases. Additionally, the Wi-SUN standard for the FAN telecommunications that is being deployed as part of Phase 1 will provide the telecommunications platform necessary for advanced meters and future field devices to utilize the same FAN network with multi-vendor interoperability. However, Wi-SUN completed their testing and certification criteria in October 2018 and the Companies' field device manufacturers are investigating Wi-SUN certified telecommunications for their network

interface cards.[9] Finally, the IGP working group activities may provide additional insight into the distribution planning criteria for field device deployment.

The scope for future phases of the GMS implementation will be informed by an assessment of required supporting capabilities, including expanded data management, a field network operations center ("NOC"), and enhanced operational human-machine interfaces for distribution operators. Analytics needs beyond what is provided by the MDMS and the ADMS may lead to additional capabilities being requested for subsequent GMS implementation phases in the future. Additionally, the Phase 1 enablement of an online customer energy portal providing customers with energy usage data may expand in the future to include additional information such as billing data and estimated bill calculations. However, this additional investment should be driven by customer feedback as more customers receive advanced meters and gain access to the energy portal.[10] The Companies anticipate that any applications associated with future projects beyond this GMS Phase 2 ADMS Application will be submitted based on the scope and timing for investments in these grid modernization components and in coordination with broader enterprise systems planning processes that the Companies may undertake in the future.

II. <u>PHASE 2 GRID MODERNIZATION</u>

The Companies have been working to develop detailed grid architecture as well as functional requirements through use-cases to identify and document system requirements while also identifying associated Companies-specific business process changes that utilize the new systems and capabilities. This technique is a classic "people, process, and technology" impact analysis employed to successfully manage technology projects. The Companies applied lessons learned from both the Smart Grid Foundation Project ("SGFP") and the Phase 1 RFPs to issue the ADMS RFP. Evaluation of the ADMS RFP is discussed in Exhibit E (*Request for Proposal*) of this Application. Performing the planning, preparation, and due diligence up front reduces the risks associated with procurements and helps to ensure vendor and solution selections that are aligned with the GMS.

The goal of Phase 2 of the Companies' GMS implementation is to enable advanced distribution monitoring, control, and automation capabilities. To achieve this functionality, the Application includes an ADMS, which serves as a back office system that can efficiently monitor, visualize, and control distribution grid conditions and systems integration to connect the ADMS with existing Energy Management Systems, the recently approved Decentralized Energy Management System ("DEMS")[11], the Companies' current and future Geographic Information

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[9] <u>See</u> Wi-SUN Alliance, https://www.wi-sun.org/news/wi-sun-launches-fan-certification-program/.

[10] It would not be prudent to spend too much time, money, and effort on fully integrating the customer energy portal with the billing system while a broader customer facing solution is being contemplated and the number of customers with advanced meters is initially a small but expanding subset of customers.

[11] See Docket Nos. 2015-0411 and 2015-0412. The DEMS is the name of the product that was approved in the DRMS docket. As the Commission recognized with D&O 36476, the line between DR and DER is nuanced from a policy and program perspective. Similarly, the differentiation between the functions associated with the management software capabilities is nuanced. For the purposes of the Companies' selected architecture, we will be discussing things in terms of DEMS and ADMS. The industry terms of DRMS and DERMS do not comport

System ("GIS"), which tracks the geographic location of components of the distribution grid, and the Phase 1 components.

The ADMS builds upon the Phase 1 components, particularly maximizing the capabilities of the advanced meters and the FAN. The advanced meters perform three primary functions: (1) to serve as a grid sensor for operational awareness of the distribution system, (2) to educate distribution system planning activities to more confidently incorporate distributed energy resources, and (3) to efficiently enable measurement and verification as well as billing for complex rates and tariffs. The ADMS is the operational software system that enables the first function identified above by using a combination of data from advanced meters, field devices and existing Supervisory Control and Data Acquisition ("SCADA") systems. The ADMS relies upon the FAN as well as the Wide Area Network ("WAN") to provide the required telecommunication paths for grid sensing and control. These telecommunications components provide the ADMS with sensor data about the current state of the distribution grid in a timely manner so that the ADMS can provide distribution operators with situational awareness, actionable information, and controls for a safe and reliable distribution system with increasing amounts of renewable and distributed resources. This data can then be analyzed to better inform distribution planning models (the second function listed above).

A. ADVANCED DISTRIBUTION MANAGEMENT SYSTEM

An ADMS is a distribution management system with additional modules or functionality enabled, including an Outage Management System ("OMS") and fault location isolation and service restoration ("FLISR") functionality. Once operational, the ADMS becomes the platform for monitoring and controlling the distribution system. As the field devices, including advanced meters, report back data regarding distribution system conditions, the ADMS processes that data to assist grid operators via distribution state estimation, alerts to abnormal conditions, contingency analysis, and recommended switching schemes for load balancing or outage impact minimization. The systems integration of the meter data with the ADMS will enable the sensing capabilities of the advanced meters to notify the Companies when customers are experiencing an outage or abnormal voltage conditions. Integrating these systems will result in faster outage identification and restoration of customer service and improved power quality.

Of the Companies' three operating companies, Hawaiian Electric is the only one with an OMS today. The OMS module of the ADMS will therefore provide a significant improvement in outage management capability for both Maui Electric and Hawaiʻi Electric Light and an incremental improvement for Hawaiian Electric. The OMS will replace what is now a manual process to coordinate outage response at Maui Electric and Hawaiʻi Electric Light utilizing paper maps of the islands. Additionally, all three operating companies rely on customer phone calls to customer service representatives ("CSRs") to identify outages and estimate the extent of an outage. The OMS will automate certain aspects of that process, including utilization of outage alerts from advanced meters to identify the affected customers and integration with the SAP

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neatly with the Companies' unique and industry-leading vision wherein customer-cited resources will be relied upon for routine grid operation.

work management system to provide instructions to restoration field crews. Additionally, the ADMS advanced application FLISR module will further improve the Companies' outage response by identifying the potential root cause(s) of the outage, which can include identification of both the outage location and potentially the infrastructure components causing the outage, and recommending switching configurations to minimize the number of customers impacted by the outage.

A Distribution Management System ("DMS") is a collection of applications designed to monitor and control the entire distribution network efficiently and reliably. It acts as a decision support system to assist the control room and field operating personnel with the monitoring and control of the electric distribution system. The Companies today have an Energy Management Systems ("EMS"). An EMS is a system of computer-aided tools used by operators of electric utility grids to monitor, control, and optimize the performance of the generation or transmission system. Hawaiian Electric utilizes the Siemens Power TG EMS, and Maui Electric and Hawai'i Electric Light utilize the Alstom e-terra platform.[12] The Companies have complete SCADA systems at their higher voltage transmission substations. Over time, use of SCADA has progressively extended downward to the distribution systems. Hawaiian Electric utilizes its EMS to add distribution points of control and create a display for those distribution points. The Oahu EMS was not designed to be a DMS, thus this is a stopgap measure. The ADMS will provide DMS functionality, including distribution network model validation, distribution power flow, and switching management, which will provide a more sustainable way of monitoring and controlling the electric distribution system compared to adding it as points of control on the EMS. The Alstom e-terra platform on Maui and Hawai'i Electric Light contain modules, which enable a sustainable way to monitor and control down to the distribution breaker. Thus, Maui and Hawai'i Electric Light will continue to utilize their EMS to operate up until the distribution breaker. The DMS capability will be needed as the Companies begin adding devices on the distribution circuit and down to the customer level, and Maui and Hawai'i Electric Light can also take advantage of DMS features mentioned previously, such as distribution power flow and switching management.

The third and final grouping of ADMS capabilities is the Advanced Applications of an ADMS, which include Fault Location Analysis ("FLA"), FLISR, advanced protection schemes and device coordination, Integrated Volt-Var Control and DER Optimization. These advanced features build upon adding sensors in the field and performing analytics on the information feeding into the ADMS to further optimize the distribution grid.

If a favorable decision is made on the Project Application, the Companies plan to deploy an ADMS in three different releases. The first release will contain the OMS and system-level DER visibility and control and be operational within 24 months of the Commission's approval Releases 2 and 3 are expected to take about a year to deploy and will be implemented sequentially after Release 1 is complete. However, this estimate will be adjusted or validated once a statement of work is finalized with the selected ADMS vendor.

[12] In November 2015, General Electric (GE) completed the acquisition of Alstom Power and Grid businesses: https://www.genewsroom.com/press-releases/ge-completes-acquisition-alstom-power-and-grid-businesses.

1. <u>Systems Integration</u>

Grid modernization requires integrated systems that exchange information to manage the grid. The described ADMS functionality is enabled through a combination of data collection from deployed assets and data exchange with other systems. These systems and data integrations will be performed using a combination of internal and external labor. Capabilities will increase over time, with integration between the ADMS, the DEMS, and the MDMS to utilize increasing numbers of field devices and advanced meters that provide operational data for distribution management, outage management, volt-var optimization, and system data analytics. Figure 2 presents a high-level architectural view of the anticipated systems integration platforms that will be necessary as part of the GMS implementations as they progress, inclusive of their interrelationship with existing systems, such as the Energy Management System ("EMS"), and systems newly established, such as the DEMS. This architectural depiction also identifies the Commission docket associated with each component but does not speak directly to the functions of each system or the complexity associated with integrating and coordinating each actor. Additional information on the Companies' grid modernization architecture is included within Exhibit F of this Application (*GMS System Architecture and Cyber Security*).

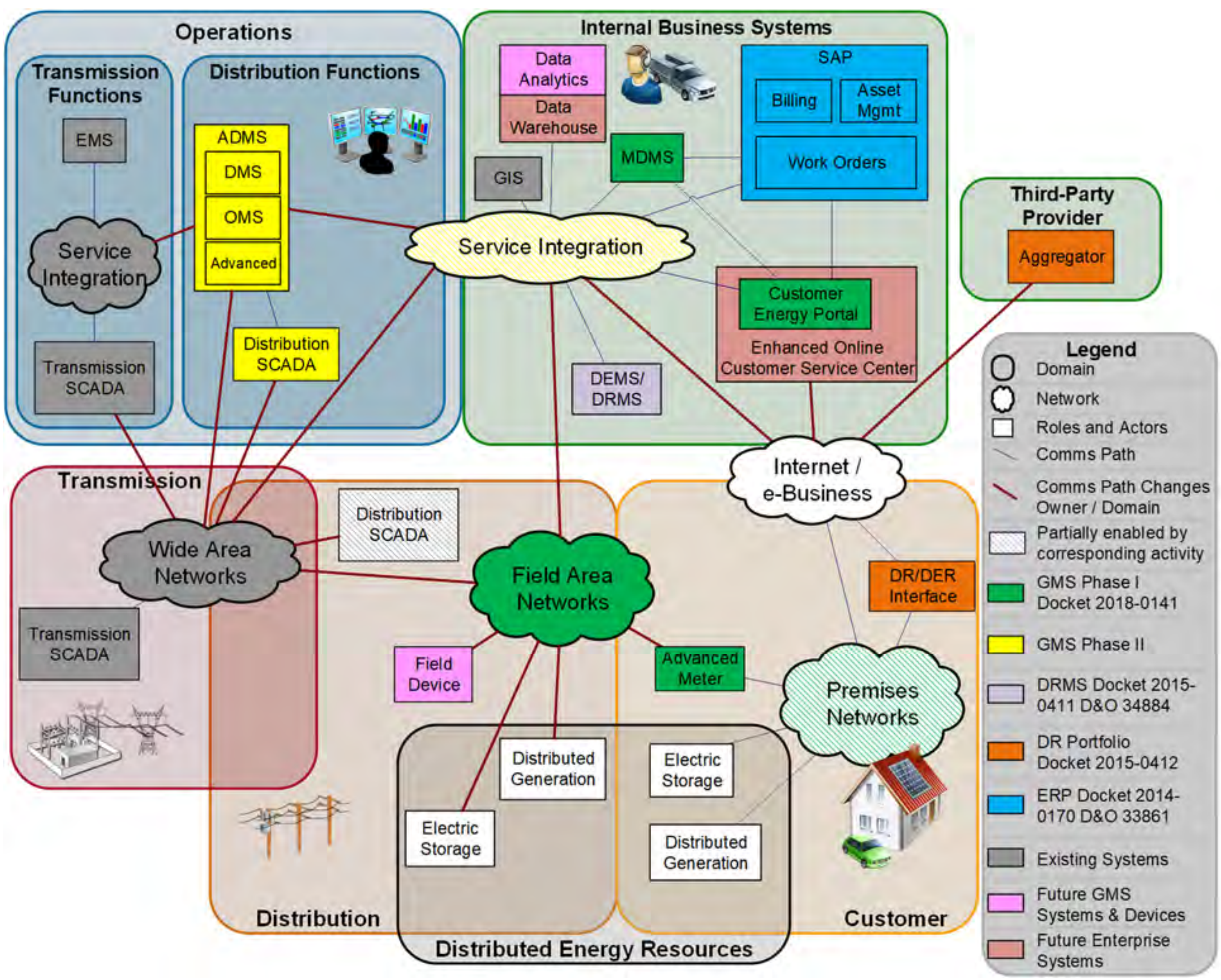

Figure 2

The success of achieving the grid modernization vision hinges on the Companies' ability to effectively implement, coordinate, and integrate each system and modernize the business processes to achieve the desired functionality.

B. FIELD DEVICES

Although the full implementation of field devices for the grid modernization effort will follow the approval of the forthcoming (future) application anticipated in the second half of 2020, the Companies are already deploying limited amounts of field devices through both field pilots under current budgeting processes to begin to address current needs for grid sensing and voltage control. However, the larger scale deployment associated with the field device component of Phase 2 GMS will not begin until Commission approval of the respective application. To maximize customer value, the Companies will further refine the forecasted number of devices through additional system evaluation prior to submitting the field device application.

For now, the Companies anticipate the need for the following field devices as part of an Application for Field Device funding. A summary of the envisioned field devices was described within the GMS, with each field device being enabled with two-way communication capability and integrated within the Companies' operational systems and educating planning activities.

- Remote Intelligent Switches – Sectionalizing and tie switches that enable shifting portions of one circuit to another for maintenance and outage restoration.

- Fault Current Indicators – Field devices that sense fault current to help determine the location of a fault.

- Line Sensors – Power quality monitoring devices that provide granular power characteristic measurements at targeted, high-priority areas.

- Secondary var controllers – Power electronics–based, fast-acting, decentralized shunt-var technology for voltage regulation. Other types of SVCs both absorb or inject vars at the circuit level and can also provide system monitoring capability if a telecommunication path is available.

The timing for the deployment of these devices is being planned to coincide with the enabling capabilities provided in the sequenced releases of the ADMS, which are described in Exhibit B (*GMS Phase 2 ADMS Project Justification with Business Case Support*). The field device application will also be closely coordinated with ongoing Integrated Grid Planning activities and the Companies' Rule 14H requirements for voltage regulation that maximizes smart inverter capabilities.

III. FUTURE PHASES FOR GMS IMPLEMENTATION

Some GMS components require further evaluation to determine the necessary scope to fulfill customer needs as well as the expectations of all stakeholders. One component being explored includes operational analytics tools to assist in examining the increasing volume of data that will be collected through the deployment of field devices and advanced metering. Analytics

capabilities, which both assist in more efficient grid operations and provide insight for future planning and forecasting, are continuing to evolve. The MDMS and ADMS solutions inherently provide some analytics capabilities; however, there may be gaps between the Companies' analytics needs and the capabilities provided by these products. Therefore, after the MDMS and ADMS are functioning, a gap analysis will be performed to determine what, if any, additional analytics capabilities are required to progress forward with future phases of the GMS.

Additionally, the Companies will need to explore the capabilities of the existing and planned infrastructure needed for a NOC to support network monitoring of the telecommunications solution as it expands over time. Similarly, a distribution operations center ("DOC") for the ADMS may be needed to allow system operators to manage the distribution system; although for now it is assumed that the requirements of the DOC will be incorporated into the existing operations dispatch center. However, additional infrastructure requirements will need to be further vetted during and following the implementation of GMS Phase 2.

Exhibit B

GMS Phase 2 ADMS Application

GMS Phase 2 ADMS Project Justification with Business Case Support

PROJECT JUSTIFICATION WITH BUSINESS CASE SUPPORT

I. INTRODUCTION

This project will implement a new Advanced Distribution Management System ("ADMS") in the Hawaiian Electric Companies' grid control rooms.[1] This solution will provide greater visibility, control, and optimization of the distribution system for more reliable operations of the two-way flow of electricity as the number and amount of distributed energy resources ("DER") continues to rise. Additionally, the solution will improve resilience by allowing operators to quickly adapt to changing grid conditions and rapidly recover following power outages and disruptions by enhancing situational awareness and assisting in restoration triage. The existing outage management processes will also be modernized to leverage ADMS reporting and automation features that improve customer communications, incident response, and operational efficiency.

II. BUSINESS CONTEXT

A. POWER SUPPLY IMPROVEMENT PLAN

The Hawaiian Electric Companies' December 2016 Power Supply Improvement Plan ("PSIP") update outlined the specific actions necessary to accelerate the achievement of Hawai‘i's 100% Renewable Portfolio Standard ("RPS") by 2045:

- Exceed Hawai‘i's 2020 RPS and achieve a consolidated RPS of 52% by 2021;
- Maximize DER – compensated;
- Make high use of demand response ("DR") programs;
- Aggressively seek grid-scale renewable resources, leveraging federal tax credits;
- Pursue grid modernization to enable continued integration of renewable energy;
- Preserve long-term flexibility to use emerging technologies and accommodate changing circumstances; and
- Reduce operations that use fossil fuels and contribute to reduce greenhouse gas emissions.

The prescribed actions take advantage of available resources, respond to customer preferences, and reduce dependence on oil and its price uncertainty as quickly as possible while

[1] The "Hawaiian Electric Companies" or the "Companies" are Hawaiian Electric Company, Inc. ("Hawaiian Electric"), Maui Electric Company, Limited ("Maui Electric") and Hawaii Electric Light Company, Inc. ("Hawai‘i Electric Light").

preserving flexibility over the longer term to address changing circumstances to take advantage of new opportunities that may arise and to explore emerging technologies.

B. GRID MODERNIZATION STRATEGY

Grid modernization is a foundational activity, required to realize Hawai‘i’s clean energy objectives while operating a safe and reliable electric grid. Integrating an increasing amount of customer-supplied renewable energy creates a critical need for modernizing the distribution grid and control room technology to support two-way power flows without sacrificing reliability or safety. This is necessary in order to accommodate expected growth of distributed generation photovoltaics (“DG” and “PV”, respectively) on O‘ahu, Maui, Moloka‘i, Lana‘i and Hawai‘i islands, respectively.

A modernized grid empowers customer choice and demand-side flexibility, where DER – including solar PV, battery energy storage systems (“BESS”), electric vehicles (“EV”), and DR resources – can be operated at every home. It supports the Electrification of Transportation (“EoT”) by enhancing the ability for the distribution grid to manage the variable demand of EVs, charging stations, roaming vehicle fleets, and mass transit systems. A modernized grid also supports smart cities and microgrids with improved ability to manage intermittent electrical islanding of distribution grid subnetworks.

The Companies’ Grid Modernization Strategy[2] provides near- and long-term plans for the Companies to deploy advanced technologies and back office systems to update the electric distribution grid. Phase 1 of the GMS consisted of advanced meters, a Meter Data Management System (“MDMS”), and Field Area Network (“FAN”) telecommunications. The Companies are now beginning to implement Phase 2 of the Strategy, which includes the implementation of an ADMS, which is critical to the continued addition of DERs, reduces outage restoration time, improves outage communication to the customer, improves visibility and control of DERs, and allows for optimization of all resources during normal operating conditions and in contingency situations. See Section IV for a more detailed benefits discussion.

C. ADVANCED DISTRIBUTION MANAGEMENT SYSTEMS

1. ADMS Components

Vendor-supplied ADMS solutions are typically comprised of four foundational features: (1) an Outage Management System (“OMS”) used to manage and track outages; (2) a Distribution Management System (“DMS”) that monitors and controls switching at the distribution level, including distribution SCADA, in conjunction with Distribution Automation (“DA”); (3) “Advanced Applications” — analytic functions for forecasting, simulating, studying,

[2] See “Modernizing Hawaii’s Grid For Our Customers,” filed in Docket No. 2017-0226 on August 29,2017 (“GMS,” “Grid Modernization Strategy,” or “Strategy”).

and optimizing the impacts of different network switching configurations and loading conditions; and (4) a Distributed Energy Management System ("DERMS"). The Companies have already implemented the DERMS through the Demand Response Management System ("DRMS") project and Decentralized Energy Management System ("DEMS") implementation.[3]

The goal of this Application is to enable the implementation of the remaining three ADMS modules. Representative components of these three ADMS modules include:

Components	**Description**
OMS Components	**Outage Management System Modules/Functionality**
Trouble Call Management	A module for accepting and recording trouble calls from customers. This includes outage and other trouble conditions.
Trouble Order Management	An outage management function that performs automatic grouping of trouble calls into trouble orders that represent the calls that are likely due to a common cause. Trouble orders can be sorted by multiple factors for restoration prioritization. Trouble Order Management includes a geographical map display for the System Operator. The OMS then coordinates associated trouble orders through SAP Work Orders to provide specific instruction and coordination to restoration field crews.
Estimated Time to Restoration	An estimate of the time until an outage is restored based upon known conditions, including time of day, number of crews on duty, outage prioritization rules, and size of outages. ERTs are calculated by an ADMS and are provided as a customer service. Outage management functions of an ADMS help maintain individual and global estimates of restoration times. Also sometimes called Estimated Restoration Time (ERT).
Damage Management	A module that assists field personnel who collect information on the location and types of damage observed in the field. The collected information is used in the ADMS to assist in making better assignments of crews, determining the equipment that is required for repair and also make

[3] See Docket Nos. 2015-0411 and 2015-0412. The DEMS is the name of the product that was approved in the DRMS docket. As the Commission recognized with D&O 36476, the line between DR and DER is nuanced from a policy and program perspective. Similarly, the differentiation between the functions associated with the management software capabilities is nuanced. For the purposes of the Companies' selected architecture, we will be discussing things in terms of DEMS and ADMS. The industry terms of DRMS and DERMS do not comport neatly with the Companies' unique and industry-leading vision wherein customer-cited resources will be relied upon for routine grid operation.

	better estimates of restoration times. Sometimes also called Damage Assessment.
Reliability Indices	A module for generating reports from ADMS outage management functions that provide metrics that quantify reliability, including system outage duration (SAIDI), outage frequency (SAIFI) and other industry standard reliability metrics.
Training Simulator	A module that simulates the behavior of the distribution system and other external inputs to an ADMS that mimics real responses to user's actions to assist in the training of distribution operators. Simulated scenarios can include faults, planned outages, and storms. Also called Distribution Operator's Training Simulator (DOTS).
DMS Components	**Distribution Management System Modules/Functionality**
SCADA (D-SCADA)	Distribution Supervisory Control and Data Acquisition - A system of remote control and telemetry used to monitor and control the distribution system and associated feeder automation.
Network Model Validation	A module that manages and validates the electrical model imported from a Geospatial Information System (GIS).
Distribution Power Flow (DPF)	An analysis application that calculates power system operating conditions, including voltage and line flows, given a system model and either real-time measurements or forecast generation and load. For Distribution, the DPF algorithm must also be unbalanced to take into account that the system loads, generation, and model cannot be assumed to be identical on all three phases. Also sometimes called a Dispatcher's Power Flow.
Contingency Analysis	Contingency analysis is a module that evaluates the effects of and calculates any overloads or voltage violations resulting from potential contingency events.
Short-Circuit Analysis	A module that determines the magnitude of short-circuit current at a particular location and type of fault. Short-circuit analysis is used for fault location analysis.
Load Forecasting	A module for calculating the load (and distributed generation) on the distribution system at a given date/time.
Distribution State Estimation	Distribution State Estimation (DSE) - A module that provides estimation of the entire voltage and power flow state of distribution system using real-time measurements from SCADA and pseudo-measurements such as estimated load and distribution generation.
Equipment Management	The tracking and monitoring of distribution system equipment by the ADMS.

Switching Management	A module that assists in the preparation and management of planned and emergency switching sequences. Sometimes also called Switching Order Management (SOM).
Tagging	A function that supports the tracking of tags that are placed on field equipment for the purposes of safety and protection of the field crews while performing work.
Alarm Management	The function of an ADMS that alarms and alerts the distribution operator of abnormal conditions that require attention and/or action to be taken.
Advanced Applications Components	**Advanced Application Components**
FLISR	Fault Location, Isolation, and Service Restoration - A module that automatically determines the location of a fault and rapidly reconfigures the flow of electricity so that some or all customers can avoid experiencing outages.
FLA	Fault Location Analysis - A module that identifies the distance a fault occurs from the source and aids in locating faults.
Dynamic Protection	Advanced Protection Schemes and Device Coordination
IVVC	Integrated Volt-Var Control - A software module that accesses the advanced meter data for both operational/situational awareness and system studies. Also sometimes called Volt-Var Optimization.
DER Optimization	The optimization of the distribution system to support the use of Distributed Energy Resources (DER).

The Companies' proposed ADMS investment is foundational in nature and required to give operators the tools to monitor, control, and automate the evolving distribution grid, including its increasing amounts of customer-owned renewable and distributed resources. Figure 1 illustrates the multiple modules that comprise an ADMS, including the existing DRMS. The catalyst for this ADMS investment is to enable safe and reliable grid operations while increasing both centralized and distributed clean and renewable (but also variable) energy resources in pursuit of Hawaiʻi's RPS. Other utilities, such as Sacramento Municipal Utility District ("SMUD"), Southern California Edison ("SCE"), and Pacific Gas and Electric ("PG&E"), are recognizing the need for the ADMS as a foundational investment.[4,5]

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[4] See Electric Energy Online, "SMUD Selects OSI Technology for a New Advanced Distribution Management System." May 10, 2019: https://electricenergyonline.com/article/energy/category/automation-it/53/699695/open-

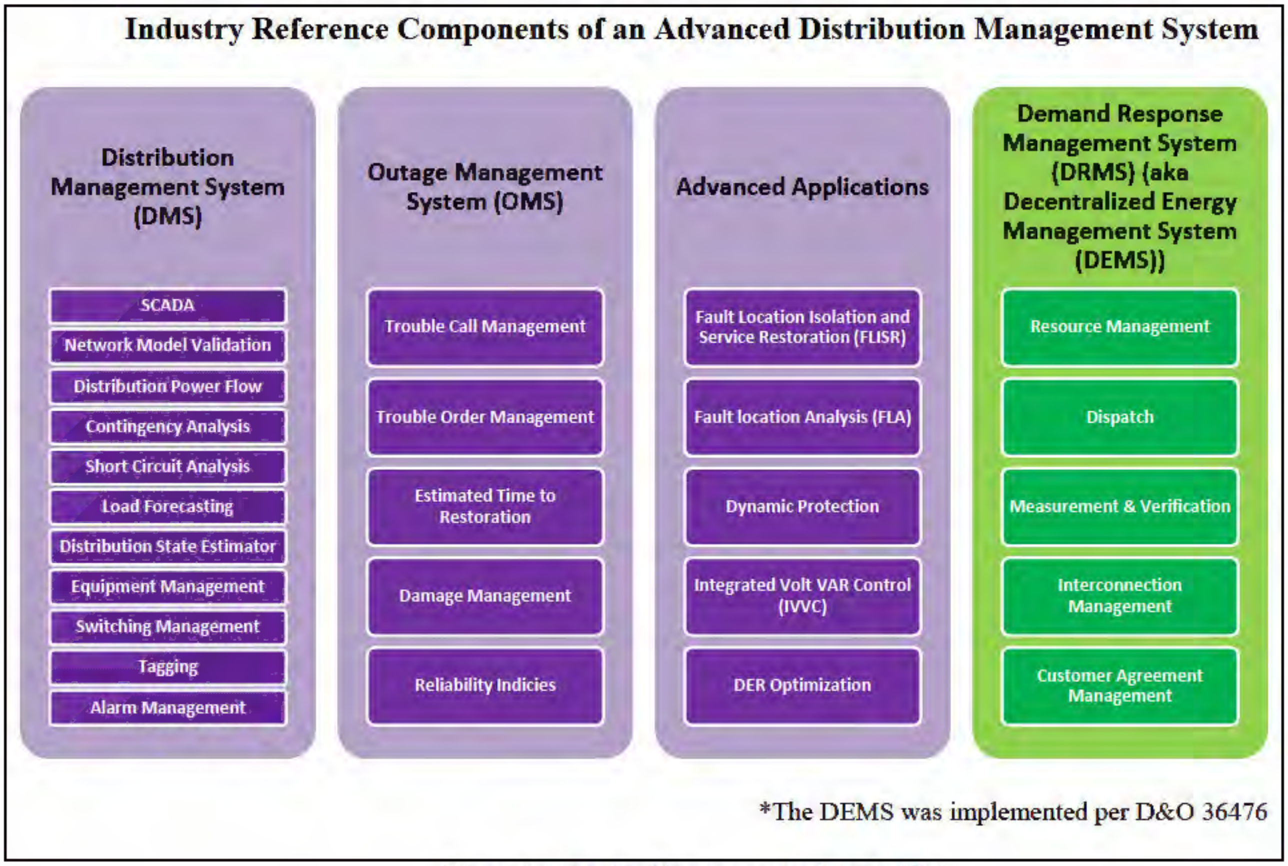

Figure 1 Industry Components of an ADMS

2. ADMS Integration

The proposed ADMS project will replace and expand on the functionality of the current Hawaiian Electric OMS (available for the Hawaiian Electric system only) with a new solution deployed for all three operating Companies. Hawaiian Electric's original OMS was installed in 2006–2007 and has been regularly updated since. However, that system is now over 12 years old and the Companies are seeking to install an OMS that is integrated with an advanced DMS. In today's market, an OMS is now a subset of functionality within an ADMS and the Companies are looking to procure and install a single integrated solution to reduce integration and operation costs and risks with a single vendor solution. Selecting a vendor that has integrated an OMS into its ADMS product introduces less risk than is likely when integrating one vendor's ADMS to another vendor's existing OMS.

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systems-international-inc-osi-smud-selects-osi-technology-for-a-new-advanced-distribution-management-system.html

[5] See Utility Dive, "PG&E may answer the billion dollar grid modernization question." August 26, 2019: https://www.utilitydive.com/news/pge-may-answer-the-billion-dollar-grid-modernization-question/561146/

The ADMS functionality outlined in the previous section and depicted in Figure 1 will depend heavily on the data coming from many different sources. Both software systems, such as the GIS geo-locational data, and field equipment provide data for the ADMS to perform its functions. More information system integration can be found in Exhibit F (*GMS System Architecture and Cyber Security*). As was outlined in the Phase 1 Application,[6] the FAN will ultimately facilitate data transport between field devices and the ADMS, in addition to its other functions. The ADMS will be capable of receiving data from distributed equipment through additional routes, including:

- Through the Companies' Distribution Wide Area Network ("WAN"), which provide SCADA telecommunication into the control centers. The addition of the ADMS will help to maximize the investment in SCADA infrastructure.
- Through leased lines or cellular communications (absent FAN coverage). This option may be used to retrieve data from DA devices that are in between the substation and customers. The limited deployment of field devices to date often utilized this approach to date in absence of a FAN.
- Through the FAN
- Through customer and aggregator telecommunication pathways (e.g. Internet) utilizing a variety of communication protocols. This option utilizes the DEMS and Aggregator data integration to facilitate data transport to the ADMS and/or DEMS.

The ADMS processes all of the distribution monitoring data delivered through these various telecommunication pathways with advanced algorithms to provide situational awareness and tools for the operator, including distribution state estimation, alerts of abnormal conditions, contingency analysis, and recommended switching schemes for load balancing or outage impact minimization.

Integration of the ADMS with the Grid Modernization Phase 1 deployments of advanced meters, MDMS, and the telecom network will enable the sensing capabilities of the advanced meters to notify the Companies when customers are experiencing an outage or abnormal voltage conditions. Integrating these systems will result in faster outage identification and restoration of customer service and improved power quality. For example, advanced meters as well as field sensors can identify an outage in a certain part of the distribution grid. However, in order to properly assess the outage and develop a restoration plan, the ADMS must receive and process data from multiple systems, including MDMS, GIS, and SAP Customer Information System ("CIS"). The ADMS can then analyze available advanced meter and field device data to identify the potential root cause(s) of the outage, which can include identification of both the outage

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[6] See Docket 2018-0141, *Application of Hawaiian Electric Company, Inc., Hawai`i Electric Light Company, Inc., and Maui Electric Company, Limited,* Exhibit G *Telecommunication Network Considerations.*

location and potentially the infrastructure components causing the outage. Switching configurations are then recommended by the ADMS FLISR module to minimize the number of customers impacted by the outage. This power-characteristic data flow information enables improved situational awareness for distribution operators while also providing grid planners more data and confidence to integrate more DG.

Similarly, both advanced meters and grid sensors can identify voltage issues on a distribution feeder. In this instance, the ADMS can be used to coordinate distribution controls to adjust voltage on that feeder. Secondary var controllers and customer-owned advanced inverters can also detect voltage issues and autonomously make var adjustments (with settings managed by the standard interconnection Rule 14H and the participating customers' energy options),[7,8] while load tap changers and phase rebalancing schemes can be enabled by the ADMS.

Integration with the DEMS will afford operators with the status, availability, and control of customer-sited DERs, including DG, storage, controllable loads, and electric vehicles, which will provide operators with a wider array of tools to address issues uncovered with the enhanced situational awareness described above.

The ADMS will also interact with other operational and corporate systems to provide context to the stream of data. For example, the ADMS will integrate with DEMS[9] and each Company's existing Energy Management System ("EMS") to coordinate DER commands and dispatch. It will further integrate with the Companies' existing systems, including:

- SAP Work Orders[10] to facilitate outage restoration processes;
- CIS and GIS for the context about where DER are enabled. This is required for greater context around decision making, faster outage recovery, and load characteristic information;

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[7] See Standard Interconnection Rule 14H: https://www hawaiianelectric.com/documents/billing_and_payment/rates/hawaiian_electric_rules/14.pdf

[8] The term "customer energy options" as utilized in this Application is inclusive of existing and new tariffs and/or programs including Demand Response ("DR") Portfolios (including Time-of-Use ("TOU") and future dynamic pricing) and DER programs. All of these options would be inclusive of any customer-sited resources, including but not limited to photovoltaics ("PV"), distributed storage, and electric vehicles ("EVs").

[9] The DEMS is the name of the product that was approved in the DRMS docket. As the Commission recognized with D&O 36476, the line between DR and DER is nuanced from a policy and program perspective. Similarly, the differentiation between the functions associated with the management software capabilities is nuanced. For the purposes of the Companies' selected architecture, we will be discussing things in terms of DEMS and ADMS. The industry terms of DRMS and DERMS do not comport neatly with the Companies' unique and industry-leading vision wherein customer-cited resources will be relied upon for routine grid operation.

[10] A component of the enterprise management system that facilitates workforce management.

- Phase 1 software systems (telecommunication gateway, meter head-end, and MDMS) to maximize the value of the outage and power characteristic information from the advanced meters.

3. <u>Need</u>

The Companies understand the need to coordinate their near- and long-term plans, as well as provide a clear pathway for how each will work together to address the Commission's Inclinations and achieve the State's RPS. As detailed in the Phase 1 Application, the platform developed and deployed as part of the GMS will enable a grid that can reliably and safely operate with increasing levels of variable renewable resources (as described in the PSIP), enable more customer energy options, and enable exploration of alternatives to meet the needs and expectations of Hawai'i's communities and stakeholders to modernize the electric grid. Collectively, these plans and programs lay out a conceptual framework for the Companies to successfully innovate and achieve necessary enhancements while continuing to pursue advanced technologies that align with customers' needs and interests.

Modernizing Hawai'i's electric grid is foundational to serving customers with affordable, reliable, and resilient electric service while also transforming the system to achieve a renewable energy future that is sustainable and enables customer energy options. Programs and policies are being pursued to progress toward the State's RPS, including requiring 100% of net electricity sales to be provided from renewable energy by the end of 2045.[11] Coupled with the highest penetration of customer-owned PV systems in the country,[12] the Companies' GMS implementation will build the platform to provide customers with improved service, tools and offerings while simultaneously achieving policy milestones.

The sequence of technology investment, starting with GMS Phase 1, leverages functionally mature technologies that are already deployed elsewhere in the industry, including an MDMS and the latest generation advanced meters and FAN.

The OMS component of the ADMS is also a relatively mature technology and Hawaiian Electric has utilized an OMS for over 12 years. However, neither Maui Electric nor Hawai'i Electric Light have installed an OMS yet and this investment will significantly increase their outage response capabilities. The core DMS is also fairly mature with the core components.

However, the ADMS concept of bringing the DMS, OMS and DERMS together as an interoperable platform is a relatively new concept, with the industry putting significant research

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[11] <u>See</u> Hawai'i State Energy Office, Grid Modernization, Renewable Portfolio Standard (RPS) targets, <u>available at</u> http://energy hawaii.gov/renewable-energy/grid-modernization.

[12] In 2017, approximately 27 percent of the Companies' customers' energy needs were met with renewable generation. More than 17 percent of total customers had PV installations by the end of 2017, with additional requests pending approval into the start of 2018.

and development effort into the DERMS component. Hawai‘i's need for a DERMS is evident given the already high level of customer DER interconnected on the island grids and the introduction of new DR programs. As a result, the Companies' DEMS implementation and this requested ADMS implementation are among those leading the nation.

According to the NC Clean Energy Technology Center's 50 States of Grid Modernization report,[13] most states are pursuing grid modernization actions (see Figure 2), with many moving from the policy, studies, and planning stage to deployment (see Figure 3). Due to Hawai‘i's existing adoption of distributed photovoltaic generation (DG-PV) combined with the Hawai‘i RPS goals as well as the fact that the Hawaiian islands are not interconnected with electric transmission lines, the need for grid modernization is arguably greatest in Hawai‘i.

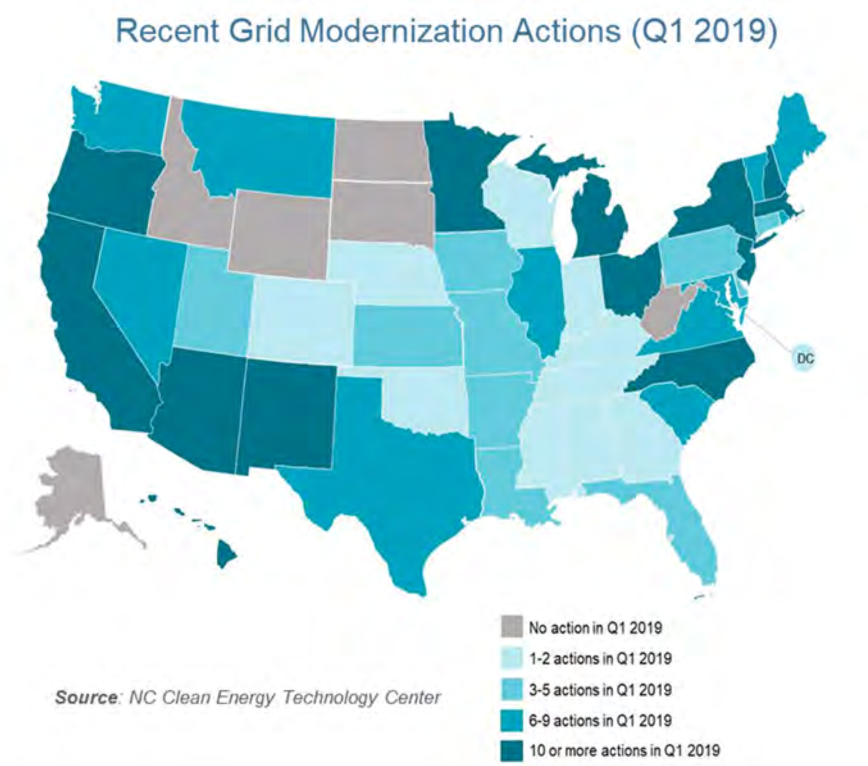

Figure 2

[13] NC Clean Energy Technology Center, *50 States of Grid Modernization Q4 2018 & 2018 Annual Review* (Feb. 2019), available at https://nccleantech.ncsu.edu/wp-content/uploads/2019/02/Q42018-GridMod-Exec-Final2.pdf

Figure 3

The ADMS-phased implementation is being pursued now because:

- ADMS functionality is needed to more effectively and confidently manage the distribution grid.
- Planners require the software tools to make sense of the wide range of data as well as to more accurately and quickly design the system to integrate and rely upon customer-sited PV.
- The vendor community and industry has begun to settle on a standardization of ADMS capabilities, such that the Companies are confident that the solutions will deliver stated capabilities and benefits.

As stated in D&O 34884 in Docket No. 2015-0411 (DRMS Application), the ADMS will facilitate the situational awareness required to make informed decisions about localized DR and DER. In D&O 34884, the Commission recognized that situational awareness is key: "As situational awareness is increasingly made available to HECO Distribution Operators, the

currently procured DEMS will rely on that awareness to maximize the locational value of DERs through targeted dispatch."[14]

More recently, D&O 36476 in Docket No. 2014-0192 (DER Policies) discussed the importance of implementation tools to executing the DER vision: "The success of integrating additional distributed energy resources onto the electric system is highly dependent on coordinating the design and implementation of new grid service programs."[15] The ADMS will help the Companies to expand their distribution awareness and ultimately help them better coordinate a safe and reliable system for customers.

D. ADMS SELECTION PROCESS

The Companies followed a best-practice Request for Proposals ("RFP") competitive process to select from the pool of existing ADMS commercial off-the-shelf software solutions. This RFP process was conducted by a cross-functional team at the Hawaiian Electric Companies (including Hawaiian Electric, Maui Electric, and Hawaiʻi Electric Light) and guided by an external consultant with subject matter expertise in the area of ADMS procurement and ADMS implementation. More specifically, the RFP process followed a formal methodology consisting of the following eleven main tasks:

- Identifying the future state operational needs and use cases[16] for an ADMS;
- Identifying the functional and technical requirements for each ADMS module;
- Reviewing and aligning the requirements with relevant Commission dockets;
- Creating a comprehensive RFP package of documents and issuing the RFP to vendors;
- Bidders conference and question and answer period with vendors;
- Prior to receiving bid responses, defining the decision criteria used for scoring the vendor bids;
- Collecting and scoring vendor RFP responses to short-listed vendors, using an objective methodology consisting of weighted priority evaluation factors;
- Preparing demonstration scripts for the onsite vendor demonstrations;

[14] D&O 34884 at XX.
[15] D&O 36476 at XX.
[16] Refer to Appendix A of this document for a listing and description of the Companies Use Cases.

- Onsite vendor demonstrations and final selection, using a set of prescribed demonstration scripts, a subset of the Companies' GIS data, and test cases that aligned with key operational use cases; and
- Final vendor scoring, selection, and vendor notification.

The RFP process was conducted between the fall of 2018 and the summer of 2019. A detailed description of the RFP process and vendor scoring is provided in Exhibit E (*Request for Proposal*) to the Application.

III. SCHEDULE/OPERATIONAL IMPACTS

A. IMPLEMENTATION ASSUMPTIONS

The Companies identified a variety of potential ADMS implementation schedule scenarios driven by several factors – the installation complexity and change management learning curve of the new ADMS system, as well as the desired and/or dependency sequencing of ADMS module configurations across the Companies' service territories.

The Companies determined that a multi-release implementation schedule would be the most appropriate way to install and configure any new ADMS system. A multi-release implementation allows the Companies to break-up a complex ADMS implementation into manageable projects, which consider (1) the amount of distribution data and connectivity in the GIS, (2) implementing components of an ADMS beginning with more mature products, such as an OMS and then progressing to more advanced applications, and (3) training and change management for System Operation personnel. A multi-release implementation is also consistent with other utilities in the industry, such as SCE and PG&E.[17]

In summary, the Companies will begin their implementation with functionality such as OMS, which has been in practice for many years. The ADMS implementation then progresses to DMS, including distribution SCADA, in conjunction with DA, which then leads to the Advanced Applications, including analytic functions for forecasting, simulating, studying, and optimizing the impacts of different network switching configurations and loading conditions. In the Companies' implementation, integration of DEMS is included from the first release in order to provide some visibility and control of DER from a system-level view. Subsequent releases will provide more localized visibility and control until the last release, which will optimize the use of DER into grid operations.

[17] Utility Dive, "PG&E may answer the billion dollar grid modernization question." August 26, 2019: https://www.utilitydive.com/news/pge-may-answer-the-billion-dollar-grid-modernization-question/561146/

A multi-release approach ensures that the project allows for progressive data clean-up efforts in the "GIS". OMS functions require basic connectivity from a distribution breaker to a circuit down to the transformer connected to a circuit and then a customer connected to the transformer. In the case of Hawaiian Electric, GIS data includes all of this information down to the customer because Hawaiian Electric has an existing OMS. Maui Electric and Hawai'i Electric Light do not currently have customers mapped to distribution transformers. As the advanced analytic functions of an ADMS are enabled, phasing and conductor sizing is also required in the GIS distribution network model. Also, in order to enable the visibility of DER at a local level, accurate DER information, such as DER sizing, output, and type of DER (PV, battery, DR program, etc.), must be incorporated into the DEMS.

Finally, ADMS training for Distribution System Operators for the ADMS is a significant task. A tri-company ADMS implementation will require standardization of processes across all three Companies. Hawaiian Electric System Operators at Hawaiian Electric are already exposed to managing outages using an OMS, but they will require a translation of how outages are managed from the existing vendor to the new ADMS vendor. The Maui Electric and Hawai'i Electric Light System Operators will require training on using an OMS to transition from a more manual outage management process, such as utilizing paper trouble tickets, spreadsheets, and paper maps to using software and electronic maps to manage outages. The training then progresses into how the System Operator will continue to utilize the existing Energy Management System ("EMS") for central generation control and managing system-level conditions and the ADMS for localized distribution controls. System Operations is a 24/7 activity, with personnel managing the grid on all three shifts. Inserting training for the System Operators while staffing for normal and emergency operations will require a coordinated and flexible schedule. A well-trained staff will ensure proper utilization of the variety of features, and capabilities within an ADMS, as well as proper coordination with existing tools like EMS. Implementing the ADMS in a series of releases enables proper training at a pace that System Operators will be able to absorb, retain, and utilize.

The proposed releases for the ADMS project are outlined below.

Release 1 – Deploy basic ADMS features to all Companies and enable system-level DER functions

- Basic OMS features – Replacement of the Hawaiian Electric OMS and installation of OMS at Maui Electric (including Maui, Moloka'i and Lana'i) and Hawai'i Electric Light, including outage tickets, outage call handling, training simulator, mobile client;

- Basic Distribution Management (DMS) features[18] – Distribution SCADA for Hawaiian Electric, switch order handling for Hawaiian Electric, load forecasting, power flow analytics, study mode;
- Basic SCADA features via Inter-Control Center Protocol (ICCP) – telemetry only (no controls) via one-way integrations from existing EMS at each Company;
- Basic demand response (DR) and distributed energy resource (DER) features – to dispatch demand side flexibility programs; and
- Integration with other key enterprise applications – GIS, SAP, AMI/MDMS, and DRMS.

Release 2 – Deploy additional ADMS features and localized DER functions to all Companies

- Advanced features include distribution state estimation (DSE), fault location analysis (FLA), fault isolation and service restoration (FLISR), and direct DER telemetry and control;
- Implementation of Distribution SCADA for telemetry and control of distribution field devices and DERs on the distribution primary-side;
- Additional SCADA integrations with EMS to receive transmission state estimator values and pass controls to EMS managed devices and resources;
- Ability to monitor and adjust the real or reactive power injection of large DER; and
- Integration to wind and solar forecasting services from Underwriters Laboratory (formally known as AWS Truepower) and simulation software models such as Synergi.

Release 3 – Deploy advanced DA and optimize DER features to all Companies

- Advanced DA (distributed automation) integration includes volt/var optimization (VVO) and advanced protection equipment coordination schemes;
- Advanced DER integration includes forward-looking contingency analysis, predictive DER scheduling, and load shedding algorithms;

[18] Hawai‘i Electric Light and Maui Electric’s EMS contain distribution SCADA information down to the distribution circuit breaker. This will remain in the EMS.

- Additional integrations to field volt/var control devices, protection, and switching equipment; and
- Enhanced integration to DRMS to enable status, availability, and control of all customer-sited DERs, including active loads, DGPV, battery controllers, and electric vehicle charging.

1. Evolving Capabilities

The capabilities of the ADMS itself will grow in multiple releases, but they will also grow as more customers enroll in energy options, as further initiatives are executed, and as distribution field devices are deployed over time based on grid needs. Subsequent GMS-related Applications will help to maximize the value and capabilities of the ADMS. As the Phase 1 advanced meters are deployed to more customers, the capabilities of the ADMS, including the insight into DER performance, will expand to new areas. The insight gained from voltage and outage alerts will increase system visibility, providing data to inform distribution grid state estimation. Additionally, the aggregation of interval usage (kWh) and demand (kW) data from advanced meters will refine load forecasts and load profiles for more refined distribution planning, including hosting capacity calculations. While the MDMS serves as the system of record for meter data, the ADMS will receive alerts from advanced meters (including voltage and outage alerts) through the Phase 1 efforts. The ADMS is the system of record for distribution grid data and configuration. The ADMS will receive near real-time telemetry from distribution substation systems and system monitoring data from other field devices to provide grid operators with more data, greater distribution visibility (beyond the substation), and ultimately combine for a state estimation of the distribution system.

B. IMPLEMENTATION SCHEDULE

Pending regulatory approval, the ADMS implementation project is expected to take four years, as reflected in Figure 4. The vendors were asked to submit licensing and configuration bids based on this implementation schedule assumption.

Scope	Current Year	Year 1	Year 2	Year 3	Year 4
Job Analysis Pre-Implementation Work					
Release 1 - Deploy basic ADMS features to all Companies and enable system-level DER functions					
Hawaiian Electric					
Maui Electric					
Hawai'i Electric Light					
Release 2 - Deploy additional ADMS features and localized DER functions to all Companies					
Hawaiian Electric					
Maui Electric					
Hawai'i Electric Light					
Release 3 - Deploy advanced DA and optimize DER features to all Companies					
Hawaiian Electric					
Maui Electric					
Hawai'i Electric Light					

Figure 4 ADMS Implementation Schedule

C. DEPLOYMENT APPROACH

The Companies are assuming a decentralized approach for production operations, where each island control room will have its own ADMS servers with direct communications to local field devices. Non-production servers used for development, testing, and training will be centralized to reduce deployment and support costs. There are significant operational risks and ancillary costs associated with centralizing a mission-critical system like ADMS. The predominant risk is loss of interisland telecommunications, especially in a disaster storm or contingency situation. Operators in the island control rooms must be able to reliably access the ADMS application server, and the ADMS SCADA module must be able to reliably communicate with local field devices on the islands. Therefore, for this reason, the Companies are proceeding with a hybrid approach that decentralizes the critical production operations while centralizing non-production servers.

Generally, the Companies have a strategic objective to standardize and centralize technology systems wherever possible in the interest of reducing information technology ("IT") and operational technology (OT) investment and support costs. For example, by standardizing a

single ADMS solution vendor, the Companies anticipate realization of economies of scale in contracting, customizing, integrating, and maintaining the ADMS platform. Other alternatives would include integrating a new ADMS with the existing OMS for Hawaiian Electric and deploying an ADMS with OMS capability to Hawai‘i Electric Light and Maui Electric. This would require two different OMS model build processes, and additional integration of a new ADMS to an existing OMS for Hawaiian Electric and continued licensing of a separate OMS for Hawaiian Electric, whereas the ADMS for Hawai‘i Electric Light and Maui Electric would include an OMS with the same vendor. Thus, for this project, the Companies are standardizing on a single ADMS vendor, integrating the two existing Energy Management System (“EMS”) (Hawaiian Electric has a different EMS from Hawai‘i Electric Light and Maui Electric) vendors to a single ADMS vendor that can provide OMS, DMS, and Advanced Applications for all three Companies.

IV. BENEFITS

The goal of implementing an ADMS solution in the Hawaiian Electric Companies’ grid control rooms is to provide greater visibility, control, and optimization of the distribution system for more reliable operations of a two-way grid with increased variable renewable DER. Additionally, the solution will improve resilience by allowing operators to quickly adapt to changing grid conditions and rapidly recover following power outages and disruptions by enhancing situational awareness and assisting in restoration triage to recover from events faster. The existing outage management processes will also be modernized to leverage ADMS reporting and automation features that improve customer communications, incident response, and operational efficiency.

The benefits of an ADMS can be summarized in three broad categories -

- Enable Customer Energy Options while advancing Clean Energy Goals
- Improve System Reliability and Customer Communications
- Enhance Operational Resiliency and Efficiency

These benefits are further explored in the following sections. As was discussed with respect to Phase 1, it is impracticable to aggregate GMS implementation benefits for use in a traditional benefit-cost analysis. Indeed, the GMS investments in general, and the ADMS in particular, are foundational to and enable other programs. GMS investments have interrelated and naturally synergistic functions that make it infeasible to determine the cost-effectiveness of each GMS component independently. To compound this, the various benefits enabled by the GMS investments in the accompanying Application (e.g., to support DR and DER) were determined separate from the GMS in other dockets using different methods and assumptions. Because the ADMS is directly traceable to operational decision making, there may be an urge to characterize its benefits solely in the context of improved system and operational performance. As is laid out in the sections that follow, the value derived from the ADMS includes improved situational awareness, safety, outage response, and customer satisfaction. Each of these, and the

trajectory of the Companies' integrated grid planning portfolio, must be considered in the evaluation of this application.

A. <u>COST-BENEFITS CHARACTERISTICS</u>

Recognizing the foregoing, in the GMS, the Companies proposed a holistic cost-effectiveness framework for evaluating the Companies' grid modernization efforts, as summarized in GMS Table 3, reproduced below.[19]

Table 3 Expenditure Categories and Evaluation Methodologies

Expenditure Purpose Category	Methodology
A. Standards and Safety Compliance Grid expenditures required to ensure reliable operations or comply with service quality and safety standards, including both ongoing asset management (replacement of aging and failing infrastructure) and relevant grid modernization technologies	Lowest reasonable cost (similar to least-cost, best-fit used in other jurisdictions)
B. Policy Compliance Expenditures that are needed to comply with state policy goals like the renewable portfolio standard, or direction to interconnect and enable customer adoption of DER	Lowest reasonable cost
C. Net Benefits Expenditures that are not required for standards and safety compliance or policy compliance but would provide positive net benefits for customers	Total resource cost test
D. Self-Supporting Expenditures incurred for a specific customer (e.g., interconnection), with costs directly assigned to those specific customers.	Only for projects that do not shift a cost burden to non-participants—this category does not require benefit-cost justification.

As illustrated in Table 8 of the GMS,[20] the Phase 2 ADMS falls within both the Standards and Safety Compliance and Policy Compliance categories. The lowest reasonable cost evaluation methodology is applicable to both of these expenditure categories. Within Decision and Order 36230, the Commission concluded that "a combination of requirements for competitive procurement, cost recovery caps, and tracking of savings and benefits, have

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[19] <u>See</u> GMS, Section 4.2 (Cost-Effectiveness Framework).
[20] <u>See</u> GMS at 107.

contributed to the commission's determination that MPIR recovery is approved, as described herein."[21]

As described in Exhibit E (*Request For Proposal*), the Companies issued an RFP for the ADMS and the RFPs were developed and evaluated in the context of the GMS and the Companies' broader initiatives. The evaluation of the RFPs included vendor demonstrations and assessment to ensure the solution proposed is consistent with the GMS and will fulfill expectations as the Companies' needs grow. The technology is scalable and compatible with planned investments and architectures, which minimizes risks of stranded investments. Therefore, the solutions obtained through this competitive procurement process will satisfy the Companies' technology needs (aligned to customer and policy objectives) at the lowest reasonable cost.

Importantly, as noted in the GMS, the need for a new holistic evaluation framework has also been recognized in other jurisdictions addressing grid modernization.[22] The Companies highlighted the work of the California Public Utilities Commission ("CPUC") extensively in the Phase 1 Application.[23] The CPUC ultimately issued its final Decision 18-03-023 in March 2018.[24] In that decision, the CPUC examined the four potential options for evaluating the cost-effectiveness of proposed grid modernization investments that were available.

The CPUC decision is complementary with the Department of Energy Distribution System Platform (DSPx) decision guide and cost-effectiveness framework, which outlines recommended application of least-cost / best fit method, traditional customer benefit-utility cost, integrated power system and societal benefit-cost, and real option analysis approaches for grid modernization investments.[25]

This approach is also consistent with the IGP process, which is considering a full range of options to more effectively evaluate the final set of short-term solutions to meet Hawai'i's resource, transmission, and distribution needs. This approach avoids the need to conduct cost effectiveness analysis outside of the resource planning process, as was typically done in the past. IGP will need to learn from and inform other ongoing activities and relevant proceedings,

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[21] See D&O 36230 at 38.

[22] See GMS at Appendix C, Section 2 (*Literature Review of Grid Modernization Evaluation Methodology in other Jurisdictions*).

[23] See Docket No. 2018-0141, *Application of Hawaiian Electric Company, Inc., Hawai`i Electric Light Company, Inc., and Maui Electric Company, Limited* in Exhibit B at 21.

[24] See CPUC, Rulemaking 14-08-013 Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769, *Decision on Track 3 Policy Issues, Sub-Track 2 (Grid Modernization)*, Decision 18-03-023 issued March 26, 2018 (effective March 22, 2018) ("Decision 18-03-023"), at 22-23, available at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M212/K432/212432689.PDF.

[25] See Department of Energy Office of Electricity - Modern Distribution Grid (DSPx) Decision Guide Volume III, Section 3.4.1 Cost-Effectiveness Framework, June 28, 2017, available at https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx.

including programs such as DER, DR, Community-Based Renewable Energy ("CBRE"), Electrification of Transportation ("EoT"), and ongoing grid modernization projects.

B. CUSTOMER CHOICE AND CLEAN ENERGY

Legislative and regulatory direction has encouraged customer energy options in Hawai‘i, including utility and aggregator options with electric system benefits identified by the Commission, and has enabled progression toward clean energy goals and greenhouse gas reductions. The realization of these benefits depends on the development of a modern grid platform to enable Hawai‘i's energy future. The Companies are in agreement with the Commission regarding the need to develop "a grid platform that increases opportunities for distributed technologies, optimizes grid assets to minimize costs, enables customer participation in consumption and energy services, and enhances grid safety, security, reliability, and resilience."[26]

1. Two-Way Grid Visibility

An ADMS solution is critical to the continued addition of DERs with variable and two-way power flows while maintaining system reliability. The ADMS will provide operational visibility, monitoring, and analytics that can facilitate safe, reliable operation with a large amount of energy sources on the distribution system, including potential for reverse power flows (power flowing from the distribution system into the transmission system). The ADMS will combine SCADA (telemetry data) with a geospatial electrical network connectivity model that contains grid assets (physical data) and electrical network details (connectivity data) to accurately calculate real-time power flows. ADMS analytic tools such as Distribution State Estimation and Power Flow Engine will allow operators to estimate the voltages and currents in the system where no direct telemetry exists. ADMS forecasting and study tools can help estimate and potentially avoid future congestion and violation issues. ADMS switching, tagging, and lockout features will help ensure that maintenance and restoration activities are done safely.

The Companies are currently managing the bulk power system without visibility of or control over for the vast majority of distribution resources or the operating state of the distribution network. There are limited tools available, and primarily manual processes are used to operate the distribution system with its unprecedented levels of renewable penetration and widespread reverse power flows. The distributed resources currently have substantial impact on both the distribution system and the bulk grid. This lack of visibility and control over such a major component of the total grid energy is unsustainable. Modernization of the Companies' control rooms is required to support reliable and safe operation of the grid with continued renewable growth on the islands.

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[26] See Docket No. 2017-0226, D&O 35268, issued February 7, 2018, at 26.

2. Coordination of Grid Edge Services

The ADMS will be the coordination hub of a distributed, layered architecture approach for grid management, as presented in the GMS, where the ADMS is supporting the Utility Distribution Operator role.[27] The ADMS, in coordination with the DEMS, would be substituted for the "Utility Distribution Operator" in Figure 5.

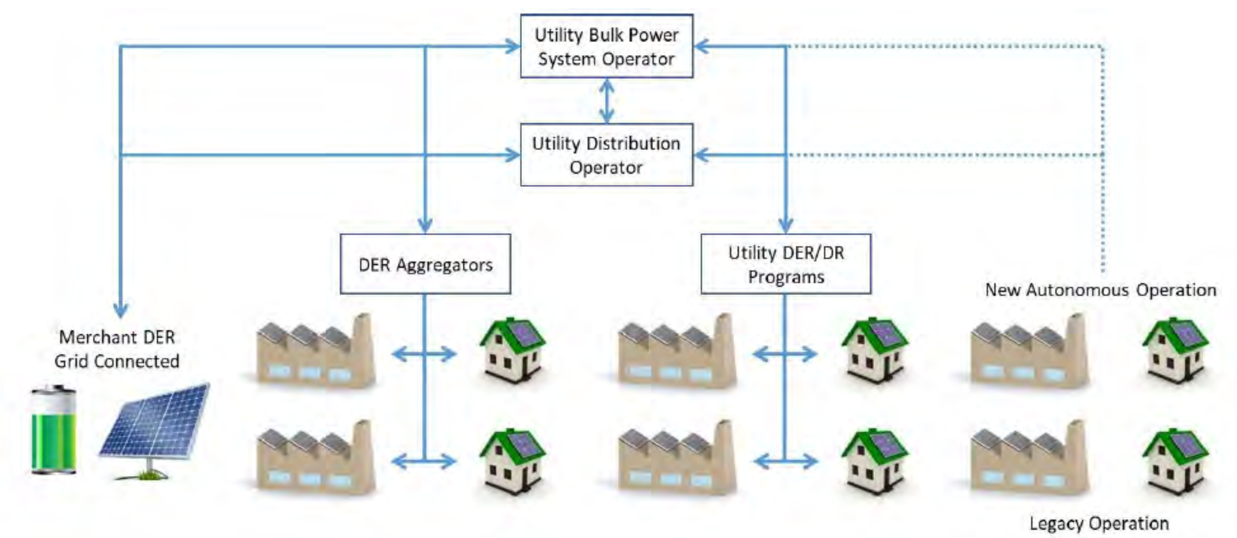

Figure 5 Distributed, Layered Approach for DER

The coordination framework involves managing the operation of grid-connected DER (both controllable systems and autonomously controlled systems) with distribution and transmission systems, as well as grid-scale generation. A layered approach allows coordinated management of the complex security and control interfaces with DER aggregators connected to the DEMS, which participates in specific customer energy options programs and tariffs, and it enables the flexibility to interface with customer systems that already exist, as well as new ones that will be added over time. Without proper coordination, managing this level of complexity across multiple parties will be problematic.

As shown in Figure 6 below, the future state of operations will include the existing Energy Management System ("EMS") for monitoring and controlling system-level components and the ADMS, which will focus on the distribution system. Both of these systems will integrate to behind the meter resources using utility DR and DER demand-side flexibility programs for both bulk system grid services and local distribution grid services.

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[27] GMS at 20.

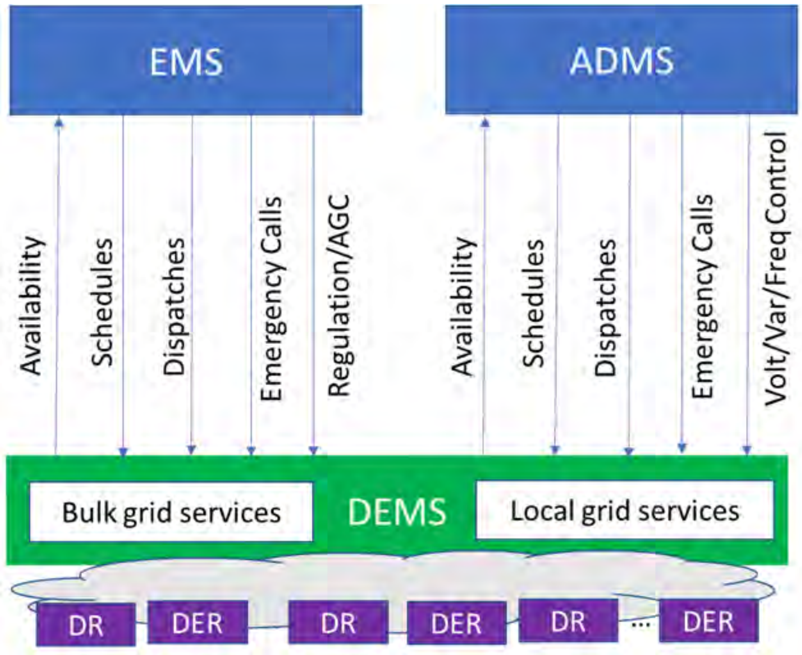

Figure 6 Future State Technical Architecture

The Companies have already made an investment in a DEMS system to enroll and manage demand-side DR/DER resources in incentive programs used for bulk system–level interruptible capacity and ancillary services. The EMS will integrate with the DEMS to dispatch these bulk system grid services. The ADMS will integrate with the DRMS to dispatch demand-side DR/DER flexibility to be used for distribution-level local grid services, distribution network capacity, power quality, and highly surgical ancillary services. The ADMS and DEMS will also interact to ascertain forecasting from distributed assets for inclusion into the load forecasting and advanced power flow forecasting.

3. Non-wires Alternative for Clean Energy Objectives

ADMS is essential to unlocking additional renewable capacity through intelligent software and to deferring capital-intensive wired-based grid upgrades driven by edge-of-grid resources. It enables these non-wires alternative solutions through various strategies that can forecast and avoid network congestion, which stresses aging equipment and creates limit violations that can instigate protection faults. The ADMS enabled strategies include network reconfiguration, VVO, DR, and DER control to actively manage local power balance and quality. The ADMS helps operators predict where stresses or faults may occur, select from the set of available options, and automatically reconfigure the network or utilize demand-side resources.

The ADMS is an integral part of the overall Grid Modernization Strategy. It is the central control system that provides grid edge visibility, control, and optimization of DERs and

field automation. Without the investment in ADMS, customer energy options will be limited, and their respective benefits will not be fully realized.

The ADMS functions not only as the central real-time distribution visibility and control engine, but its capabilities include a planning mode and improved distribution system modeling. These capabilities will assist the Companies in identifying requisite system upgrades and improving the accuracy of the Companies' existing modeling capabilities. The benefit of this is two-fold: (1) more confidently incorporating DER and (2) identifying opportunities for non-wires alternatives, as is being discussed in the Integrated Grid Planning activities, which could function as both the traditional upgrade and could unlock a suite of additional capabilities. The Companies are investigating non-wires alternatives, and the implementation of these alternatives coincides with the anticipated timing of an ADMS implementation. Ultimately, the additional NWA capabilities will improve the overall system capability to incorporate DER, creating a system that can ultimately meet the State's RPS.

C. SYSTEM RELIABILITY AND CUSTOMER COMMUNICATIONS

1. Reduce Outage Restoration Time

The primary purpose and benefit for implementing the OMS module of an ADMS is to reduce outage restoration time, as measured by the System Average Interruption Duration Index ("SAIDI") and Customer Average Interruption Duration Index ("CAIDI"). Improvements in SAIDI and CAIDI are achieved by improving the ability of the control room to identify the location and causes of faults, prioritizing outages based on customers affected, and optimizing the dispatch of field technicians.

ADMS combines these benefits with advanced analytics and SCADA telemetry from the grid edge to further improve outage restoration times. For instance, Fault Location Analysis (FLA) can use impedance measurements and alarms from fault current interrupters to help pinpoint fault locations (and causes) and thus improve crew dispatch. Fault Location, Isolation, and Service Restoration (FLISR) can help create (and automatically perform) switching plans for distribution grid operators to execute in order to restore as many customers as possible by energizing them from alternate electrical paths. Eventually, when the ADMS is more operationally mature, some switching plans could transition from grid operator executed to automated switching controls. The Switch Order Management (SOM) and study features can also help reduce the customer impact of planned outages for system maintenance.

Hawaiian Electric has already realized a normalized five-year average SAIDI of 115 and an improvement trend of 1%–2% annually over the last 10 years, in part from using an OMS software solution in its control room (see Figure 7).[28] In comparison, Maui Electric and Hawai'i

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[28] O'ahu's OMS was installed in the 2006–2007 time frame under Docket No. 2004-131, *Application for approval to defer certain computer software development costs for Item P0000828, Outage Management System, to*

Electric Light have five-year average SAIDIs of 157 and 162, respectively. Deploying OMS functionality to Maui Electric and Hawaiʻi Electric Light should result in a similar performance improvement of 1%–2% per year over the next decade.

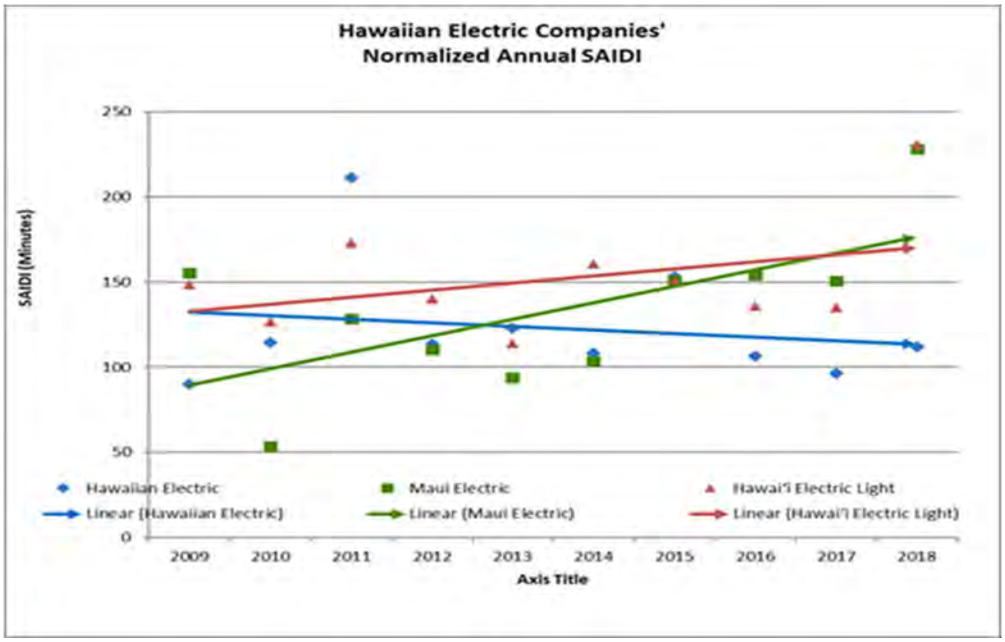

Figure 7 Normalized Annual SAIDI

The pace and realization of these benefits depend somewhat on the deployment and SCADA integration of DA field devices (e.g. Line Sensors, Fault Current Interrupters, Intelligent Switches, other Field Devices), and advanced metering, but the ADMS is the enabling technology that provides operators with visibility and control.

SAIDI Improvement Potential with FLA				
SAIDI sensitivity to FLA SCADA integration intensity levels				
	SAIDI	Feeders integrated, Improvement		
	5-yr Avg	10	25	50
Hawaiian Electric	115	2.13%	5.32%	10.65%
Maui Electric	157	7.33%	18.35%	36.70%
Hawai'i Electric Light	162	5.93%	14.82%	29.65%

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accumulate an allowance for funds used during construction during the deferral period, to amortize the deferred costs, and to include the unamortized deferred costs in rate base.

SAIDI Improvement Potential with FLISR				
SAIDI sensitivity to FLISR DA deployment intensity levels				
	SAIDI	Feeders automated, Improvement		
	5-yr Avg	10	25	50
Hawaiian Electric	115	0.48%	1.19%	2.39%
Maui Electric	157	1.64%	4.11%	8.22%
Hawai'i Electric Light	162	1.33%	3.32%	6.64%

Figure 8 Estimated SAIDI Savings with FLA and FLISR Implemented

The Companies are expecting an additional 1%–2% per year improvement in SAIDI through the combined benefits of FLA, FLISR, and SOM. It will be further supported by future field device deployment.

Automating outage management processes with an ADMS will also have restoration operation benefits to the Companies. The savings are mostly in the form of improved staff productivity in the control room and field crews. Once the ADMS is integrated with advanced metering infrastructure (“AMI”) and SCADA to receive real-time field telemetry, the ADMS will help control room operators more quickly locate, assess, and triage outages with temporary restoration switch plans and crew dispatch instructions. The improved fault location, damage assessment, and partial customer restoration then allow for more precise and optimized field crew dispatching.

2. <u>Reduce Outage Frequency</u>

To a lesser extent, an ADMS can help reduce outage frequency, as measured by the System Average Interruption Frequency Index (“SAIFI”). Improvements in SAIFI are achieved mostly through FLISR by restoring some customers more quickly and converting a percentage of outages into momentary interruptions.[29] ADMS is also an enabling technology to support various Active Network Management (“ANM”), Volt/VAR Optimization (“VVO”), DR, and DER strategies that can forecast and avoid network congestion that stresses aging equipment and violations that create protection faults.

[29] Note this has the consequence of shifting SAIFI numbers into MAIFI - Momentary Average Interruption Frequency Index.

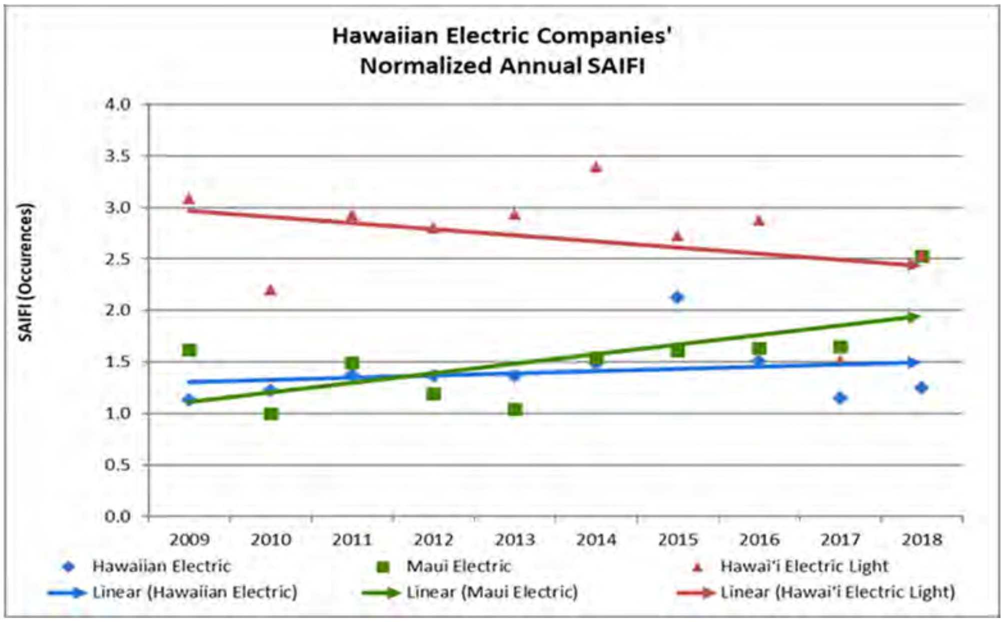

Figure 9 Normalized SAIFI

The pace and realization of benefits depend largely on the current SAIFI on each island (the opportunity for improvement) and the level of corresponding field device investment. For instance, a highly targeted investment in feeder automation at Maui Electric or Hawai‘i Electric Light has a much larger effect on SAIFI than a larger investment at Hawaiian Electric.

SAIFI Improvement Potential with FLISR				
SAIFI sensitivity to FLISR DA deployment intensity levels				
	SAIFI	Feeders automated, Improvement		
	5-yr Avg	10	25	50
Hawaiian Electric	1.51	1.74%	4.33%	8.67%
Maui Electric	1.79	5.98%	14.95%	29.90%
Hawai'i Electric Light	2.61	4.83%	12.08%	24.16%

The Companies expect FLISR to deliver a 5%–20% reduction in SAIFI as supporting DA field devices are deployed and integrated. The cumulative SAIFI improvement potential of using ADMS to execute ANM strategies is more difficult to quantify and isolate from other factors but is estimated at 5% over the next 12 years.

3. **Improved Value of Electric Service**

Reducing outage frequency and duration will have an economic benefit to island electricity customers. For instance, storm-related outages are estimated to cost U.S. customers an average of $25–$75 billion annually.[30] Outages impact factory operations, retail sales, office computers, entertainment, comfort, tourism, and even solar PV production. The value of improved electric service reliability to a geographic region can be estimated with the Department of Energy's ICE Calculator, which estimates the direct customer benefits associated with utility reliability improvements.[31] The ICE Calculator estimates that decreases in SAIDI of 1% or 2% could result in customer savings, as shown in the tables below. Scenario 1 estimates the customer savings for a 1% reduction in SAIDI and Scenario 2 estimates the customer savings for a 2% reduction in SAIDI.

Value of Service Reliability Improvement (SAIDI)					
SAIDI improvements present value, eg through OMS, SOM, FLA, FLISR					
	SAIDI	Scenario 1		Scenario 2	
	5-yr Avg	1%/yr	$k	2%/yr	$k
Hawaiian Electric	115	108	8,383	100	17,442
Maui Electric	157	146	4,298	136	8,251
Hawai'i Electric Light	162	151	5,077	141	9,882
			17,758		35,575
Scenario 1 = Improve 1%/yr after 2025 until 2031 - approx 6%					
Scenario 2 = Improve 2%/yr after 2025 until 2031 - approx 13%					

Value of Service Reliability Improvement (SAIFI)					
SAIFI improvements present value, eg through SOM, FLISR					
	SAIFI	Scenario 1		Scenario 2	
	5-yr Avg	1%/yr	$k	2%/yr	$k
Hawaiian Electric	1.51	1.41	10,242	1.31	22,612
Maui Electric	1.79	1.67	4,965	1.55	9,202
Hawai'i Electric Light	2.61	2.43	11,828	2.27	22,234
			27,035		54,048
Scenario 1 = Improve 1%/yr after 2025 until 2031 - approx 6%					
Scenario 2 = Improve 2%/yr after 2025 until 2031 - approx 13%					

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[30] See LBNL, "Improving the Estimated Cost of Sustained Power Interruptions to Electricity Customers," June 2018.

[31] See https://icecalculator.com.

4. Improve Customer Satisfaction

By implementing an ADMS, the Companies can better meet customer, media, and government expectations of more communication and detailed operations information during normal and emergency situations. Recent years have required frequent emergency incident response events due to tropical storm threats and volcanic eruption impacts, requiring the entire System Operations and Planning divisions to participate in coordinated emergency response and develop communications plans for resilience and restoration.

Hawai‘i Electric Light and Maui Electric do not currently have an OMS solution. This project will include the installation of an OMS, which will enable faster reporting of outage information and enable more informed restoration and incident response to large system disturbances, including coordination with external stakeholders in the community. This will also provide the basis for Hawai‘i Electric Light and Maui Electric to provide up-to-date customer communications. At present, outage information must be compiled and communicated manually after field inspections determine the nature and extent of outages. Hawaiian Electric’s existing OMS solution helps track calls and dispatch crews, but it does not provide the visibility necessary to immediately answer customer questions. This issue may be reflected in the Companies’ customer satisfaction survey results.

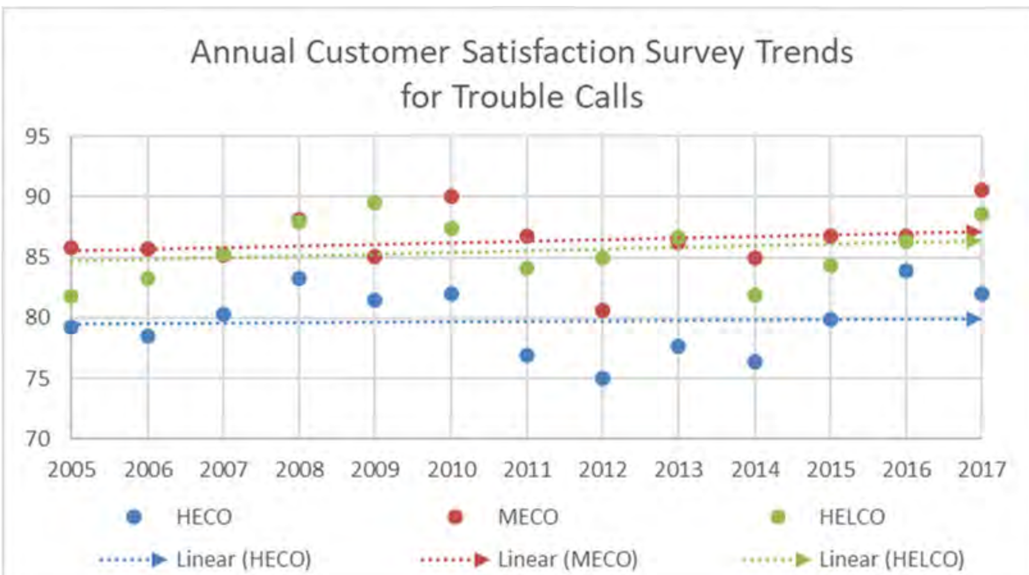

Figure 10

With an ADMS, the Companies will be able to keep customers better informed on system status, restoration times, and actions being taken by the utilities. Operators will also be able to provide immediate answers to customers during regular trouble calls, facilitated by improved visibility of distribution grid conditions and open issues.

The ADMS will also be able to immediately leverage the existing investment in GIS to improve outage location and customer impact estimates. Once deployed and integrated with the

advanced meters and other field sensors, the ADMS will be able to identify and locate outages before customers call. The long-term goal is to support outbound calls to customers with outage notifications and estimated time to restoration information. JD Power reports that proactive notification is a key factor in improving customer satisfaction.[32]

5. Improve Outage Reporting Accuracy

Replacing manual control room processes with an ADMS software solution typically results in more accurate operational reporting. Accurate reporting is critical to building confidence in customer communications and performance-based ratemaking. The current level of *inaccuracy* (and thus the potential for improvement) is difficult to quantify in advance. As an example, the current process relies on customer calls to establish an outage start time, so any delays in reporting the outage would result in underestimating the total outage duration. Generally, the improvements in accuracy manifest in several areas – Estimated Time to Restoration ("ETR") reporting, Hosting Capacity ("HC") reporting, and SAIDI/SAIFI (and other reliability performance metrics) reporting.

The improvement in ETR reporting comes from improved mobile field communications, better damage assessments, and statistically derived crew and damage restoration estimates. The improvement in HC reporting comes from more accurate customer meter-transformer associations and better real-world power quality observations from the distribution grid edge. The improvement in SAIDI, SAIFI, and similar reliability metrics comes from more accurate logging of customer calls, fault alarms, customers affected, and restoration times.

It is important to note that these improvements in reporting accuracy may appear as a temporary deterioration in performance once the ADMS goes into production. This is often due to the prior manual processes masking errors in the process or data, which are exposed and resolved as part of process automation. It may be necessary to adjust or normalize historical reporting to avoid a negative public perception of this side effect.

D. OPERATIONAL RESILIENCY AND EFFICIENCY

1. Enhanced Contingency Control

The ADMS will provide operators with improved visibility, control, and optimization of contingency situations and protection schemes. The ADMS Study and Powerflow functionality allows operators to analyze distribution grid-edge voltage support and to short-circuit current availability. It supports analysis of the impact of potential events. ADMS also provides a platform that can be used to integrate grid-tied storage batteries and local microgrids, which can then be incorporated into restoration and recovery plans. In general, the ADMS will support

[32] See https://www.utilitydive.com/news/for-utility-customer-satisfaction-jd-power-says-communication-control-a/422800/

complex contingency analysis to include consideration of the distribution systems as smaller DER assets increasingly provide a majority of total grid energy.

2. Distributed Control Room Operations Flexibility & Efficiency

The selected ADMS has a modern distributed technology architecture that supports resiliency and flexibility in control room operations. The software allows for secure local and remote access if necessary. These features support resiliency through allowing secure remote access by authorized users for emergencies and emergency backup operations at alternate locations. The mobile features also provide improved situational awareness though enhanced field crew communications for real-time restoration triage, dispatching, and damage assessment.

3. Improved Disaster Recovery

The proposed ADMS deployment architecture includes built-in redundancy of mission-critical components for enhanced operational resiliency in the event of major natural disasters, computer failures, cyber intrusions, or telecom interruptions. This includes a highly available production server environment for the main control rooms, which supports physically separate disaster recovery environments for contingency operations.

The ADMS project will help mitigate resiliency and reliability risks of the renewable energy future with a modern control room solution and architecture that is consistent with the increasing importance of grid-edge DER to overall system power supply and reliability.

4. Control Room Efficiencies

The ADMS will replace manual control room processes at Maui Electric (including Maui, Moloka‘i and Lana‘i) and Hawai‘i Electric Light , i.e., outage tracking using MS Access database, manually performing load calculations for transferring loads, and using MS Word to create hold-off and switching orders, with software automated processes. The resulting work efficiencies will allow operators to focus on higher-value grid planning, monitoring, and optimization tasks. The software also helps reduce operator mistakes that can drive unplanned outages, aborted maintenance activities, or safety issues.

The new ADMS Training Simulator will facilitate operators through simulating events. Using a simulator reduces the learning curve time for new operators for the actions in response to various scenarios and conditions that would otherwise have to be experienced through real-time events. The ability to simulate both daily activities like maintenance switching and seasonal activities like storm restoration provides operators with more hands-on experience, allowing them to be more productive with the software and less likely to make operating errors during all activities.

Furthermore, the use of standardized ADMS software and common training tools will increase the Companies’ ability to share operating lessons and resources across the islands. This will provide the ability to optimize staff skills and balance workloads.

5. Information Technology Efficiencies

The ADMS is a modern software solution for operating a modern grid. In addition to supporting efficiencies in the control room and field services, it is designed for efficient software maintenance, security and resiliency. The system will have automated diagnostics and logging on all its servers, databases, and applications to simplify system health monitoring and issue identification. It will also have user-accessible features for application configuration and administrative features for on-the-fly software upgrades to minimize the cost and downtime of changes.

By selecting a common ADMS solution for all the Companies, the islands will have similar control room software, equipment, and integration architecture. This will provide savings through scale economies of standardized vendor purchase agreements, training, configurations, customizations, integrations, support tools, security frameworks, and communications infrastructure. It will reduce the amount of duplicative work at different operating companies and improve cross-island leverage of technical training, development, and support staff.

The Companies will share development, testing, and training environments. The Companies also plan to share many production components while ensuring system high-availability during emergency conditions requires through the minimum level of necessary redundancy.

E. ALIGNMENT WITH PERFORMANCE BASED RATEMAKING

These benefits are consistent with the guiding principles, regulatory goals, and priority outcomes defined by the Commission in the recently published Performance-Based Ratemaking ("PBR") framework.[33]

The PBR guiding principles include:

- A customer-centric approach,
- Administrative efficiency, and
- Utility financial integrity.

The PBR regulatory goals and corresponding priority outcomes are as follows:

- Enhance Customer Experience
    - Affordability

[33] Docket 2018-0088.

  - Reliability
  - Interconnection Experience
  - Customer Engagement
- Improve Utility Performance
  - Cost Control
  - DER Asset Effectiveness
  - Grid Investment Efficiency
- Advance Societal Outcomes
  - Capital Formation
  - Customer Equity
  - Greenhouse Gas Reduction
  - Electrification of Transportation
  - Resilience

The following table outlines how the ADMS benefits align with the PBR framework.

	Enhance Customer Experience				Improve Utility Performance			Advance Societal Outcomes				
Benefits Breakdown	Affordability	Reliability	Interconnection experience	Customer engagement	Cost control	DER asset effectiveness	Grid investment efficiency	Capital formation	Customer equity	GHG reduction	Electrification of transport	Resilience
Customer Choice And Clean Energy												
Two-way Grid Visibility												
Coordination of Grid Edge Services												
Non-wires alternative for Clean Energy Objectives												
System Reliability & Customer Communications												
Reduce Outage Restoration Time												
Reduce Outage Frequency												
Improved Value of Electric Service												
Improve Customer Satisfaction												
Improve Outage Reporting Accuracy												
Operational Resiliency And Efficiency												
Enhanced Contingency Control												
Distributed Control Room Operations Flexibility & Efficiency												
Improved Disaster Recovery												
Control Room Efficiencies												
Information Technology Efficiencies												

Figure 11

V. EXPECTED INVESTMENT

A. PROJECT COST ESTIMATE

The combined Capital, Deferred, and Expense Costs for the ADMS component of the GMS over its anticipated 2020–2024 implementation are estimated at $45.8 million. This cost estimate aligns with the original estimate for Advanced Operation Systems identified in the August 2017 GMS.[34] The Companies will be requesting recovery of these costs via the MPIR mechanism until such costs are reflected in base rates established in the Companies' respective rate cases.

[34] GMS at 110, Table 9.

The project implementation costs for the ADMS, as the components are placed into service, are broken down by utility and accounting treatment, as shown in Figure 12 and Figure 13.

Company	Account Group	2021	2022	2023	2024	Subtotal
Hawaiian Electric	Capital	[redacted]				[redacted]
Hawaiian Electric	Deferred		[redacted]	[redacted]	[redacted]	[redacted]
Hawaiian Electric	Operations & Maintenance	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hawai'i Electric Light	Capital		[redacted]			[redacted]
Hawai'i Electric Light	Deferred		[redacted]	[redacted]	[redacted]	[redacted]
Hawai'i Electric Light	Operations & Maintenance	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Maui Electric	Capital		[redacted]			[redacted]
Maui Electric	Deferred		[redacted]	[redacted]	[redacted]	[redacted]
Maui Electric	Operations & Maintenance	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Figure 12 – Implementation Costs by Company and by Year

Project	Company	2021	2022	2023	2024	Subtotal
Release 1	Hawaiian Electric	[redacted]	[redacted]			[redacted]
Release 1	Hawai'i Electric Light	[redacted]	[redacted]			[redacted]
Release 1	Maui Electric	[redacted]	[redacted]			[redacted]
Subtotal		[redacted]	[redacted]			[redacted]
Release 2	Hawaiian Electric		[redacted]	[redacted]		[redacted]
Release 2	Hawai'i Electric Light		[redacted]	[redacted]		[redacted]
Release 2	Maui Electric		[redacted]	[redacted]		[redacted]
Subtotal			[redacted]	[redacted]		[redacted]
Release 3	Hawaiian Electric				[redacted]	[redacted]
Release 3	Hawai'i Electric Light				[redacted]	[redacted]
Release 3	Maui Electric				[redacted]	[redacted]
Subtotal					[redacted]	[redacted]

Figure 13 – Implementation Cost by Release and Company

The costs for each of the components are generally broken down into the following six cost categories: (1) internal labor, (2) materials, (3) outside services, (4) other; (5) overheads, and (6) allowance for funds used during construction ("AFUDC") and are displayed in Exhibit G (*GMS Phase 2 ADMS Project Costs*).

The internal labor cost category, which totals approximately [redacted], includes costs for any incremental resources that are required to support the project's deployment. Among other things, the new, internal employees are needed to work on the project so that new processes and capabilities will be maintained and retained within the Companies over the long term. Details of internal labor costs by utility are provided in Exhibit G (*GMS Phase 2 ADMS Project Costs*).

The "other" cost category, which totals approximately [redacted], includes costs for computer hardware as described in Exhibit C (*Accounting and Ratemaking Treatment*).

The outside services cost category, which totals approximately [redacted], includes costs for external vendor staff services to support both software development and related activities, provide training, and data migration. These costs consist of both consultants and the request for proposal ("RFP") awardee that has provided anticipated estimates on labor needs as part of the ADMS deployment and implementation period. The deferred and O&M components are described in Exhibit C (*Accounting and Ratemaking Treatment*).

The overheads cost category, which totals approximately [redacted], was developed using the Companies' budgeting software (UI Planner) and represents an allocation for those Company costs that are not attributed to any particular project or operation but are essential nonetheless. Overheads are comprised of non-productive wages (such as holiday, sick, and vacation pay), employee benefits, payroll taxes, corporate administrative costs, and clearing costs.

The AFUDC for the Project is estimated to be [redacted].

All costs include the relevant general excise taxes ("GET") as applicable at either 4.712% or 4.5%, depending on tax guidelines. GET is mainly applied to equipment, hardware, software, outside services, and maintenance licensing costs.

As discussed in Section III.C above, the Companies are proceeding with a hybrid approach that decentralizes the critical production operations, while centralizing non-production servers used for purposes such as development and testing. Therefore, there will be systems installed at each of the Companies, and there will also be centralized infrastructure shared by the Companies installed at Hawaiian Electric. As described in Exhibit C (*Accounting and Ratemaking Treatment*) to the Application, for the centralized systems, the costs will be allocated between the Companies with 70% recorded to Hawaiian Electric and 15% billed to each of Maui Electric and Hawai'i Electric Light. Otherwise, costs specific to each Company will be allocated 100% to the respective Company.

Training – Pre-Implementation Job Analysis

The Companies are placing an emphasis on training and change management in order to prepare operators to fully utilize the capabilities of the ADMS. The ADMS is one of the foundational tools for the distribution system operators, transitioning from operating system–level devices toward understanding more complex and more abundant paths of electricity flow at the distribution level. Therefore, the Companies will be requesting recovery of these training costs via the MPIR mechanism until such costs are reflected in base rates established in the Companies' respective rate cases. The training costs incurred during the implementation of the project are included in Figures 12 and 13.

Additionally, in preparation for the Project and prior to Commission approval of the Project, the Companies contracted the services of a third-party change management firm to perform a job gap analysis and help identify the training needs. This effort will help the Companies understand the paradigm shift of needed skills and ADMS tasks for System Operators, Trainers, and other System Operation staff. The Job Task Analysis and Job Role Impact Analysis will visually display our risk and change factors and gaps. As a result, the Companies can then develop the necessary competence training and curriculum for using the ADMS in the Companies' very near future. Also, Job Positions may be redefined, which necessitates workforce planning. This is an important step in ensuring the Companies are successful in their implementation and are set up and organized to utilize the software's capabilities as intended. The Companies will be requesting to defer these costs and recover them

via the MPIR mechanism until such costs are reflected in base rates established in the Companies' respective rate cases.

Company	Estimate ($)
Hawaiian Electric	[redacted]
Hawai'i Electric Light	
Maui Electric	
Total	

Figure 14 – Implementation Cost for Pre-Implementation Job Analysis

B. <u>ONGOING OPERATIONS AND MAINTENANCE COSTS</u>

As components of the ADMS system are deployed and modules are put into production, the Companies will also incur new, incremental, ongoing operations and maintenance ("O&M") expenses. The major O&M expense items include Internal Labor (incremental staff requirements for operations and technical support), Vendor Support (annual software licensing, support, and maintenance), and Technical Environment (incremental telecom costs and software/hardware maintenance). The Companies will be requesting to defer and recover these expenses through the MPIR Mechanism, as described in Exhibit C (*Accounting and Ratemaking Treatment*). This will be offset by $[redacted] due to the retirement of the existing OMS at Hawaiian Electric.

Internal Labor and system maintenance costs are expected to ramp up to approximately $1.8 million per year over the course of the project implementation as the solution is put into production across the islands, as shown in Figure 15. This includes approximately $1.4 million for new additional staffing. The exact staffing and enterprise IT cost per Company will depend on the final implementation. However, the Companies will endeavor to reduce the need for additional headcount once we have partially implemented the ADMS with the ADMS vendor because it will provide us with a better idea of the scope of the project and the resources required to operate and maintain the system.

Vendor Support costs are expected to ramp up to $[redacted] per year over the course of the project implementation as software modules are put into production.

Technical Environment costs include two major cost components. The incremental telecom costs are expected to be $[redacted] per year to reserve inter-island bandwidth between control rooms, application servers, and SCADA front-end communication nodes. The incremental software and hardware maintenance costs are more irregular, occurring every three to five years as necessary upgrades to operating systems, database software, server hardware, and storage media.

Company	Description	2021	2022	2023	2024	2025 and Beyond
Hawaiian Electric	Vendor Support	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hawaiian Electric	Telecom Services	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hawaiian Electric	Labor and Labor Related Expense					[redacted]
Hawai'i Electric Light	Vendor Support	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hawai'i Electric Light	Telecom Services	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hawai'i Electric Light	Labor and Labor Related Expense					[redacted]
Maui Electric	Vendor Support	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Maui Electric	Telecom Services	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Maui Electric	Labor and Labor Related Expense					[redacted]
	Total Annual O&M	[redacted]	[redacted]	[redacted]	[redacted]	$1,808,233

Figure 15 Annual Operations and Maintenance Expense

VI. BILL IMPACT

As shown in Exhibit H (*Bill Impact*), the Companies estimate that the average monthly bill impact of the Project for a typical residential customer would be:

- $0.24 at Hawaiian Electric for a customer using 500 kWh, ranging from $0.02 to $0.35;
- $0.76 at Maui Electric for a customer using 400 kWh, ranging from $0.02 to $1.12; and
- $0.72 at Hawai'i Electric Light for a customer using 500 kWh, ranging from $0.02 to $1.07.

VII. CONCLUSION

A modern, reliable and resilient electric grid is needed to provide the foundation for delivering the benefits of the Hawaiian Electric Companies' current and future programs that are enabling customer value and helping to achieve Hawai'i's RPS goals. Beginning with the GMS

Phase 1 Project, the platform developed and deployed as part of the GMS will drive the grid toward achieving more renewable integration, enable more customer energy options, and enable exploration of alternatives to meet the needs and expectations of Hawai'i's communities and stakeholders. Without the investments described in the GMS, customer choice will be limited and already-approved customer energy options and their respective benefits will not be fully realized.

ADMS component of Phase 2 of the Companies' GMS is an integral next step in the Companies' pursuit of the GMS guiding principles of maintaining and enhancing the safety, interoperability, security, reliability, and resiliency of the electric grid, at fair and reasonable costs, while at the same time ensuring optimized utilization of resources and electricity grid assets to minimize total system costs for the benefit of all customers. The ADMS Phase 2 of the GMS consists the implementation of: (1) an OMS used to manage and track outages; (2) a DMS that monitors and controls switching at the distribution level, including distribution SCADA, in conjunction with DA; and (3) "Advanced Applications" — analytic functions for forecasting, simulating, studying, and optimizing the impacts of different network switching configurations and loading conditions.

The benefits of an ADMS solution in the Hawaiian Electric Companies' grid control rooms is to provide greater visibility, control, and optimization of the distribution system for more reliable operations of a two-way grid with increased variable renewable and DER. Additionally, the solution will improve resilience by allowing operators to quickly adapt to changing grid conditions and rapidly recover following power outages and disruptions by enhancing situational awareness and assisting in restoration triage to recover from events faster. The existing outage management processes will also be modernized to leverage ADMS reporting and automation features that improve customer communications, incident response, and operational efficiency.

The total estimated cost of the ADMS Phase 2 Project is approximately $45.8 million, which will result in modest average bill impacts of $0.24, $0.76 and $0.72 for typical residential customers at Hawaiian Electric, Maui Electric and Hawai'i Electric Light, respectively. Although it is impracticable to aggregate GMS implementation benefits for use in a traditional cost-benefit analysis, the ADMS Phase 2 is expected to be cost-beneficial under a lowest reasonable cost analysis and when considered in the context of enabling distributed customer energy options that can provide more cost-effective alternatives to traditional wired investments. For example, the overall GMS implementation has been estimated to be $121 million more cost-effective than the wires alternative estimated in the Companies' PSIPs.

By employing a targeted approach to carrying out the ADMS Phase 2 in an as-needed, where-needed manner, the Project will maximize customer value by supporting energy options and mitigating implementation risks. Over time, as more field devices and advanced meters are deployed in the Companies' service territories, the technologies and systems proposed through the progression of GMS phases will enable system operators to engage with the Companies' DER and DR programs to maintain grid stability, thereby providing further benefits to customers.

Exhibit C

GMS Phase 2 ADMS Application

Accounting and Ratemaking Treatment

ACCOUNTING & RATEMAKING TREATMENT[1]

The Hawaiian Electric Companies[2] propose the following accounting and ratemaking treatment specific to the accompanying application for the Advanced Distribution Management System ("ADMS") component, herein referred to as the Project ("Project"), of the second phase ("Phase 2") of their Grid Modernization Strategy[3] implementation.

The ADMS is a software project consisting of computer hardware and the associated cost of installing the equipment, software, software development, software services, training, and significant interconnection and integration to enable the full benefits of this project and future programs.

The proposed accounting for the ADMS's foundational components generally follows the accounting for capital expenditures and software projects approved by the Public Utilities Commission ("Commission") in the past. In general, the cost of equipment and hardware will be capitalized and their related software and development costs for the project will be deferred. Such treatment is in accordance with Generally Accepted Accounting Principles ("GAAP") and consistent with the Companies' current accounting for such costs. Costs related to software development for Phase 2 and system integration work will follow the Companies' existing accounting policy, which is consistent with the Accounting Standards Codification ("ASC") 350-40, "Internal-Use Software,"[4] of the Financial Accounting Standards Board ("FASB").

The proposed accounting for the ADMS is described below.

I. ADVANCED DISTRIBUTION MANAGEMENT SYSTEM

The cost of the ADMS consists of Capital costs, Deferred costs, and Expense costs.

A. CAPITAL COSTS

The capital costs for the ADMS include the computer hardware and any related installation expenses. As noted in Exhibit B (*GMS Phase 2 ADMS Project Justification with Business Case Support*), the Companies are proceeding with a hybrid approach that decentralizes the critical production operations while centralizing non-production servers used for purposes such as development and testing. Therefore, hardware will be installed at each of the Companies, and centralized infrastructure will be shared by the Companies that will be installed at Hawaiian Electric.

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[1] Note: References to exhibits in this document refer to exhibits included in the accompanying application unless otherwise noted.
[2] Hawaiian Electric, Hawai'i Electric Light and Maui Electric are collectively referred to as the "Hawaiian Electric Companies" or the "Companies."
[3] See "Modernizing Hawaii's Grid For Our Customers," filed in Docket No. 2017-0226 on August 29, 2017 ("GMS," "Grid Modernization Strategy," or "Strategy").
[4] Formally known as Statement of Position 98-1, "Accounting for the Costs of Computer Software Developed or Obtained for Internal Use," issued in March 1998.

The Companies will capitalize the ADMS hardware. The new hardware will be included in plant-in-service upon installation and amortized over five years, beginning January 1 of the year following the installation of the hardware. This is consistent with the Companies' latest Commission-approved amortization period for computer equipment. For the centralized hardware, the amortization of the computer equipment will be allocated between the Companies, with 70% recorded to Hawaiian Electric and 15% billed to each of Maui Electric and Hawai'i Electric Light. Otherwise, hardware specific to each Company will be allocated 100% to the respective Company and amortized accordingly.

Depending on the respective utility, the capital costs incurred outside of rate case test years are proposed to be recovered through the MPIR adjustment mechanism until, effective the month after the go-live date to no later than January 1st of the next annual MPIR filing, such costs are reflected in base rates established in the Companies' respective rate cases, as discussed in Exhibit D (*Interim Recovery*).

B. DEFERRED COSTS UNDER EXISTING ACCOUNTING POLICY FOR SOFTWARE PROJECT COSTS

Consistent with Section II of this exhibit, the Companies propose to account for the ADMS software development costs similar to the accounting for software development costs under FASB ASC 350-40, under which specific implementation costs are deferred and other portions of the implementation costs (such as end-user training and overheads not related to payroll) are expensed as incurred. As allowed under ASC 350-40, the deferred costs would accrue an allowance for funds used during construction ("AFUDC") while the software is under development.

The Companies request to defer costs for the implementation of the ADMS. These include costs for: (1) software purchase and the vendor resources to install and configure the system per the requirements in the ADMS RFP; (2) third-party system integrators (which were not part of the RFP) required due to the complexity of the integration to connect the ADMS with the meter and device head end, energy management, and demand response management system; (3) new, incremental personnel to support the implementation of the Project who will continue to operate and/or maintain the system after go-live; and (4) contract labor resources to supplement the workforce in the testing and validation of the new work processes being implemented. Carrying cost equivalent to the AFUDC rate would be applied to the deferred costs after the software is in use until the deferred costs are included in rate base in determining rates. These deferred costs will be amortized over 12 years, beginning when such amortization is included in rates, and the unamortized deferred costs are included in rate base (see Exhibit D [*Interim Recovery*]).

As noted above, the Companies are proceeding with a hybrid approach that decentralizes the critical production operations while centralizing non-production servers used for purposes such as development and testing. Therefore, there will be software development at each of the Companies as well as some development on centralized functionality that will be performed at Hawaiian Electric.

For any centralized software development, since the systems will benefit all customers, the Companies will allocate the costs among the three utilities such that 70% of the total consolidated costs will be borne by Hawaiian Electric, 15% by Maui Electric, and 15% by Hawaiʻi Electric Light. Otherwise, software development specific to each Company will be allocated 100% to the respective Company.

Depending on the respective Company, the deferred costs are proposed to be recovered through the MPIR adjustment mechanism, effective the month after the go-live date to no later than January 1st of the next annual MPIR filing, until such costs are reflected in base rates established in the Companies' respective rate cases. If the Commission is not inclined to allow recovery of deferred costs through MPIR adjustment mechanism, the Companies propose to recover the deferred costs, with carrying cost equivalent to the AFUDC rate applied until cost recovery through future rate cases (see Exhibit D [*Interim Recovery*]).

C. EXPENSES

The Companies will incur expenses related to the ADMS implementation and post-implementation (e.g., end-user training, incremental labor, project closing costs, support, software upgrades, and maintenance related to the ADMS software) and miscellaneous office supplies. To the extent that these costs are not recovered in current rates, the Companies request to defer these costs and recover these deferred costs through the annual MPIR adjustment mechanism effective January 1 of the subsequent years. These costs will be incurred as soon as each ADMS release is completed and have not been included in existing rate cases.[5,6] If the Commission is not inclined to allow recovery of expense costs through the MPIR adjustment mechanism, the Companies request to defer the costs with carrying cost equivalent to the AFUDC rate applied until cost recovery through future base rates (see Exhibit D [*Interim Recovery*]).

Additionally, prior to Commission approval, the Companies will expend funds for a job analysis and training assessment as part of the change management preparation. To the extent that these costs are not recovered in current rates, the Companies request to defer these costs and recover the deferred cost through the annual MPIR adjustment mechanism effective January 1 of the subsequent year. If the Commission is not inclined to allow recovery of expense costs through MPIR adjustment mechanism, the Companies are requesting to defer the costs with carrying cost equivalent to the AFUDC rate applied until a future rate case and recover the costs in future base rates (see Exhibit D [*Interim Recovery*]).

With request to the requested deferred treatment of the O&M expenses described in this subsection, the Companies note that the Commission has in the past granted deferral accounting treatment in circumstances where the impact on revenue requirements was: (1) the result of events beyond the control of the utilities; and (2) of such magnitude as to warrant relief.

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[5] Docket No. 2018-0368, *Application For Approval Of A General Rate Increase And Revised Rate Schedules And Rules* filed by Hawaii Electric Light Company, Inc.

[6] Docket No. 2019-0085, *Application For Approval Of A General Rate Increase And Revised Rate Schedules And Rules* filed by the Hawaiian Electric Company, Inc.

Importantly, however, in addition to this "beyond control/magnitude" standard, the Commission has acknowledged that:

> [S]ome action taken to advance defined State policy directives, such as the Hawaii Clean Energy Initiative, require atypical but prudent expenses that HECO may otherwise not undertake. Thus, in addition to the beyond control/magnitude requirement stated previously, expenditures associated with advancing the State's defined energy policies may be eligible for deferred accounting treatment.[7]

This ADMS project, including the O&M expenses discussed herein, will advance the State's clean energy goals, including the State's Renewable Portfolio Standards ("RPS") goals. In particular, as the Commission has recognized, a "modernized grid is the 'backbone' necessary to advance the State's Renewable Portfolio Standards ("RPS") goals… and leverage customer-sited resources to assist in grid operation."[8] Therefore, the Companies propose that they be allowed to defer the ADMS O&M expenses incurred prior to, during, and post-implementation of the ADMS project.

O&M costs related to the centralized components of the ADMS, will be allocated amongst the three utilities such that 70% of the total consolidated costs will be borne by Hawaiian Electric, 15% by Maui Electric, and 15% by Hawaiʻi Electric Light. Otherwise, the O&M costs specific to each Company will be allocated 100% to the respective Company.

II. EXISTING ACCOUNTING POLICY FOR SOFTWARE PROJECT COSTS

In Decision and Order No. 18365, filed February 8, 2001, in Docket No. 99-0207 (*Hawaiʻi Electric Light 2000 test-year rate case*), the Commission ruled that preapproval is required before any computer software development project cost can be deferred and amortized for ratemaking purposes. In accordance with the Commission's ruling, the Companies are not deferring and amortizing software development costs for ratemaking purposes unless prior Commission approval is obtained. In addition, in obtaining approval to defer software development costs for the Companies' Customer Information System ("CIS") project in Docket No. 04-0268, the Companies and the Consumer Advocate reached a stipulated agreement, filed on April 13, 2005, and subsequently approved in Decision and Order No. 21798 of said docket. See Attachment 1 for the Companies' existing accounting policy for software project costs.

[7] *See* Order No. 30229, filed February 24, 2012 in Docket No. 2010-0080 (Hawaiian Electric 2011 test year rate case) at 18-19 (footnote omitted).
[8] See D&O 36230 at 54.

Attachment 1

GMS Phase 2 ADMS Application

Exhibit C

Accounting for the Costs of Computer Software

ACCOUNTING FOR THE COSTS OF COMPUTER SOFTWARE DEVELOPED OR OBTAINED FOR INTERNAL USE

(Updated as of April 1, 2006)

Introduction

The following guidelines are provided to assist in the accounting for computer hardware and software costs (acquired, internally developed, or modified solely to meet the entity's needs). This is not meant to be all-inclusive, however we will continue to add or revise the information below, as needed, to provide additional clarification. Questions with respect to these guidelines should be addressed to the Controller or Director of Corporate and Property Accounting.

As a general rule, the costs of computer software, including applicable labor to install the software, and ongoing maintenance are generally charged to the appropriate functional operation and maintenance (O&M) expense account(s), i.e. expensed as incurred, based on the benefiting organization unless:

1. Deferrable software costs have been identified in accordance with applicable accounting standards AND approval has been obtained from the PUC allowing the Company to defer those costs,
2. The computer software is an operating system-type (e.g., Windows XP) software needed to render the new computer hardware "used or useful",
3. Specific overhead costs allowed to be applied to deferrable software costs,
4. AFUDC on deferrable software costs.

Costs for software development projects less than $500K would generally be expensed as incurred. (The $500K threshold refers to the amount of costs that would be deferred during the application development stage described below. It does not refer to the total costs that would be incurred during all three project stages described below.) Please notify the Controller or Director of Corporate and Property Accounting of projects that are less than $500K that will be expensed.

Accounting for Computer Software Guidelines

The costs of software upgrades and enhancements that do not provide additional functionality to the existing software (i.e., modifications to the existing software that would enable the software to perform tasks that it was previously incapable of performing) should be charged to the appropriate functional O&M expense account(s), i.e. expensed as incurred, based on the benefiting organization.

Software that is acquired, internally developed, or modified solely to meet the entity's needs should adhere to the guidance set forth below. In general, software development can be segregated into three stages as follows (also summarized in Exhibit 1):

- Preliminary Project Stage. This stage includes conceptual formulation of software alternatives, evaluation of the alternatives, determination of the existence of needed technology, and final selection of alternatives. Internal and external costs incurred during this stage should be charged as incurred to the appropriate functional O&M expense account(s), based on the benefiting organization, i.e. expensed as incurred.

- Application Development Stage. This stage includes the design of a chosen path, including software configuration and software interface, coding, software installation, and testing, including parallel processing. Certain internal and external costs incurred during this stage should be deferred, including costs to develop or obtain software that allows for access of old data by new systems. Certain applicable overhead and AFUDC costs on the deferrable software costs is also deferred.

  The process of data conversion from old to new systems may include purging or cleansing of existing data, reconciliation or balancing of the old data and the old/new system, creation of new/additional data, and conversion of old data to the new system. Data conversion often occurs during the Application Development Stage; however, data conversion costs, other

than the costs to develop or obtain software that allows for access of old data by new systems, should be charged as incurred to the appropriate functional O&M expense account(s), based on the benefiting organization, i.e. expensed as incurred.

- Post-Implementation/Operation Stage. This stage includes training and application maintenance. Internal and external costs incurred during this stage should be charged as incurred to the appropriate functional O&M expense account(s), based on the benefiting organization, i.e. expensed as incurred.

Further, costs of activities typically associated with business process reengineering should be charged as incurred to the appropriate functional O&M expense account(s), based on the benefiting organization, i.e. expensed as incurred. Note that these activities can occur during any stage above. Examples include the following:

- Preparation of a request for proposal

- Current state assessment – The process of documenting the entity's current business process, except as it relates to current software structure. Often referred to as *mapping, developing an "as-is" baseline, flow charting,* and *determining current business process structure.*

- Process reengineering – The effort to reengineer the entity's business process to increase efficiency and effectiveness. This activity is sometimes referred to as *analysis, determining "best-in-class," profit/performance improvement development,* and *developing "should-be" processes.*

- Restructuring the work force – The effort to determine what employee is necessary.

Accounting for Computer Hardware Guidelines:
Any computer hardware costs incurred relative to the development or acquisition of software should be capitalized following existing Company policies and procedures. Computer operating system software which is acquired in connection with new hardware should be capitalized together with the hardware under the basis that the operating system is needed to deem the hardware "used or useful".

ACCOUNTING FOR THE COSTS OF COMPUTER SOFTWARE DEVELOPED OR OBTAINED FOR INTERNAL USE

(Updated as of April 1, 2006)

Exhibit 1

The following table sets forth the accounting for typical components of a software development project based on whether the item should be expensed, deferred, or capitalized. Please note that some of the activities listed below may occur in multiple stages.

	Internal or Third Party		
Steps	**Expensed**	**Deferred**	**Capitalized**
Business process reengineering and information technology transformation (these activities primarily occur, but not limited to, prior to preliminary project stage):			
Preparation of request for proposal (RFP)	X		
Current state assessment (*i.e., mapping, developing an "as-is" baseline, flow charting, determining current business process structure.*)	X		
Process reengineering (*i.e., analysis, determining "best-in-class," profit/ performance improvement development, developing "should-be" processes.)*	X		
Restructuring work force	X		
Preliminary software project stage activities:			
Conceptual formulation of alternatives	X		
Evaluation of alternatives	X		
Determination of existence of needed technology	X		
Final selection of alternatives	X		
Examples of the preliminary project stage include: • Strategic decisions to allocate resources between alternative projects at a given point in time (e.g., should programmers develop a new payroll system or direct their efforts toward correcting existing problems in an operating payroll system?) • Determine the performance requirements (i.e., what the software needs to do) and systems requirements for the project • Invite vendors to perform demonstrations of how their software will fulfill an entity's needs • Explore alternative means of achieving specified performance requirements (e.g., should an entity	X		

ACCOUNTING FOR THE COSTS OF COMPUTER SOFTWARE DEVELOPED OR OBTAINED FOR INTERNAL USE

(Updated as of April 1, 2006)

	Internal or Third Party		
Steps	**Expensed**	**Deferred**	**Capitalized**
make or buy the software? Should the software run on a mainframe or a client server system?) • Determine that the technology needed to achieve performance requirements exists • Select a vendor if an entity chooses to obtain software • Select a consultant to assist in the development or installation of the software			
Application development stage activities:			
Design of chosen path, including software configuration and software interface		X	
Coding		X	
Installation to hardware		X	
Testing, including parallel processing phase		X	
Data conversion costs: a. Costs to develop or obtain software that allows for access of old data by new system		X	
b. Process of converting data from old to new systems (e.g., purging or cleansing of existing data), reconciliation or balancing of the old data and the new data in the new system, creation of new/additional data, and conversion of the old data to the new system.	X		
Training	X		
Post-implementation/ operation stage activities:			
Training	X		
Application maintenance	X		
Ongoing support	X		
Acquisition of fixed assets:			
Purchase of hardware, office furniture, or work stations, including operating system			X
Reconfiguration of work area - architect fees and hard construction costs			X

Exhibit D

GMS Phase 2 ADMS Application

Interim Recovery

INTERIM RECOVERY[1]

The Hawaiian Electric Companies[2] are requesting interim recovery of certain costs for the Advanced Distribution Management System ("ADMS") component, herein referred to as the Project ("Project"), of the second phase ("Phase 2") of their Grid Modernization Strategy implementation , through the Major Project Interim Recovery ("MPIR") adjustment mechanism ("Mechanism"). In particular, the Companies are requesting recovery of the Capital ("Capital"), Deferred ("Deferred"), and Operations and Maintenance ("O&M") costs ("Costs") of the Project implementation totaling [redacted], [redacted] of pre-implementation O&M expenses, and [redacted] annually in post-implementation incremental O&M expenses: (i) through the MPIR Mechanism until base rates that reflect the revenue requirements associated with the Capital Costs, Deferred Costs, and O&M Costs of the project take effect in a future rate case for each respective company; and/or (ii) to the extent not approved for recovery through the MPIR Mechanism, deferring the costs and including the Project costs in future rate case revenue requirements for each respective Company, with amortization of the Capital and Deferred Costs commencing when base rates that reflect the costs take effect in those respective proceedings.

Pursuant to Section III.B.1.(f) of the MPIR Guidelines, the projects and costs that may be eligible for recovery through the MPIR Mechanism include: "Grid Modernization projects. Projects such as smart meters, inverters, energy storage, and distribution automation to enable demand response." Accordingly, the Companies are requesting to utilize the MPIR adjustment mechanism to recover Project costs in between rate cases.

I. BACKGROUND

In Order 34514, "utilizing the constructive language and provisions in the Joint Proposed REIP Framework, as appropriately amended,"[3] the Commission established the MPIR Guidelines for the MPIR Mechanism. Specifically, the Commission found that:

> [T]he Joint Proposed REIP Framework includes provisions, agreed to by the HECO Companies and the Consumer Advocate, that can serve as guidelines regarding interim recovery of revenues for major projects placed in service between general rate cases, consistent with the purposes for the development of standards and guidelines identified in the [decoupling] Schedule B Order.[4]

The purpose of the MPIR is to provide a mechanism for recovery of revenues for net costs of approved "Eligible Projects" placed in service between general rate cases that are not

[1] Note: References to exhibits in this document refer to exhibits included in the accompanying application unless otherwise noted.
[2] The "Hawaiian Electric Companies" or "Companies" are Hawaiian Electric Company, Inc. ("Hawaiian Electric"), Maui Electric Company, Limited ("Maui Electric") and Hawaiʻi Electric Light Company, Inc. ("Hawaiʻi Electric Light").
[3] See Docket No. 2013-0141, Decision and Order No. 34514, issued on April 27, 2017 ("D&O 34514").See D&O 34514 at 101, para. 139.
[4] Id., para. 138.

provided for by other effective tariffs.[5] "Eligible Projects" are "approved major projects eligible for revenue recovery through the MPIR Mechanism as provided in [the MPIR] Guidelines."[6] As set forth below, Phase 2 qualifies for MPIR recovery.

In Order No. 35026 *Establishing Statement of Issues*, filed November 13, 2017 in Docket No. 2017-0213 (Schofield Generating Station Cost Recovery) the Commission noted:

> Whether or not a project, or an application for interim recovery under the MPIR Guidelines, "meets every standard" or "satisfies all criteria" contained in the Guidelines should not be interpreted either as guaranteeing or as preventing approval of interim cost recovery.[7]

Rather, the Commission will determine on a case by case basis whether it is appropriate, just, and reasonable to exercise its discretion and allow recovery through the MPIR.[8] The Commission further noted that the provisions in the MPIR Guidelines are "guidelines, not to be construed as rules that must be strictly interpreted or deemed dispositive" and further stated that the Commission "may allow considerable latitude in implementing the MPIR Guidelines depending on the circumstances presented in each application."[9]

A. THE PROJECT QUALIFIES FOR MPIR RECOVERY

1. MPIR Recovery of the Project Costs Will Not be Duplicative

Section II.B.2 of the MPIR Guidelines prohibits duplicative cost recovery and states as follows:

> Notwithstanding any other specific provisions in these Guidelines, the MPIR adjustment mechanism shall not collect or recover revenues for costs or expenses recovered through other effective tariffs or revenue recovery mechanisms. The utility shall have the burden of proof in an application for recovery of revenues through the MPIR adjustment mechanism that recovered revenues should not be duplicative.[10]

The Companies' Application does not seek duplicative cost recovery. The Project's costs are incremental costs that are neither included or planned to be included in Hawai'i Electric Light's, Hawaiian Electric's, or Maui Electric's revenue requirements in their 2019, 2020, or 2021 test year rate cases, respectively, nor recovered through any recovery mechanism that is currently in effect. There is one exception, being the pre-implementation costs for Hawaiian Electric. These expenses for Hawaiian Electric were included in the 2020 Test Year Rate Case ;

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[5] See MPIR Guidelines, Section II.A, at 2.
[6] Id., Section I at 1.
[7] See Docket No. 2017-0213, Order No. 35026, issued November 13, 2017, at 7-8.
[8] Id. at 8.
[9] Id. at 8-9 (inconsistency of Application with Guidelines did not prevent consideration of Application).
[10] Id., Section II at 2.

however, if the Commission approves recovery of these costs via the MPIR adjustment mechanism, then these expenses will be removed from the Hawaiian Electric 2020 test year revenue requirements

2. <u>The Project is an Eligible MPIR Project</u>

Pursuant to Section III.B.1 of the MPIR Guidelines, projects and costs that may be eligible for recovery through the MPIR Mechanism are major projects subject to review and approval in accordance with the provisions of General Order No. 7 ("G.O. 7"), including but not restricted to:

(a) <u>Infrastructure that is necessary to connect renewable energy projects</u>. Infrastructure projects such as transmission lines, interconnection equipment and substations, 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) <u>Projects that make it possible to accept more renewable energy</u>. 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) <u>Projects that encourage clean energy choices and/or customer control to shift or conserve their energy use</u>. 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) <u>Approved or Accepted Plans, Initiatives, and Programs</u>. 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.

The Project qualifies under Sections III.B.1(b), III.B.1(c), III.B.1(d), and III.B.1(f) of the MPIR Guidelines.

In particular, the Project is an investment in an Advanced Distribution Management System. The ADMS will build upon the foundational capabilities provided by GMS Phase 1 ("Phase 1"), and will enable enhanced grid control, visibility, and data aggregation functionalities. Like Phase 1, the ADMS is a part of the modern grid platform that will support recent Commission decisions and planning initiatives, such as the approved Distributed Energy Resource ("DER"), Demand Response ("DR") programs, the order for the Companies to submit Electrification of Transportation ("EoT") workplans,[11] as well as the GMS, the Companies' Power Supply Improvement Plan ("PSIP"), and the acceptance of the Companies' Integrated Grid Planning ("IGP") workplans.[12] The Project is therefore eligible under Sections III.B.1.(d) and (f).

In addition, as discussed in Exhibit B (*GMS Phase 2 ADMS Project Justification with Business Case Support*), the proposed project will provide greater visibility, control, and optimization of the distribution system for more reliable operations of a bi-directional power flow grid as an increasing amount of distributed energy resources ("DER") are able to be interconnected to the grid.

The Companies' vision is to use advanced technologies to modernize the existing grid into a platform for enhancing customer value and to provide operational flexibility to integrate more renewables. Combined with Phase 1, the electric grid will evolve to enable and support the integration and optimal utilization of customer resources made available through existing and new customer energy options, as reflected by the renewable generation level projections in the *PSIP Update Report: December 2016* and summarized in the Table 1 below.[13]

[11] See D&O 36448
[12] See D&O 36218
[13] See GMS at 3.

December 2016 PSIP Projections for Demand Response and Distributed Energy Resources		
Generation Source	2017-2021	2022-2045
New Distributed Solar Photovoltaic (DG-PV)	326 MW	2,086 MW
New Customer Self-Supply (CSS) Energy Storage	89 MWh	1,057 MWh
New Demand Response Capacity	115 MW	442 MW
New Demand Response Energy Storage	104 MWh	1,608 MWh

Table 1

The Project will provide the software system for operators, planners, and other systems to make the most of the data provided by distribution investments, including the advanced meters in Phase 1 and future field devices. It will ultimately enable additional distributed renewable energy and allow for more advanced, coordinated, and safe management of the grid as the Companies continue to provide customer energy options.

Stated differently, as discussed in Exhibit B (*GMS Phase 2 ADMS Project Justification with Business Case Support*), the proposed Project will make it possible to operate the grid as more renewable energy is accepted onto the grid through expanded customer participation in DER, DR, and TOU programs. Therefore, the ADMS Project also qualifies under Sections III.B.(b) and (c) of the MPIR Guidelines.

3. The Project Application is Compliant with Section III.C.3. Of the MPIR Guidelines

Section III.C.3.(a) through (j) of the MPIR Guidelines establish certain requirements for applications seeking recovery through the MPIR Mechanism. As discussed below, the Project satisfies each of these requirements.

a. Burden of Proof

Section III.C.3.a of the MPIR Guidelines provides:

> With respect to applications seeking approval to utilize the MPIR adjustment mechanism for cost recovery, the electric utility bears the burden of proof that all project costs proposed for MPIR treatment meet the criteria specified herein and are not routine replacements of existing equipment or systems with like kind assets, relocations of existing facilities, restorations of existing facilities, or other kinds of business-as-usual investments.

Meeting customers' needs and achieving Hawai'i's clean energy goals are not possible with the current grid; *the grid we currently have is not the grid we need*. The purpose of the Project is to build upon the capabilities laid out in Phase 1 by implementing an ADMS . The ADMS is a key component of a modern grid platform (i.e., the grid the Companies need) that will provide value to customers, and will continue to bring additional value when paired with Phase 1 as well as subsequent phases. The Project does not involve "routine replacements of existing equipment or systems with like kind assets, relocations of existing facilities, restorations of existing facilities or other kinds of business as usual investments."

b. G.O. 7 Application

Section III.3.b. of the MPIR Guidelines provides:

> Application for recovery of revenues through the MPIR adjustment mechanism shall be made in conjunction with and as part of an application pursuant to General Order No. 7.

The Companies' application for recovery of revenues through the MPIR adjustment mechanism is submitted in conjunction with and as part of the accompanying Application, which seeks General Order No. 7 ("G.O.7") approval.

c. Costs Net of Benefits

Section III.C.3.c. of the MPIR Guidelines provides:

> Costs recovered through the MPIR adjustment mechanism shall be offset by all known and measurable operational net savings and benefits resulting from the Eligible Projects (including accumulated depreciation and accumulated Deferred income tax reserves, reductions in operating and maintenance expenses, related additional revenues, etc.), to the extent such savings or benefits are not passed on to ratepayers through energy cost or other adjustment clause mechanisms, and to the extent that such savings or benefits can reasonably be quantified. Net savings and benefits shall be offset as they are realized to the extent feasible. 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.

The Companies' proposed ADMS investment is foundational in nature, required to give operators the tool to monitor, control and automate the evolving distribution grid with increasing amounts of customer-owned renewable and distributed resources. The catalyst for this ADMS investment is to enable stable grid operations while increasing both centralized and distributed clean and renewable (but also variable) resources in pursuit of Hawai'i's RPS.

The Benefits of implementing an ADMS can be summarized in three broad categories as discussed in Exhibit B *(GMS Phase 2 ADMS Project Justification and Business Case Support).*

1) Enable Customer Energy Options while Advancing Clean Energy Goals

2) Improve System Reliability and Customer Communications

3) Enhance Operational Resiliency and Efficiency

.

In addition, licensing and maintenance fees from the existing OMS can be discontinued once the ADMS is in place, resulting in an annual savings of [redacted].

Nevertheless, building upon Phase 1, the ADMS intends to enable and assist in realizing the benefits of customer energy options, including customer participation in DR, DER, and TOU programs. Therefore, the Project costs will be offset by the benefits for customers as identified in Exhibit B (*GMS Phase 2 ADMS Project Justification with Business Case Support*).

d. ***MPIR Eligibility***

Section III.C.3.d. of the MPIR Guidelines provides:

> Application for Eligible Projects hereunder shall be made, pursuant to General Order No. 7 procedures. Smaller qualifying Capital projects that are similar in nature or directly related in purpose may be combined or grouped into programs for review in accordance with General Order No. 7 procedures. Applications shall explain each basis for claimed MPIR eligibility, indicating the linkage of the project to any previously submitted planning studies, previously submitted construction budgets and any relevant active Commission dockets. Applications shall also include the information set forth in the following paragraphs (e) through (i).

As discussed above, the Application has been filed pursuant to G.O. 7 procedures; in addition, also as discussed above, and in the Application, the Project supports recent Commission decisions and planning initiatives, including the approved DER and DR programs, as well as the GMS and the Companies' PSIPs. The Project is thus eligible for MPIR recovery for the reasons stated herein and in the Application and other Exhibits thereto.

e. ***Project Business Case***

Section III.C.3. of the MPIR Guidelines provides:

> 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 Companies have provided the detailed business case in Exhibit B (*GMS Phase 2 ADMS Project Justification with Business Case Support*). Additional discussion of the planned execution of investments for Grid Modernization is discussed in Exhibit A (*Grid Modernization Strategy Working Plan*).

f. ***Project Schedule and Budget***

Section III.C.3.f. of the MPIR Guidelines provides:

> A detailed schedule and budget for each element of the planned investment and activities shall be submitted, quantifying any contingencies, risks, and uncertainties, and indicating planned accounting and ratemaking procedures and expected net customer impacts.

Please refer to Exhibit C (*Accounting and Ratemaking Treatment*), and the *Schedule/Operational Impacts* and *Bill Impact* sections in Exhibit B (*GMS Phase 2 ADMS Project Justification with Business Case Support*).

g. ***Criteria for Used and Useful Status***

Section III.C.3.g. of the MPIR Guidelines provides:

> Applications must state the specific criteria that are proposed for determination of used and useful status of the project, to ensure that no costs are Deferred or recovered for new assets that are merely commercially available but are not being used to provide service to ratepayers.

The following criteria for the used and useful status of the Project's various components are further discussed in Exhibit C (*Accounting and Ratemaking Treatment*).

Servers

The Companies will capitalize the hardware (servers) and operating software related to the ADMS upon installation. The servers and operating software are considered turn-key and will be used and useful as soon as they are powered up.

Application Software

The ADMS will be implemented over three releases, each adding additional capabilities and functionality. As each release is completed, or as certain functionalities are made available, the Companies will deem the application software, configuration, and implementation of those ADMS components used and useful upon successful completion of User Acceptance Testing.

h. ***Costs Net of Savings***

Section III.C.3.h. of the MPIR Guidelines provides:

> Recoverable costs shall be limited to the lesser of actual net incurred project/program costs or Commission-approved amounts, net of savings.

The Companies acknowledge that costs recoverable through the MPIR Mechanism shall be limited to the lesser of the actual net incurred project/program costs or Commission-approved amounts, net of savings. Please see subsection A.3.c (Costs Net of Benefits) above, for a discussion of the anticipated costs, net of benefits.

i. Complex Project Treatment

Section III.C.3.i of the MPIR Guidelines provides:

> Complex projects may be eligible for recovery through the MPIR adjustment mechanism when supported by sufficient detailed business case analysis and documentation of reasonably quantifiable expected impacts, costs and benefits resulting from such projects.

As discussed in the Companies' Application and Exhibits, the Project is complex and will affect numerous aspects of the Companies' operations. As noted above, the Project is supported by the detailed business case analysis and documentation set forth in Exhibit B (*GMS Phase 2 ADMS Project Justification with Business Case Support*).

j. Procedural Steps

Section III.C.3.j. of the MPIR Guidelines provides:

> Parties to the proceedings on the applications for recovery of costs through the MPIR adjustment mechanism shall endeavor to complete procedural steps to allow for approval of the application within seven months of the date of the application. The Companies acknowledge that the procedural schedule for MPIR for complex projects may take longer than projects that do not affect numerous aspects of the utility's operations, expenses, or earnings.

The Companies are committed to completing the procedural steps in the instant docket as quickly as reasonably practicable. The Companies also acknowledge, however, that as set forth in Section III.C.3.j., the procedural schedule for applications for recovery of costs through the MPIR for complex projects may take longer than projects that do not affect numerous aspects of the utilities' operations. In particular, as shown in Exhibit B (*GMS Phase 2 ADMS Project Justification with Business Case Support*), the Companies anticipate implementation will begin in 2021, which assumes a 12-month duration for the procedural schedule. Notwithstanding this assumption, consistent with this section, the Companies are amenable to working with the Consumer Advocate to develop a procedural schedule for this docket that enables the procedural steps to be completed within seven months of this filing, to the extent practicable.

B. DURATION OF MPIR MECHANISM FOR GMS PROJECT

1. Pre-implementation

The Companies have contracted the services of a third party change management firm to perform a Job Task Analysis and Job Role Impact Analysis to visually display our risk and change factors and gaps. This will prepare the Companies for the upcoming ADMS system and provide support for change management. They will help the Companies understand the paradigm shift of needed skills and ADMS tasks for System Operators, Trainers and other System Operation staff. As a result, the Companies can then develop the necessary competence training and curriculum for using the ADMS in the Companies' very near future-state. Also, Job Positions may be re-defined and so workforce planning is necessary. The Companies are requesting to defer these costs and recover the deferred costs through the MPIR adjustment mechanism. The expenses for Hawaiian Electric were included in the 2020 Test Year Rate Case[14]; however, if the Commission approves recovery of these costs via the MPIR adjustment mechanism, then these expenses will be removed from the revenue requirement calculation.

Company	Estimate ($)
Hawaiian Electric	[redacted]
Hawai'i Electric Light	[redacted]
Maui Electric	[redacted]
Total	[redacted]

Table 2

2. Implementation

For the Project, the Capital, Deferred, and O&M Costs are requested to be recovered through the MPIR Mechanism, totaling [redacted] for the Project's implementation. These costs are planned to be placed into service at various points during the Project's 2021-2024 implementation period. Table 3 depicts the proposed timing of Capital and Deferred of the year they are placed into service, and the O&M as incurred. Table 4 shows the costs per Release. Attachment 1 is an illustrative schedule describing the MPIR recovery timing and frequency of filings.

[14] See Docket 2019-0085 *Hawaiian Electric Company Inc. 2020 Test Year Rate Case,* HECO-WP-1202B, at 2.

Company	Account Group	2021	2022	2023	2024	Subtotal
Hawaiian Electric	Capital	[redacted]				[redacted]
Hawaiian Electric	Deferred		[redacted]	[redacted]	[redacted]	[redacted]
Hawaiian Electric	Operations & Maintenance	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hawaiʻi Electric Light	Capital		[redacted]			[redacted]
Hawaiʻi Electric Light	Deferred		[redacted]	[redacted]	[redacted]	[redacted]
Hawaiʻi Electric Light	Operations & Maintenance	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Maui Electric	Capital		[redacted]			[redacted]
Maui Electric	Deferred		[redacted]	[redacted]	[redacted]	[redacted]
Maui Electric	Operations & Maintenance	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 3

Project	Company	2021	2022	2023	2024	Subtotal
Release 1	Hawaiian Electric	[redacted]	[redacted]			[redacted]
Release 1	Hawai‘i Electric Light	[redacted]	[redacted]			[redacted]
Release 1	Maui Electric	[redacted]	[redacted]			[redacted]
Subtotal		[redacted]	[redacted]			[redacted]
Release 2	Hawaiian Electric		[redacted]	[redacted]		[redacted]
Release 2	Hawai‘i Electric Light		[redacted]	[redacted]		[redacted]
Release 2	Maui Electric		[redacted]	[redacted]		[redacted]
Subtotal			[redacted]	[redacted]		[redacted]
Release 3	Hawaiian Electric				[redacted]	[redacted]
Release 3	Hawai‘i Electric Light				[redacted]	[redacted]
Release 3	Maui Electric				[redacted]	[redacted]
Subtotal					[redacted]	[redacted]

Table 4

3. <u>Annual Operations and Maintenance</u>

Table 5 shows the estimated annual incremental O&M costs for each Company, which is expected to ramp up to approximately [redacted] per year over the course of the project implementation as the solution is put into production across the islands. However, the Companies will endeavor to reduce the need for additional headcount once we have partially implemented the ADMS with the ADMS vendor because it will provide us with a better idea of the scope of the project and the resources required to operate and maintain the system.

Company	Description	2021	2022	2023	2024	2025 and Beyond
Hawaiian Electric	Vendor Support	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hawaiian Electric	Telecom Services	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hawaiian Electric	Labor and Labor Related Expense					[redacted]
Hawaiʻi Electric Light	Vendor Support	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hawaiʻi Electric Light	Telecom Services	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hawaiʻi Electric Light	Labor and Labor Related Expense					[redacted]
Maui Electric	Vendor Support	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Maui Electric	Telecom Services	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Maui Electric	Labor and Labor Related Expense					[redacted]
	Total Annual O&M	$163,600	$279,200	$321,200	$363,200	$1,808,233

Table 5

Exhibit H (*Bill Impact*) includes the revenue requirements and customer bill impact calculations for the Project. These high-level revenue requirement and bill impact calculations include simplifying assumptions that are discussed further in Exhibit H (*Bill Impact*). In the actual MPIR filing, the revenue requirements will be based on actual costs incurred and detailed classification of the costs in the depreciation and tax calculations. An illustration of the MPIR calculation is provided in Exhibit I (*Hawaiian Electric Companies' Decoupling Calculation Workbook*).

The various revenue requirement components are addressed below:

a. Depreciation assumptions (MPIR Guidelines Section III.C.2.ii) – The MPIR revenue requirement will be based on the depreciation rates in place at the time of filing.

b. Rate of return assumption (MPIR Guidelines Section III.C.2.1) – Eligible costs will include the allowed rate of return or other form of return mechanism (set in the last rate case of the utility where the Project is located) on the investment from the in-service date of the Project. (See Exhibit I [*Hawaiian Electric Companies' Decoupling Calculation Workbook*]). Cost of Capital will be based on the weights and rates in effect for rates at the time of the MPIR filing.

c. Show net of tax 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 Exhibit I [*Hawaiian Electric Companies' Decoupling Calculation Workbook*]). Depreciation and taxes will be based on the rates and regulations in place at the time of filing (when the Project goes into service and in January in the years following).

Gird Mod - Phase 2
Estimated Timeline - Illustration

		Hawaiian Electric	Hawaii Electric Light	Maui Electric
		PRELIMINARY WORK		
2020	various	*Job Analysis - Requesting deferred treatment and recovery via MPIR*		
		RELEASE 1 (2021 & 2022)		
2021	JAN to MAY	MPIR Filing (increase Target Revenues, accrued 1/1/21) *Recovery of:* *2020 actual O&M (portion not in TY)*	MPIR Filing (increase Target Revenues, accrued 1/1/21) *Recovery of:* *2020 actual O&M*	MPIR Filing (increase Target Revenues, accrued 1/1/21) *Recovery of:* *2020 actual O&M*
	JUN to DEC			Estimated 2021 TY Interim Cease MPIR Accrual**
2022	JAN to MAY	MPIR Filing (increase Target Revenues, accrued 1/1/22) *Recovery of:* *2021 Capital Costs (Yr 2);* *Depr & Amort on 2021 Plant Adds^* *& 70% on 2021 centralized Plant Adds^* *2021 actual O&M*	MPIR Filing (increase Target Revenues, accrued 1/1/22) *Recovery of:* *15% Depr & Amort on 2021 centralized Plant Adds^* *2021 actual O&M*	
	JUN	Deferred Software go-live		
	JUL to NOV	MPIR Filing (increase Target Revenues, accrued 7/1/22) *Recovery of:* *2022 Deferred Software (Yr 1)-month following go-live;* *2021 Capital Costs (Yr 2);* *Depr & Amort on 2021 Plant Adds^* *& 70% on 2021 centralized Plant Adds^* *2021 actual O&M*	MPIR Filing (increase Target Revenues, accrued 7/1/22) *Recovery of:* *2022 Deferred Software (Yr 1)-month following go-live;* *2022 Capital Costs (Yr 1);* *15% Depr & Amort on 2021 centralized Plant Adds^* *2021 actual O&M*	MPIR Filing (increase Target Revenues, accrued 7/1/22) *Recovery of:* *2022 Deferred Software (Yr 1)-month following go-live;* *2022 Capital Costs (Yr 1)*
	DEC	HL & ME Deferred Software go-live		
		RELEASE 2 (2023)		
2023	JAN to MAY	MPIR Filing (increase Target Revenues, accrued 1/1/23) *Recovery of:* *2022 Deferred Costs (Yr 2);* *2021 Capital Costs (Yr 3);* *Depr & Amort on 2021 & 2022 Plant Adds^* *& 70% on 2021 centralized Plant Adds^* *2022 actual O&M*	MPIR Filing (increase Target Revenues, accrued 1/1/23) *Recovery of:* *2022 Deferred Costs (Yr 2);* *2022 Capital Costs (Yr 2);* *Depr & Amort on 2022 Plant Adds^* *& 15% on 2021 centralized Plant Adds^* *2022 actual O&M*	MPIR Filing (increase Target Revenues, accrued 1/1/23) *Recovery of:* *2022 Deferred Costs (Yr 2);* *2022 Capital Costs (Yr 2);* *Depr & Amort on 2022 Plant Adds^* *2022 actual O&M (incremental over TY)*
	JUN	Deferred Software go-live		
	JUL to NOV	MPIR Filing (increase Target Revenues, accrued 7/1/23) *Recovery of:* *2023 Deferred Costs (Yr 1)-month following go-live;* *2022 Deferred Costs (Yr 2);* *2021 Capital Costs (Yr 3);* *Depr & Amort on 2021 & 2022 Plant Adds^* *& 70 % on 2021 centralized Plant Adds^* *2022 actual O&M*	MPIR Filing (increase Target Revenues, accrued 7/1/23) *Recovery of:* *2023 Deferred Costs (Yr 1)-month following go-live;* *2022 Deferred Costs (Yr 2);* *2022 Capital Costs (Yr 2);* *Depr & Amort on 2022 Plant Adds^* *& 15% on 2021 centralized Plant Adds^* *2022 actual O&M*	MPIR Filing (increase Target Revenues, accrued 7/1/23) *Recovery of:* *2023 Deferred Costs (Yr 1)-month following go-live;* *2022 Deferred Costs (Yr 2);* *2022 Capital Costs (Yr 2);* *Depr & Amort on 2022 Plant Adds^* *2022 actual O&M (incremental over TY)*
	DEC	HL & ME Deferred Software go-live		
		RELEASE 3 (2024)		
2024	JAN to DEC	MPIR Filing (increase Target Revenues, accrued 1/1/24) *Recovery of:* *2023 Deferred Costs (Yr 2);* *2022 Deferred Costs (Yr 3);* *2021 Capital Costs (Yr 4);* *Depr & Amort on 2021, 2022 & 2023 Plant Adds^* *& 70% on 2021 centralized Plant Adds^* *2023 actual O&M*	MPIR Filing (increase Target Revenues, accrued 1/1/24) *Recovery of:* *2023 Deferred Costs (Yr 2);* *2022 Deferred Costs (Yr 3);* *2022 Capital Costs (Yr 3);* *Depr & Amort on 2022 & 2023 Plant Adds^* *& 15% on 2021 centralized Plant Adds^* *2023 actual O&M*	MPIR Filing (increase Target Revenues, accrued 1/1/24) *Recovery of:* *2023 Deferred Costs (Yr 2);* *2022 Deferred Costs (Yr 3);* *2022 Capital Costs (Yr 3);* *Depr & Amort on 2022 & 2023 Plant Adds^* *2023 actual O&M (incremental over TY)*
		POST GO-LIVE		
2025	JAN until next rate case Interim	MPIR Filing (increase Target Revenues, accrued 1/1/25) *Recovery of:* *2024 Deferred Costs (Yr 2);* *2023 Deferred Costs (Yr 3);* *2022 Deferred Costs (Yr 4);* *2021 Capital Costs (Yr 5);* *Depr & Amort on 2021, 2022, 2023 & 2024 Plant Adds^* *& 70% on 2021 centralized Plant Adds^* *2024 actual O&M*	MPIR Filing (increase Target Revenues, accrued 1/1/25) *Recovery of:* *2024 Deferred Costs (Yr 2);* *2023 Deferred Costs (Yr 3);* *2022 Deferred Costs (Yr 4);* *2022 Capital Costs (Yr 4);* *Depr & Amort on 2022, 2023 & 2024 Plant Adds^* *& 15% on 2021 centralized Plant Adds^* *2024 actual O&M*	MPIR Filing (increase Target Revenues, accrued 1/1/25) *Recovery of:* *2024 Deferred Costs (Yr 2);* *2023 Deferred Costs (Yr 3);* *2022 Deferred Costs (Yr 4);* *2022 Capital Costs (Yr 4);* *Depr & Amort on 2022, 2023 & 2024 Plant Adds^* *2024 actual O&M (incremental over TY)*

Gird Mod - Phase 2
Estimated Timeline - Illustration

		Hawaiian Electric	Hawaii Electric Light	Maui Electric
			Estimated 2025 Consolidated TY Interim - Cease MPIR Accrual**	
2026 to 2030	Annual MPIR Filings		Annual MPIR Filings (increase Target Revenues, accrued 1/1 of each year) Annual Post Go-Live O&M *MPIR recovery of costs not included in base rates*	
			Estimated 2030 Consolidated TY Interim - Cease MPIR Accrual**	
2031 to next TY	Annual MPIR Filings		Annual MPIR Filings (increase Target Revenues, accrued 1/1 of each year) Annual Post Go-Live O&M *MPIR recovery of costs not included in base rates*	

Notes:
Timeline represents the Company's estimated MPIR deliverables and is subject to change.
The Company plans to simplify the MPIR filing to once a year to align with the annual Jan/Feb MPIR adjustment, with the exception of mid-year filings to recover significant capital and deferred costs (estimated for June & December 2022 & 2023).

^ Depreciation/Amortization Expense - Centralized Capital and Deferred Costs will be allocated between Companies on a 70% HE, 15% HL & ME basis, as detailed in Exhibit C of the Application. Assumes consolidated depreciation and amortization rates will be in effect for all Phase 2 projects.

* Incremental O&M Expense - Recovery of incremental O&M expenses after the respective test year will be limited to the increase over the project O&M expense included in the prior test year. Centralized O&M Costs will be recovered on a 70% HE / 15% HL / 15% ME allocation, as detailed in Exhibit C of the Application.

** Illustration assumes a consolidated rate case filing on a 5 year rate cycle from 2025 onward. 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 MPIR filing.

Exhibit E

GMS Phase 2 ADMS Application

Request for Proposal

REQUEST FOR PROPOSAL

This Application is for the Advanced Distribution Management System ("ADMS") component of the Phase 2 of the implementation of the Grid Modernization Strategy ("GMS"),[1] herein referred to as the "Project." This Project is part of the initial groundwork to build the platform needed to create the foundation for a modernized grid that is consistent with the Hawaiʻi Public Utilities Commission's ("Commission") principles.[2] Accordingly, the goal of Phase 2 is to enable advanced distribution monitoring, control, and automation capabilities. To achieve this functionality, the Project Application includes an Advanced Distribution Management System ("ADMS"), which serves as a back office system that can efficiently monitor, visualize, and control distribution grid conditions. The ADMS will also include systems integration to connect the ADMS with existing Energy Management Systems ("EMS"), the recently approved Decentralized Energy Management System ("DEMS"), the Companies' Geographic Information System ("GIS"), which tracks the geographic location of components of the distribution grid, and the Phase 1 MDMS.

The Companies followed a best-practice Request for Proposal ("RFP") competitive process to select from the pool of existing commercial off-the-shelf software solutions. This RFP process was conducted by a cross-functional team at the Hawaiian Electric Companies guided by an external consultant with subject matter expertise in the area of ADMS procurement and ADMS implementation.

I. RFP DEVELOPMENT PROCESS

The ADMS RFP leveraged the significant effort that was invested in the first ADMS RFP, which commenced as part of the Smart Grid Foundation Project ("SGFP") procurement process. The Companies gathered ADMS requirements with the assistance of an external consultant and issued the RFP to various vendors in the industry utilizing the Gartner[3] research of ADMS companies and their market share in the utility market. Eventually the Companies re-evaluated the need and the maturity of the ADMS product and cancelled the first ADMS RFP and it was not included as part of the SGFP Application. The first ADMS RFP process was conducted in 2015.

Following the filing of the GMS, the Companies attended Distributech 2018 in San Antonio, Texas. Distributech is an annual conference held in the continental United States where vendors display and hold sessions about the latest technology for operating and maintaining utility grids and where other utility grid counterparts, including the Companies, present their

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[1] See Docket No. 2017-0226, *Modernizing Hawaiʻi's Grid For Our Customers*, filed August 29, 2017.
[2] See GMS, Section D (Guiding Principles), at 51-52.
[3] https://www.gartner.com/en/about/

latest project endeavors. A group of System Operation personnel attended this conference and observed the advancement in functionality of the ADMS products compared to what was available in the 2015 time frame (current products are available off-the-shelf with less customization required), especially in the ability to address distributed energy resources ("DER"). Thus, along with the GMS filing, a team was formed to begin procuring an ADMS.

Taking some lessons learned from the first ADMS RFP process, the Companies, with the assistance of an external consultant, first gathered information about the current state of outage management and distribution network management operation processes and systems and then identified the future state operational needs and Use Cases[4] for an ADMS. The Companies then refined the functional and technical requirements from the first ADMS RFP to align with the GMS vision, which is for the ADMS to serve as a back office system that can efficiently monitor, visualize, and control distribution grid conditions. The Use Cases helped to define what issues the Companies are currently struggling with in light of the increased penetration of DER and variable and renewable generation. The demonstrations by ADMS vendors at Distributech 2018 helped the System Operation personnel to understand the functional capabilities of today's ADMS systems. In addition, the use of an outside consultant allowed the Companies to understand what features and functions other utilities were using with an ADMS. This approach ensures that the requirements being utilized by the Companies are not unique but is the result of collaboration with other utilities and an articulation of industry need to potential suppliers. More importantly, tailoring the ADMS requirements to Hawai‘i via the Use Cases helps to justify why an ADMS is needed and ensures the ADMS will meet the future needs of the Companies' modernized grid. The ADMS requirements covered all of the topics involved with an ADMS as shown and explained in Section II.C of Appendix B *(GMS Phase 2 ADMS Project Justification with Business Case Support)*.

II. SUMMARY OF THE RFP PROCESS

The schedule below outlines the overall procurement process after the ADMS RFP was developed. The process began with the issuance of RFP materials to bidders in late 2018, followed by a period allowing bidder questions before proposals were due. Shortly after the proposals were submitted by bidders, the Companies held interviews with the bidders for each RFP to clarify all aspects of the bidder response. From there, the proposals were evaluated against a predetermined evaluation methodology, and the bidders went through different stages of evaluations that included an onsite demonstration and a "best and final offer" solicitation to reach the decision for award selection. During each portion of the procurement process, significant due diligence was done in an effort to minimize risk and ensure that the bidder solution aligns with the Companies' vision and anticipated needs.

[4] See Appendix A.

The Companies' goal is to complete vetting, testing, and contract negotiations prior to a Commission decision on the Application for the ADMS component of Phase 2 Grid Modernization, meaning that should the Commission issue a favorable decision approving the Application, procurement and implementation can begin immediately.

The bidder's compliance with the specified requirements, comments, and responses to clarification questions were factored into the technical evaluation. Furthermore, the procurement team sought input on bidder solutions and product specifications in an effort to consider Tri-Company as well cross-organization input.

III. SCHEDULE

The RFP process occurred during the first half of 2019 according to the following schedule:

Activity	Start	Completed
Prepare RFP materials	November 1, 2019	December 27, 2018
RFP Issued	December 28, 2018	December 28, 2018
Question and Answer Period	January 6, 2019	February 18, 2019
Define Decision Criteria	January 1, 2019	February 1, 2019
RFP Responses Due		February 22, 2019
Preliminary Vendor Scoring	February 22, 2019	April 1, 2019
Vendor Shortlist Announcement		April 10, 2019
Prepare Demonstration Scripts	March 1, 2019	April 15, 2019
Demonstration Scripts Issued		April 11, 2019
Vendor On-site Demonstrations	May 6, 2019	June 13, 2019
Final Vendor Scoring	June 15, 2019	July 1, 2019
Reference Checks for Down Selected Vendors	June 13, 2019	June 20, 2019
Vendor Selection		July 15, 2019
Vendor Notification		August 1, 2019

IV. MATERIALS

The complete RFP materials package is included here as Attachment 1.

V. EVALUATION CRITERIA

The Companies evaluate vendors using a Least Reasonable Cost methodology that balanced solution functionality, usability, and total cost of ownership. A vendor-scoring framework was created with the following relative scoring weights –

- [redacted]

- [redacted]
- [redacted]
- [redacted]

These criteria were scored in a series of corresponding evaluation stages.

VI. EVALUATION STAGES

Vendor scoring was conducted in a series of stages to gradually reduce the field of candidates.

- **Stage 1** [redacted]
- **Stage 2** [redacted]
- **Stage 3** [redacted]
- **Stage 4** [redacted]

Stages 1 and 2 required an extensive evaluation of the vendor's response from a cross-functional (Operational Technology, Information Technology, and Procurement) and tri-company evaluation team that read every line of information, especially in the Detailed Functional and Technical ADMS Requirements, Technical and Cybersecurity Requirements, and Detailed Cost and Staffing Model as shown in Attachment 1. [redacted] Stage 3 required on-site vendor demonstrations, which consisted of three days of vendor demonstrations, in which vendors followed a well-developed script using the Companies' GIS extract information to display their capabilities. Topics outlined in Section II.C of the Business Case (all topics of an ADMS) were

covered by the vendor. In most cases the vendor brought a team of about 10–16 people (some by phone and some on-site). The evaluation process required a lot of dedicated time by the System Operation personnel over a period of 8 weeks; however, the ADMS is a critical system for the continued and future incorporation of DER, variable and renewable technology, therefore the time invested into evaluating the ADMS RFP is important. A Final Decision was based on the highest combined Total Score across all Stages.

VII. VENDOR SCORING AND DECISIONS

The following table summarizes the actual vendor scoring and decisions at each stage.

[redacted]

VIII. FINAL DECISION

The selected vendor, Open Systems International ("OSI"), had the highest combined Total Score across all criteria. [redacted] f the final candidate solution options, the selected vendor provided the best total cost of ownership. The Companies agree the selected vendor is the Least Reasonable Cost solution.

Appendix A – Use Case for ADMS

Use Case Titles
Use Case 1 – SCADA Events and Alarming
Use Case 2 – SCADA Control
Use Case 3 – SCADA Control System
Use Case 4 – Outage Management
Use Case 5 – Detect Restoration Issues
Use Case 6 - Switching
Use Case 7 – Fault Location Analysis
Use Case 8- Fault Location Isolation System Restoration
Use Case 9 – State Estimation
Use Case 10 – Operations Powerflow Studies
Use Case 11 – Volt Var Optimization
Use Case 12 – Load Management
Use Case 13 –Forecasting
Use Case 14 – Dynamic Relay Settings
Use Case 15 – EMS Coordination
Use Case 16 – GIS Updates
Use Case 17 – Planning and Coordination
Use Case 18 – CIS Updates
Use Case 19 – Asset Management Coordination
Use Case 20 – DRMS Coordination and Integration
Use Case 21 – Go Live Preparation

Use Case 22 – High Availability
Use Case 23 – Disaster Recovery
Use Case 24 – Security Event
Use Case 25 – System Update, Patch and Upgrades
Use Case 26 - Reporting
Use Case 27 – Operations Dashboards
Use Case 28 – Training Simulator

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Exhibit F

GMS Phase 2 ADMS Application

System Architecture and Cyber Security for Grid Modernization

Table of Contents

I. SYSTEM ARCHITECTURE FOR GRID MODERNIZATION

On August 29, 2017, the Hawaiian Electric Companies[1] submitted their Grid Modernization Strategy ("GMS"),[2] which was approved by the Commission.[3] The GMS outlined the Companies' vision for the future cyber-physical grid platform that will help lay the foundation for achieving the goal of Hawai'i's renewable portfolio standards ("RPS") of generating 100% renewable energy by 2045.[4] The GMS was created by leveraging input from customers, stakeholders, and the vendor community and outlines plans for grid- and customer-facing technologies enabled by a modern telecommunications network. This combination of input, when applied to the current and future needs of Hawai'i's grids, resulted in a logical and sequential strategy for the Companies' future, flexible grid platform.

The GMS Phase 1 Platform implementation[5] is focused on providing more granular customer data to empower customers to pursue energy options while also providing more insight into the state of the distribution grid. The combination of advanced meters, field area networks ("FANs"), and meter data management systems ("MDMS") provide a foundational and empowering investment in the capabilities of the grid to meet the collective needs and expectations of customers, stakeholders, the Commission, and the Companies. Specifically, advanced meters will be deployed to customers enrolling in energy options[6] such as distributed energy resource ("DER") and demand response ("DR") programs, where both interval meter data and more frequent meter reading are necessary to properly manage the parameters specified in the tariff structures for these programs. In addition, the advanced meters will be the new standard meter for customer meter replacements as well as new construction. The Companies have begun to implement Phase 1 per D&O 36230 and are ready to pursue the advanced distribution management system ("ADMS") component of Phase 2 in a sequential and logical order to build capabilities over time. The GMS Phase 2 ADMS implementation will provide the software system for distribution operators and planners and other roles to make the most of the data and control enabled by distribution investments, including the advanced meters from Phase 1. The GMS investments will ultimately enable additional distributed renewable energy and allow for more advanced, coordinated, and safe management of the grid as the Companies continue to enable customer energy options.

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

[2] See Docket No. 2017-0226, *Modernizing Hawai'i's Grid For Our Customers*, or Grid Modernization Strategy ("GMS") filed August 29, 2017.

[3] See Docket No. 2017-0226, Decision and Order No. 35268, issued February 7, 2018.

[4] See Hawai'i Revised Statutes § 269-92.

[5] See Docket No. 2018-0141, Decision and Order No. 36230, issued March 25, 2019.

[6] Customer energy options include but are not limited to Demand Response ("DR") and Distributed Energy Resources ("DER") programs, Time-of-Use ("TOU") rates, and capabilities to provide customers insight to better manage their energy usage.

A. BUILDING A MODERN GRID

Components of an ADMS— including a Demand Management System ("DMS"), Outage Management System ("OMS"), supervisory control and data acquisition ("SCADA") system, network model, advanced protection, power quality analysis, fault analysis, DER & load forecasting, and power flow analysis—are core foundational components of a next generation distribution system platform. Figure 1 is a re-creation of the U.S. Department of Energy ("DOE") Modern Distribution Grid (DSPx) Report, Volume III,[7] "Figure 8: Next Generation Distribution System Platform & Applications," which was also included in the GMS as Figure 4. This graphic demonstrates how the advanced grid and customer applications are built on top of core components. This foundation provides the basis to enable grid edge and customer applications.

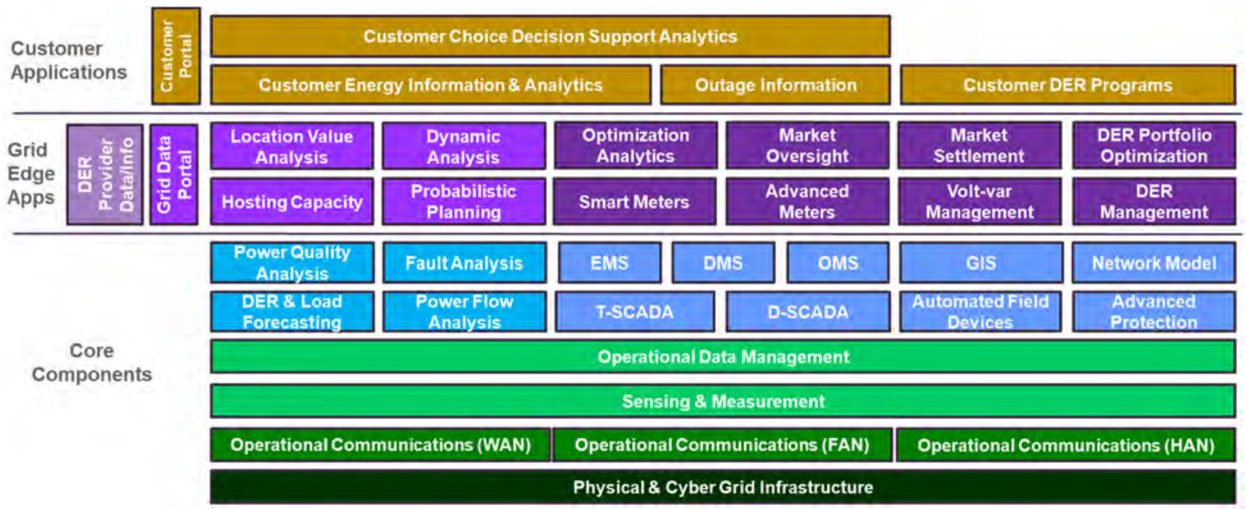

Figure 1

Figure 2 is a re-creation and elaboration of GMS Figure 9, "Current Status of the Companies' Customer-Facing and Advanced Grid Technologies." The color gradient in each of the components illustrates the relative level of Hawaiian Electric Companies' capability in 2017, at the time of the GMS filing.

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[7] See U.S. Department of Energy next generation distribution system platform initiative (aka Next-Generation Distribution System Platform (DSPx) Project), Modern Distribution Grid Report, Volume III, available at https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx.

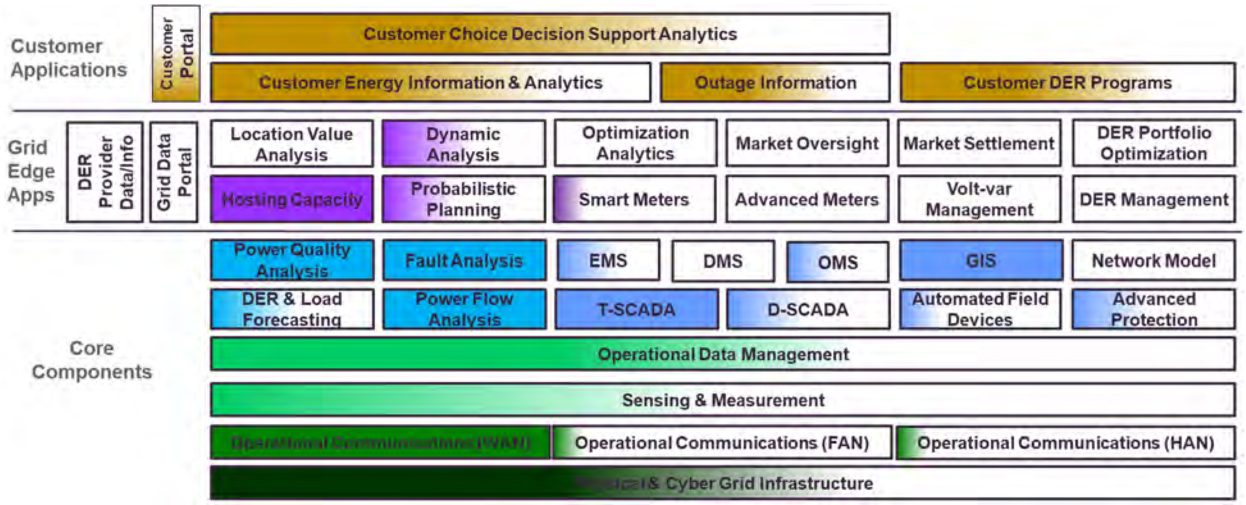

Figure 2

The implementation of GMS Phase 1 and Phase 2 in combination with the capabilities gained through the decentralized energy management system ("DEMS")[8] has systematically gained many of the "Next Generation Distribution System Platform & Applications" identified in the DOE's DSPx initiative. Figure 3 repeats Figure 2, with the addition of color-coded outlines to identify the DSPx components that align with GMS components and the DEMS. Note that the ADMS component of Phase 2 will provide multiple components of the DSPx modern grid platform. In addition, the ADMS is a key component of achieving the items indicated as "Enabled by ADMS." However, unlike the components outlined in solid red, the components shown in dashed red lines require incremental, rather than up-front, investment and deployment of field devices to provide the requisite distribution monitoring, control, and automation to achieve full functionality over time and ultimately provide additional customer energy options.

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[8] See Docket Nos. 2015-0411 and 2015-0412. The DEMS is the name of the product that was approved in the DRMS docket. As the Commission recognized with D&O 36476, the line between DR and DER is nuanced from a policy and program perspective. Differentiating between the functions associated with the management software capabilities is similarly nuanced. For the purposes of the Companies' selected architecture, we will be discussing systems in terms of DEMS and ADMS. The industry terms DRMS and DERMS do not comport neatly with the Companies' approach, wherein customer-cited resources will be relied upon for routine grid operation.

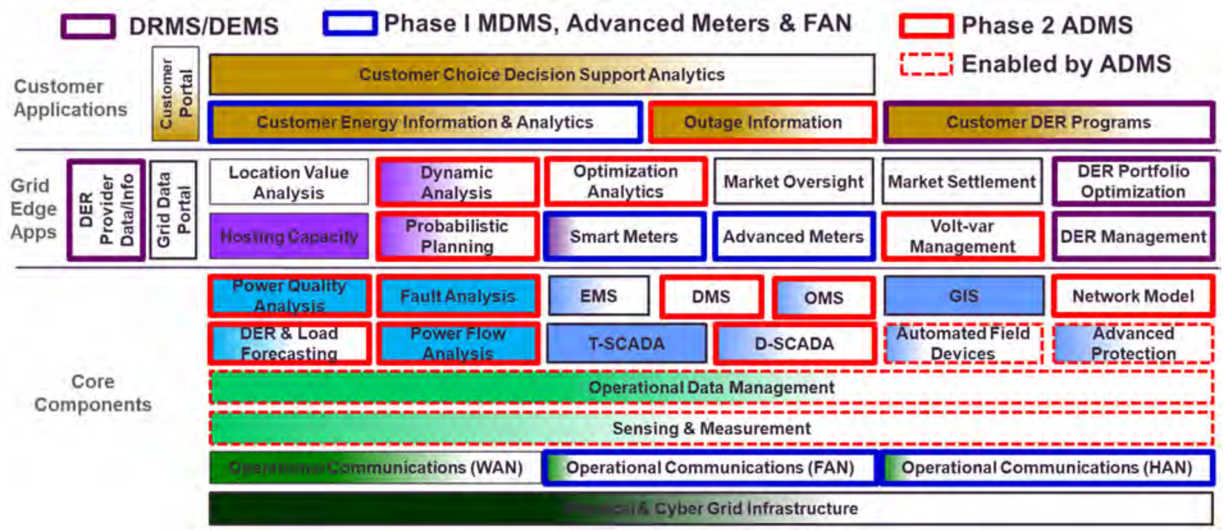
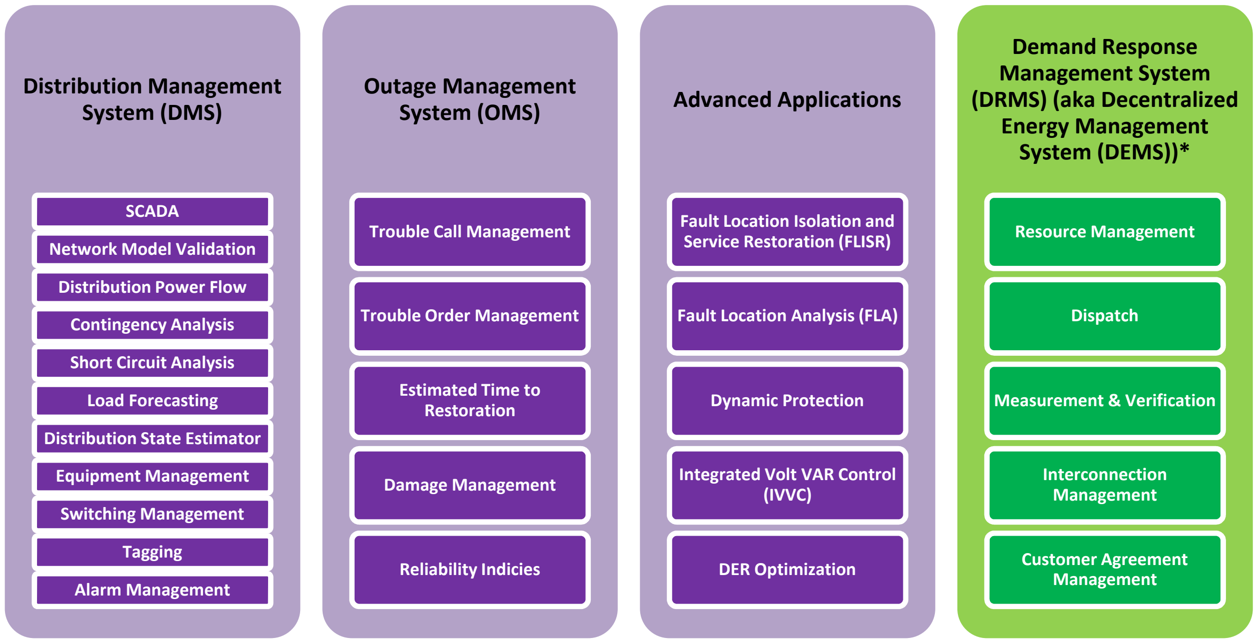


Figure 3

B. COMPONENTS OF AN ADMS

The proposed Phase 2 investment in an ADMS provides the foundational tools operators require to monitor, control, and automate the evolving distribution grid with increasing amounts of variable renewable and distributed resources. Figure 4 illustrates the multiple modules that comprise an ADMS. The catalyst for this investment in an ADMS is to maintain stable grid operations while increasing both centralized and distributed clean and renewable (but also variable) resources in pursuit of Hawai‘i’s RPS while lowering greenhouse gas emissions. A detailed description of each of these ADMS modules is included in Exhibit B (*GMS Phase 2 ADMS Project Justification with Business Case Support*).

Industry Reference Components of an Advanced Distribution Management System



*The DEMS was implemented per D&O 36476.

Figure 4

The ADMS will also interact with other operational and corporate systems to provide context to the stream of data. For example, the ADMS will integrate with the DEMS system and each Company's existing energy management system ("EMS") to coordinate DER commands and dispatch. As depicted in Figure 5, the ADMS will integrate with the Companies' existing systems, including the following:

- SAP Work Orders to provide field crew instruction for outage restoration processes and other troubleshooting of field work
- SAP customer information system ("CIS") and geographic information system ("GIS") to provide context about where customers and infrastructure components are located on the distribution grid
- GMS Phase 1 meter head-end, and MDMS to receive and utilize the advanced meter outage notifications and voltage alerts
- GMS Phase 1 telecommunications gateway to receive data from both advanced meters and distribution field devices

C. SYSTEMATIC AND LOGICAL IMPLEMENTATION SEQUENCE

The ADMS tool will provide grid operators with core DMS capabilities. In order for the ADMS to function as needed with the desired capabilities, the GIS data that identifies each component of the distribution grids for each island is loaded into the ADMS with a network

model that details how each of the distribution infrastructure components are connected, including switching schemes and phases. The distribution grid has grown over time, with many components dating back to the post–World War II time frame.[9] As a result, paper drawings have been digitized, and there will likely be an effort to validate the distribution model once loaded into the ADMS. The ADMS has some tools to assist with this model validation and will help identify areas that may need a distribution engineering review or field validation to ensure that the infrastructure specifications and connectivity configurations are modeled correctly. This is a common undertaking as utilities work to model the distribution grid in these sophisticated DMS software tools.

The ADMS will also include OMS capability that will receive advanced meter outage alerts as well as outage notifications from other devices such as SCADA and remote fault indicators to coordinate the Companies' outage responses. The Fault Location Isolation and Service Restoration ("FLISR") module of the ADMS helps more accurately identify the location and root cause of an outage. FLISR also recommends switching schemes to minimize the number of customers affected by an outage. Grid operators can then utilize the ADMS to implement the switching scheme with remote intelligent switches. The OMS component of the ADMS then coordinates with field crews to ensure safe and efficient restoration of power by guiding them to the likely source of the outage and tagging the energized and de-energized sections of the system. The OMS also enables outage information updates for customers, including estimated time to restoration, which will continue to be refined as the documented history of outage restoration is accumulated after OMS implementation.

In order to improve field crew efficiency in outage restoration, the OMS component must interface with the SAP Work Orders, which provides instruction to field crews for system restoration based on the distribution operator dispatches, which are guided by insight from the ADMS OMS component. The SAP Work Orders are also used to perform field validation of infrastructure components, as well as closes the loop on updating the asset management system and GIS when new equipment is installed either during outage restoration or during routine equipment upgrades or aging infrastructure replacement. The updated GIS "as-built" model data then populates the ADMS network model which controls the "as-operated" configuration.

D. INTERFACING WITH THE DEMS

The Commission previously approved the implementation of a Demand Response Management System ("DRMS"), which will evolve into a Distributed Energy Resource Management System ("DERMS"), resulting in the Companies' recent implementation of the DEMS[10] in Docket No. 2015-0411, Decision and Order No. 34884. The ADMS will interface

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[9] See Docket No. 2017-0226, *Modernizing Hawai'i's Grid For Our Customers*, filed August 29, 2017, Figures 10-12.

[10] Hawaiian Electric successfully implemented the Siemens Energy IP DEMS and went live with the DEMS on February 24, 2019.

with the DEMS in order to dispatch DR and DER resources. The DEMS will manage the customer- and aggregator-facing aspects of the available customer energy options, while the ADMS will manage the distribution system and dispatch DER as needed to meet grid needs. For example, as part of the Integrated Grid Planning ("IGP")[11] activities, the Companies are conducting a "soft launch" of non-wired alternatives ("NWA") to address capacity constraints on two areas: (1) Hoʻopili and (2) East Kapolei.[12] Once implemented, the ADMS will monitor those circuits to determine when the dispatchable distributed resources in those two areas are needed to stay within the capacity rating of the infrastructure. Capacity ratings specify the physical limitations of the distribution infrastructure denoting the amount of electricity that can flow through the different components of the system. Exceeding these limits for a sustained period of time could lead to safety and/or reliability issues, such as the failure of a conductor or transformer. The ADMS will send a dispatch request to the DEMS when DER and/or DR capacity is needed. The DEMS will relay that command to the participating DER aggregator(s) and participating customers. Following dispatch, the advanced meters will provide interval data through the GMS Phase 1 MDMS to the DEMS to perform the measurement and verification ("M&V") on the customer-owned resources and the aggregated DER resource (or resources) as a whole.

E. SYSTEM INTEGRATION

The system integration effort to enable the interfaces between ADMS, EMS, DEMS, SAP, GIS, telecom gateway, meter head-end, and MDMS and other systems makes up a significant amount of the estimated Project cost. Figure 5 shows a high-level depiction of these system interfaces from the National Institute of Standards and Technology ("NIST") Domain and Logical Model for Grid Information Networks framework.[13] The color-coded legend illustrates how investments being made from different dockets combine together to provide the core cyber-physical grid platform technology envisioned in the GMS.

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[11] See Hawaiian Electric Companies' Integrated Grid Planning (IGP) Distribution Planning & Grid Services Working Groups: https://www.hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning/stakeholder-engagement/working-groups/distribution-planning-and-grid-services-documents

[12] Integrated Grid Planning (IGP) Distribution Planning & Grid Services Working Groups: https://www.hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning/stakeholder-engagement/working-groups/distribution-planning-and-grid-services-documents

[13] See National Institute of Standards and Technology ("NIST") Framework and Roadmap of Smart Grid Interoperability Standards, Section 5.3 Smart Grid Architecture Model: https://www.nist.gov/engineering-laboratory/smart-grid/framework-and-road-map-smart-grid-interoperability

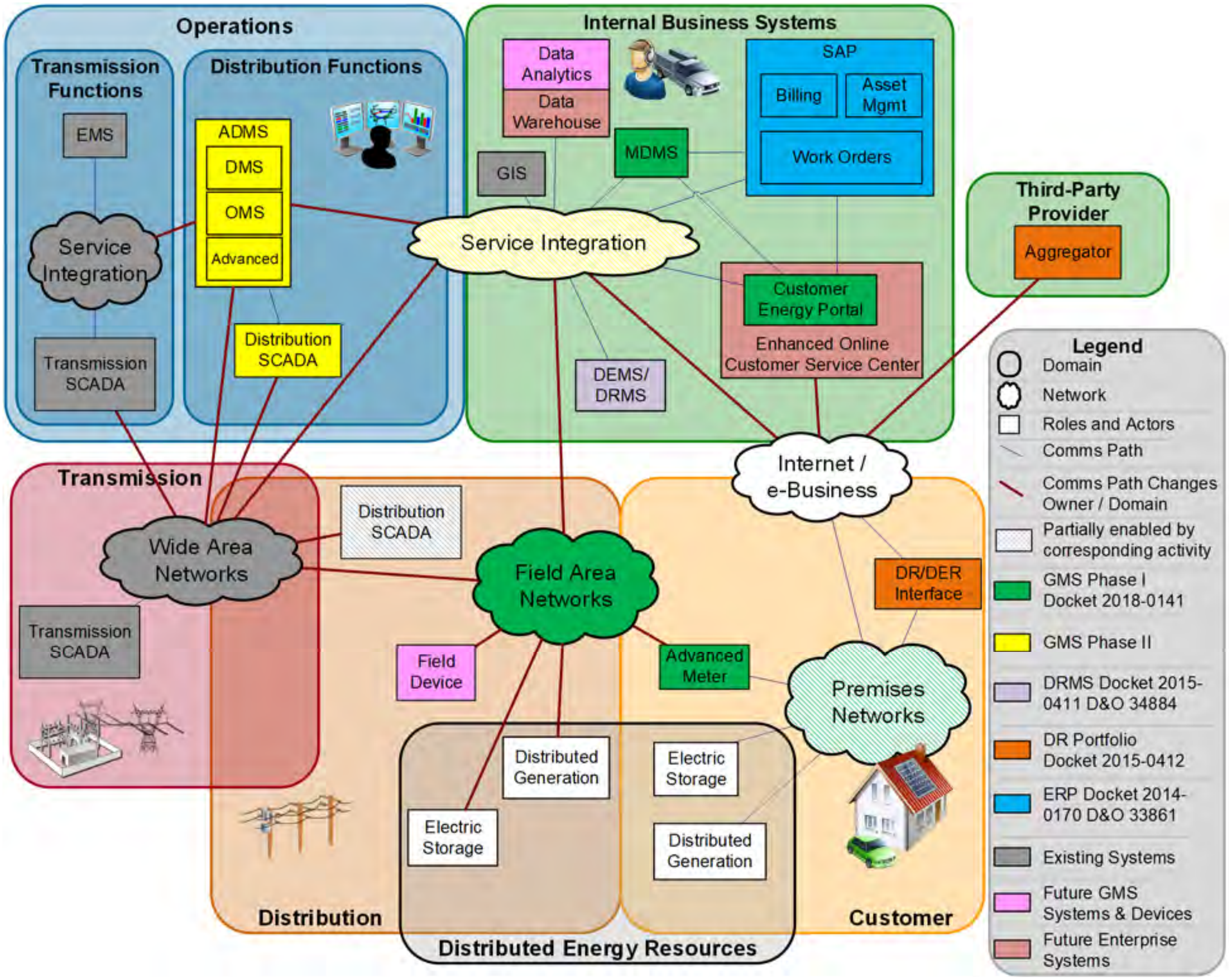

Figure 5

II. <u>CYBERSECURITY AND PRIVACY FOR GRID MODERNIZATION STRATEGY IMPLEMENTATION</u>

The protection of business and customer information is a serious undertaking for the Hawaiian Electric Companies. This is especially true with the advent of transforming into the modern utility of the future that utilizes "smart" technologies leveraging seamless connectivity and information greater than ever before. With this increase in network connectivity and use of information, there is an elevated risk of cyber attacks, as the number of access points to the grid increases. Successful attacks could lead to the loss of customer and/or business data, potentially resulting in privacy issues, financial losses, and/or even damage to the grid infrastructure itself.

The GMS implementation and operation will be subject to requirements of the Companies' cyber security program, which is a comprehensive set of policies, plans, standards, and practices aligned with the National Institute of Standards and Technology ("NIST") Cyber Security Framework ("CSF"). The program is a risk-based approach to managing cyber security

threats and vulnerabilities. Programmatic practices leverage cybersecurity technologies that are designed to protect, monitor, and manage systems and networks such that unauthorized activity is prevented and/or detected and rapidly isolated and remediated. This includes fortifying existing mitigations such as multi-level access controls, anti-malware solutions, and a variety of intrusion detection sensors monitored by a network operations and security center, while providing for additional security zones, more rigorous data management, and expanded security information and event management capabilities. As discussed below, this combination of incremental cybersecurity capabilities and monitoring and management practices will facilitate grid modernization in a safe and secured environment.

A. GMS IMPLICATIONS FOR CYBERSECURITY

GMS technologies will make the enterprise systems more complex, with new applications, network access points and data introduced into the grid. The GMS Project includes installation of advanced metering and telecommunications to support devices as well as additional computing systems such as a MDMS and ADMS that add new functionality to the grid. All of these changes will present potential vulnerabilities, both known and unknown.[14] With the implementation of multiple GMS systems and the more robust and bidirectional data exchanges throughout the enterprise, threats, vulnerabilities and impact will all increase at a substantially higher rate. This means cybersecurity-related risks will also substantially increase.

The systems to be implemented as part of the GMS are not simply new versions of old systems. The Companies will be integrating new types of systems, and these systems will add connectivity and data at the service location endpoints and through the distribution level of the grid. This represents an unprecedented and new capability that converges information technology ("IT") and operational technology ("OT") networks.[15] For instance, advanced meters will now provide usage and operational data from the service location endpoint to both a centralized MDMS for billing purposes as well as grid management systems like the ADMS used to provide for higher concentrations of renewable energy at the distribution level.

These systems will be a hybrid of sorts, combining capabilities and data exchanges to traditional business systems, as well as to traditional control systems. These two-way data exchanges will require enhanced network segmentation and the establishment of additional security zone.

The RF mesh FAN being installed as part of the GMS Project will expand the "attack surface" of the Companies' enterprise data networks. This RF network will include substantially

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[14] The National Association of Regulatory Utility Commissioners ("NARUC") describes the Smart Grid cyber-security challenge in this way: "With the advent of smart grid technologies, which layer software on top of utility operations and computer systems, threats become increasingly likely and relevant." Cybersecurity for State Regulators 2.0, NARUC (2013).

[15] See John P. Roberts and Kristian Streenstrup, The Management Implications of IT/OT Convergence, Gartner Inc. (March 4, 2010).

more access points than the traditional microwave and fiber optic Wide Area Network ("WAN") data links that the Companies have operated for many years. The addition of new GMS solutions into the OT control centers and IT data centers further emphasizes the importance of protecting the overall infrastructure, as previously isolated network segments must now be connected and securely exchange data.

B. GMS CYBERSECURITY SAFEGUARDS

GMS implementation will require the Companies' cybersecurity protective measures and controls to be more comprehensive and standardized to industry best practices. Among the risk mitigations planned for the GMS Project are increased data network segmentation (to isolate components), additional intrusion sensors with related security event logging/analysis, additional data encryption, penetration tests, third-party security risk assessments, and tighter processes to restrict data access. Securely enabling these new grid capabilities and customer enhancements will require additional investment in cybersecurity controls for the data networks.

The Companies have demonstrated a deliberate and proactive approach to protect against cyber-attacks and unwarranted intrusions. Some components of the Itron (formerly known as Silver Spring Networks) Enhanced Security Package were implemented during the Companies' Smart Grid Initial Phase demonstration project ("Initial Phase") on O'ahu, at that time becoming one of the first utilities nationwide to utilize this additional level of security capabilities. The Companies plan to continue to utilize similar enhanced features, along with additional layers of protection as they implement the GMS Project throughout their service territories.

The Companies' existing and planned security and privacy measures, including programmatic alignment to the NIST CSF to manage these safeguards and controls, coupled with the advanced software solutions will result in a robust, comprehensive cybersecurity risk mitigation framework that will guide their GMS implementation. This framework will create a unified approach in which the Companies can better prepare, prevent and recover from potential threats and ensure that customer and business information is kept protected.

1. Cybersecurity Risk Mitigation Framework

The NIST *CSF*[16] describes five stages for its core risk mitigation functions: Identify, Protect, Detect, Respond, and Recover – each of which is discussed in turn below. Alignment with frameworks such as this helps illustrate how the Companies are addressing mitigations in a comprehensive manner. Collectively, these tools and processes represent a "defense-in-depth"[17] strategy. In addition to incorporating protection mechanisms, the Companies need to expect attacks and include attack detection tools and procedures to react to and recover from these

[16] Available at http://www.nist.gov/cyberframework/.
[17] Also known as *Castle Approach*, an information concept in which multiple layers of security controls (defense) are placed throughout an information technology system.

attacks. The Companies also need to maintain a balance between the protection capability, and cost, performance and operational considerations.

Identify

The *Identify* core function is to develop the organizational understanding to manage cybersecurity risk to systems, assets, data and capabilities. Standard risk identification strategies for complex computing environments include both penetration testing and security risk assessments, typically conducted by independent third parties. Penetration testing is a proactive measure to discover and exploit the security of an IT or OT infrastructure. A security risk assessment is a comprehensive study to discover and describe threats, vulnerabilities and risks, and to recommend system-specific risk mitigations. Several penetration tests and vulnerability assessments will be conducted by different third parties during the GMS Project as part of the system development life cycle release process.

Protect

The *Protect* core function is to develop and implement the appropriate safeguards to ensure delivery of critical information and infrastructure. Within this function, there is the need for network segmentation, management for encryption and cryptographic keys utilized by advanced meters and other remote devices, and endpoint protection for the required servers and workstations that will harvest the information transmitted over the GMS' telecommunication network. Collectively, these will serve as additional layers of reinforcement against unauthorized intrusions during the GMS Project.

Network Segmentation

With the solutions added for GMS Project, data will be generated and consumed in a far more integrated and enterprise-wide manner than before. Additional layers of security are required to provide greater defense-in-depth. In determining how to better protect the GMS systems, the Companies considered the underlying data system infrastructure – not just OT data systems or IT data systems, but all data systems regardless of function or physical location within the enterprise.

The introduction of advanced meters and field devices into the Companies' information and control systems environment creates many new data sets. It also creates a requirement for data exchanges across traditionally isolated data network environments. Advanced meter and field device integration will require enhanced data network segmentation in order to better protect the network environments from compromise.

Encryption and Cryptographic Key Management Systems

Hawai‘i law provides guidance for companies in the protection of customer data.[18] The Companies have implemented an encryption strategy designed to enhance protection of sensitive personally identifiable information at rest. This system has already been implemented and will be expanded to accommodate the new GMS systems.

Cryptographic key management systems (“CKMS”) are used to generate, allocate, verify and revoke credentials used to encrypt data and authenticate data sources on a network. With the integration of grid modernization systems, particularly advanced meters, the Companies will transition from managing a few thousand cryptographic keys to managing potentially millions of cryptographic keys. Each of the advanced meters will have multiple cryptographic key pairs; each pair will be used to protect different meter data sets and commands. Additional cryptographic certificates will be used to establish virtual private networks for purposes of protecting data in transit. Doing so will require investment in CKMS and staffing to manage these certificates across the Companies.

Endpoint Protection (Servers and Workstations)

The Companies utilize a variety of standard endpoint protection systems such as signature- and behavioral-based malware detection systems. These capabilities will be extended to the GMS systems that are deployed during the GMS Project.

Detect

The *Detect* core function is to develop and implement the appropriate activities to identify the occurrence of a cyber-attack. These activities include a network intrusion detection system, a network and website scanning service, and a security incident event management system leveraged by Hawaiian Electric’s Network Operations and Security Center (NOC) to constantly monitor and detect any threats or attacks that may arise. As described in the Application, future phases of the GMS implementation include a network operations center to monitor and administer the telecommunications system. The Companies will explore the current capabilities of the NOC to assess if an expansion of the NOC would support the GMS implementation or if a separate NOC is required.

The Companies utilize a variety of commercially available devices to detect anomalous activity on their data networks that could indicate a network intrusion. Network intrusion detection system devices are continuously monitored by the NOC personnel. The Companies also utilize a variety of commercially available systems to scan servers to detect vulnerabilities in applications and operating systems. This includes software tools used by employees on site, as well as third-party service providers which scan the Companies’ public-facing websites.

[18] See Hawai‘i Revised Statutes, Chapter 487N (Security Breach of Personal Information law).

Security control assessments are integrated in a continuous monitoring practice to ensure that safeguards and countermeasures remain effective in the Companies' ever-evolving operating and technological environments.

In addition, with the enhanced data network segmentation described above, there will be more security zones from which to collect and correlate security events. This includes the additional firewalls to protect the perimeter of each zone, as well as the applications and other network appliances within the zones. Each of these devices creates an event log, and the log files are collected, aggregated, correlated and analyzed by the NOC to detect any potential threats or attempted threats that may arise.

Respond

The *Respond* core function is to develop and implement the appropriate activities in response to a known or suspected cyber-attack. Incident response programs specify actions to be taken when the Companies suspect or detect unauthorized access to customer information systems, including appropriate reports to government agencies. New capabilities to utilize forensic analysis tools and services are also being developed in order to improve the effectiveness of the incident response process. The Companies will extend these capabilities to their GMS systems.

Recover

The *Recover* core function is to develop and implement the appropriate activities to maintain plans for resilience and to restore any capabilities or services that may be impaired due to a cyber-attack. Recovery processes and policies are important to the restoration of capabilities or critical infrastructure services impaired during a cyber-attack. This includes coordination of communications necessary to support timely recovery and reduce the impact of an event. The Companies will continue to improve their infrastructure and systems architecture to better support both continuous operation and graceful degradation[19] in preparation of potential attacks, as well as resistance, resilience, and recovery after an attack. These capabilities will also be extended to GMS systems.

Some of the risk mitigation activities described above, such as anti-malware solutions and network scanning tools, are extensions of existing capabilities, which the Companies have had in place for several years. However, for some of the more substantial risk mitigation activities, such as the additional network segmentation, security information event management, encryption and cryptographic key management capabilities, additional investment will be required to better protect the more robust data and more complex grid infrastructure required by the GMS.

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[19] Graceful degradation is the tactical response of a computer or network to maintain limited functionality if a portion of the system has been rendered inoperative in order to prevent catastrophic failure.

III. CONCLUSION

The Companies understand and are vigilant about mitigating the potential risks posed by the implementation of GMS technologies. Customer information and privacy is one of the Companies' highest priorities. That is why in addition to their existing cybersecurity systems, the Companies have matured their cyber security program by leveraging NIST CSF, and extensively prepared their operational configurations to accommodate the need for additional infrastructure required to protect against any unauthorized intrusions or cyber-based attacks on a modernized grid. It is through a robust privacy framework, coupled with informed customers, that customer data will be protected. In connection with the GMS Project, there will be ongoing assessments, testing, and evaluation of the services and processes in place to ensure that changes in cybersecurity and privacy protection measures are kept current, and that all customer, legal and regulatory requirements are met. As new threats or vulnerabilities emerge, the Companies will implement commensurate risk-based measures to accommodate the additional demands of their data management and privacy procedures, to ensure customer information is kept protected.

PROJECT COST ESTIMATE

Project Title: GMS Phase 2 ADMS
Budget Item: **See Below**

	CONSOLIDATED		
	Pre-Implementation	**Implementation**	**Annual On-Going**
LABOR (INCREMENTAL)		$ [redacted]	$ [redacted]
MATERIALS			
OUTSIDE SERVICES	$ [redacted]	$ [redacted]	$ [redacted]
OTHER (HARDWARE)		$ [redacted]	
OVERHEAD		$ [redacted]	$ [redacted]
AFUDC		$ [redacted]	
TOTAL COST OF PROJECT	$ [redacted]	$ [redacted]	$ 1,808,233
ESTIMATED CONTRIBUTIONS	$ -	$ -	$ -
NET PROJECT COST	$ [redacted]	$ [redacted]	$ 1,808,233

PROJECT COST ESTIMATE

Project Title GMS Phase 2 ADMS
Budget Item **See Below**

	Pre-Implementation HECO	Implementation HECO	Annual On-Going HECO	Pre-Implementation HELCO	Implementation HELCO	Annual On-Going HELCO	Pre-Implementation MECO	Implementation MECO	Annual On-Going MECO
LABOR (INCREMENTAL)		$ [redacted]	$ [redacted]		$ [redacted]	$ [redacted]		$ [redacted]	$ [redacted]
MATERIALS									
OUTSIDE SERVICES	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]
OTHER (HARDWARE)		$ [redacted]			$ [redacted]			$ [redacted]	$ [redacted]
OVERHEAD		$ [redacted]	$ [redacted]		$ [redacted]	$ [redacted]		[redacted]	
AFUDC		$ [redacted]			$ [redacted]			$ [redacted]	
TOTAL COST OF PROJECT	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]
ESTIMATED CONTRIBUTIONS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NET PROJECT COST	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]

Project Title GMS Phase 2 - ADMS
Budget Item Labor (Incremental)

	Group	Hours							Dollars						
		Implementaion	Annual On-Going	Implementaion	Annual On-Going	Implementaion	Annual On-Going		Implementaion	Annual On-Going	Implementaion	Annual On-Going	Implementaion	Annual On-Going	
		HECO	HECO	HELCO	HELCO	MECO	MECO		HECO	HECO	HELCO	HELCO	MECO	MECO	
SYSTEM OPERATIONS															
Operating Engineering	(RE)	14,496	3,624					18,120	[redacted]	[redacted]					[redacted]
Operating Dispatch	(RD)	7,024	1,756					8,780							
								-							
Systems	(RS)			13440	4480			17,920			[redacted]	[redacted]			[redacted]
								-							
Admin - System Operations	(OA)					5472	1824	7,296					[redacted]	[redacted]	[redacted]
Dispatch - System Operations	(OD)					7968	2656	10,624							
								-							
Total		21,520	5,380	13,440	4,480	13,440	4,480	62,740	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Exhibit H

GMS Phase 2 ADMS Application

Bill Impact

REVENUE REQUIREMENTS AND BILL IMPACTS

The Hawaiian Electric Companies[1] performed a high level, economic analysis to forecast revenue requirements and bill impacts for the Advanced Distribution Management System ("ADMS") component ("Project"), of the second phase ("Phase 2") of the Grid Modernization Strategy implementation. This high level forecast uses broad or simplified assumptions for the purpose of estimating revenue requirements over the life of the investment and a typical monthly residential bill impact. Actual results may differ based on the application of specific rules and on the actual costs incurred.

The forecast analysis assumed a typical residential customer uses 500kWh per month. Bill impacts reflect a 17 year period for Phase 2. The forecasted bill impact excludes Phase 2 Field Devices and other future replacement costs. Beyond the ADMS component of Phase 2 (2024), the Companies will need to continue to invest in and modernize the grid. At this time the scope and scale of this future effort are not known. Technology is evolving at a rapid pace. As a result, the Companies will need to assess the needs of the customers and the grid in order to pair the appropriate technology that is available. Replacements will be included in future filings or rate cases.

Table 1 – Consolidated Revenue Requirement ($ in millions)

Year	Hawaiian Electric	Hawai'I Electric Light	Maui Electric	Consolidated
2020	0.29	0.25	0.30	0.84
2021	2.07	0.04	0.04	2.15
2022	2.66	0.93	0.96	4.55
2023	3.82	1.84	1.83	7.49
2024	4.60	2.06	2.05	8.71
2025	4.35	2.19	2.28	8.82
2026	4.02	2.06	2.16	8.24
2027	3.88	1.87	1.96	7.71
2028	3.75	1.81	1.92	7.48
2029	3.62	1.76	1.87	7.25
2030	3.49	1.71	1.82	7.02
2031	3.36	1.66	1.78	6.80
2032	3.24	1.61	1.72	6.57
2033	3.11	1.56	1.67	6.34
2034	2.44	1.45	1.58	5.47
2035	1.57	1.06	1.16	3.79
2036	1.29	0.82	0.94	3.05
Total	51.56	24.68	26.04	102.28
NPV	29.44	13.37	14.31	57.12

Revenue Requirement rounded to the nearest $10,000.

[1] Hawaiian Electric, Hawai'i Electric Light and Maui Electric are collectively referred to as the "Hawaiian Electric Companies" or the "Companies."

Confidential Information Deleted
Pursuant to Protective Order No. ______________

Table 2 – Hawaiian Electric Revenue Requirement ($ in millions) and Bill Impact

Year		ADMS Revenue Requirement[1]	Job Analysis O&M Revenue Requirement[1]	O&M Revenue Requirement[1]	Post Go-Live O&M Revenue Requirement[1]	Total Revenue Requirement[1]	Benefits[2]	Total Revenue Requirement Net of Benefits	Estimated MWh Sales[3]	Rate Impact cents per kWh	Bill Impact 500 kWh[4]
								A	B	C=(A*100)/(B*1000)	D=C*500/100
2020	1	[redacted]	[redacted]	[redacted]	[redacted]	0.29	-	0.29	6,546,500	0.0044	$ 0.02
2021	2	[redacted]	[redacted]	[redacted]	[redacted]	2.07	[redacted]	2.07	6,583,700	0.0314	$ 0.16
2022	3	[redacted]	[redacted]	[redacted]	[redacted]	2.85	[redacted]	2.76	6,627,800	0.0416	$ 0.21
2023	4	[redacted]	[redacted]	[redacted]	[redacted]	4.01	[redacted]	3.82	6,642,200	0.0575	$ 0.29
2024	5	[redacted]	[redacted]	[redacted]	[redacted]	4.79	[redacted]	4.60	6,623,900	0.0694	$ 0.35
2025	6	[redacted]	[redacted]	[redacted]	[redacted]	4.54	[redacted]	4.35	6,571,300	0.0662	$ 0.33
2026	7	[redacted]	[redacted]	[redacted]	[redacted]	4.02	-	4.02	6,498,300	0.0619	$ 0.31
2027	8	[redacted]	[redacted]	[redacted]	[redacted]	3.88	-	3.88	6,398,200	0.0606	$ 0.30
2028	9	[redacted]	[redacted]	[redacted]	[redacted]	3.75	-	3.75	6,325,000	0.0593	$ 0.30
2029	10	[redacted]	[redacted]	[redacted]	[redacted]	3.62	-	3.62	6,209,100	0.0583	$ 0.29
2030	11	[redacted]	[redacted]	[redacted]	[redacted]	3.49	-	3.49	6,068,800	0.0575	$ 0.29
2031	12	[redacted]	[redacted]	[redacted]	[redacted]	3.36	-	3.36	5,997,500	0.0560	$ 0.28
2032	13	[redacted]	[redacted]	[redacted]	[redacted]	3.24	-	3.24	5,948,400	0.0545	$ 0.27
2033	14	[redacted]	[redacted]	[redacted]	[redacted]	3.11	-	3.11	5,927,000	0.0525	$ 0.26
2034	15	[redacted]	[redacted]	[redacted]	[redacted]	2.44	-	2.44	5,886,100	0.0415	$ 0.21
2035	16	[redacted]	[redacted]	[redacted]	[redacted]	1.57	-	1.57	5,867,400	0.0268	$ 0.13
2036	17	[redacted]	[redacted]	[redacted]	[redacted]	1.29	-	1.29	5,869,500	0.0220	$ 0.11
Total		[redacted]	[redacted]	[redacted]	[redacted]	52.32	(0.67)	51.66		Average	$ 0.24
NPV @	7.03%	20.35	0.27	3.56	5.82	30.00	(0.48)	29.52			

Notes:
1. Revenue Requirement rounded to the nearest $10,000.
2. An offset of [redacted] due to the retirement of the existing OMS at Hawaiian Electric is recorded annually until the next rate case. 2022 consists of a half year savings due to the in-service date of June 2022 for Release 1 at Hawaiian Electric.
2. Estimated Hawaiian Electric Sales (in whole $).
3. Hawaiian Electric typical residential energy consumption, per month.

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Table 3 – Maui Electric Revenue Requirement ($ in millions) and Bill Impact

Year		ADMS Revenue Requirement[1]	Job Analysis O&M Revenue Requirement[1]	O&M Revenue Requirement[1]	Post Go-Live O&M Revenue Requirement[1]	Total Revenue Requirement[1]	Estimated MWh Sales[2]	Rate Impact cents per kWh	Bill Impact 500 kWh[3]
						E	F	G=(E*100)/(F*1000)	H=G*500/100
2020	1	[redacted]				0.30	1,042,081	0.0288	$ 0.14
2021	2	[redacted]				0.04	1,025,924	0.0039	$ 0.02
2022	3	[redacted]				0.96	1,022,472	0.0939	$ 0.47
2023	4	[redacted]				1.83	1,019,220	0.1795	$ 0.90
2024	5	[redacted]				2.05	1,020,047	0.2010	$ 1.00
2025	6	[redacted]				2.28	1,016,381	0.2243	$ 1.12
2026	7	[redacted]				2.16	1,013,857	0.2130	$ 1.07
2027	8	[redacted]				1.96	1,012,476	0.1936	$ 0.97
2028	9	[redacted]				1.92	1,011,426	0.1898	$ 0.95
2029	10	[redacted]				1.87	999,876	0.1870	$ 0.94
2030	11	[redacted]				1.82	987,572	0.1843	$ 0.92
2031	12	[redacted]				1.78	984,638	0.1808	$ 0.90
2032	13	[redacted]				1.72	997,411	0.1724	$ 0.86
2033	14	[redacted]				1.67	1,011,324	0.1651	$ 0.83
2034	15	[redacted]				1.58	1,028,138	0.1537	$ 0.77
2035	16	[redacted]				1.16	1,047,686	0.1107	$ 0.55
2036	17	[redacted]				0.94	1,070,060	0.0878	$ 0.44
Total		[redacted]				26.04		Average	$ 0.76
NPV @	6.94%	8.60	0.28	1.33	4.10	14.31			

Notes:
1. Revenue Requirement rounded to the nearest $10,000.
2. Estimated Maui Electric Sales (in whole $).
3. Maui Electric typical residential energy consumption, per month.

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Table 4 – Hawai'i Electric Light Revenue Requirement ($ in millions) and Bill Impact

Year		ADMS Revenue Requirement[1]	Job Analysis O&M Revenue Requirement[1]	O&M Revenue Requirement[1]	Post Go-Live O&M Revenue Requirement[1]	Total Revenue Requirement[1]	Estimated MWh Sales[2]	Rate Impact cents per kWh		Bill Impact 500 kWh[3]
						I	J	K=(I*100)/(J*1000)		L=K*500/100
2020	1	[redacted]				0.25	1,062,299	0.0235	$	0.12
2021	2					0.04	1,056,412	0.0038	$	0.02
2022	3					0.93	1,051,255	0.0885	$	0.44
2023	4					1.84	1,043,117	0.1764	$	0.88
2024	5					2.06	1,036,029	0.1988	$	0.99
2025	6					2.19	1,025,234	0.2136	$	1.07
2026	7					2.06	1,014,638	0.2030	$	1.02
2027	8					1.87	1,002,912	0.1865	$	0.93
2028	9					1.81	1,005,886	0.1799	$	0.90
2029	10					1.76	993,868	0.1771	$	0.89
2030	11					1.71	988,846	0.1729	$	0.86
2031	12					1.66	980,169	0.1694	$	0.85
2032	13					1.61	986,449	0.1632	$	0.82
2033	14					1.56	989,250	0.1577	$	0.79
2034	15					1.45	997,178	0.1454	$	0.73
2035	16					1.06	1,008,771	0.1051	$	0.53
2036	17					0.82	1,023,894	0.0801	$	0.40
Total						24.68		Average	$	0.72
NPV @	7.20%	8.40	0.23	1.29	3.45	13.37				

Notes:
1. Revenue Requirement rounded to the nearest $10,000.
2. Estimated Hawai'i Electric Light Sales (in whole $).
3. Hawai'i Electric Light typical residential energy consumption, per month.

KEY ASSUMPTIONS USED IN FINANCIAL ANALYSIS

The Companies utilized various assumptions in the high level, economic analysis to forecast revenue requirements and bill impacts. This high level forecast uses broad or simplified assumptions for the purpose of estimating revenue requirements over the life of the investment and a typical monthly residential bill impact. Actual results may differ based on the application of specific rules and on the actual costs incurred. The key assumptions are highlight in the following sections.

I. COST OF CAPITAL ASSUMPTIONS

Cost of capital assumptions are based on the current approved rate case for each Company. Please refer to figures 1 through 3 below for current assumptions used in the forecast.

Figure 1 – Hawaiian Electric

HECO TY2017 Rate Case Dkt 2016-0328 Final D&O 35545

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	1.18%	1.75%	0.02%	0.02%	0.023%	0.02%
Long Term Debt (Taxable Debt)	39.59%	5.03%	1.99%	1.48%	2.186%	1.99%
Hybrids	1.22%	7.19%	0.09%	0.07%	0.096%	0.09%
Preferred Stock	0.90%	5.37%	0.05%	0.05%	0.072%	0.07%
Common Stock	57.10%	9.50%	5.42%	5.42%	8.018%	7.31%
	100.00%		7.57%	7.032%	10.395%	9.471%

Figure 2 – Maui Electric

MECO TY2018 Rate Case Dkt 2017-0150 Final D&O No. 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%	1.928%	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%	9.341%

Figure 3 – Hawai'i Electric Light

HELCO TY2016 Rate Case Dkt 2015-0170 PUC Final D&O 35559

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	0.00%	1.50%	0.00%	0.00%	0.000%	0.00%
Long Term Debt (Taxable Debt)	40.13%	5.40%	2.17%	1.61%	2.378%	2.17%
Hybrids	1.86%	7.21%	0.13%	0.10%	0.147%	0.13%
Preferred Stock	1.31%	8.18%	0.11%	0.11%	0.159%	0.14%
Common Stock	56.69%	9.50%	5.39%	5.39%	7.961%	7.25%
	100.00%		7.79%	7.202%	10.646%	9.700%

II. TAX ASSUMPTIONS

Tax and tax credit assumptions are based on current Federal and State laws. Please refer to figure 4 below for current assumptions used in the forecast.

Figure 4 – Consolidated

		Effective
Federal Income Tax Rate	21.00%	19.74%
State Income Tax Rate	6.40%	6.02%
		25.75%
State Investment Tax Credit (ITC)		4.00%
Accelerated State ITC Amortization Period		10
Public Service Company Tax		5.885%
PUC Fee		0.500%
Franchise Tax		2.500%
Composite Revenue Tax Rate		8.885%

For forecasting purposes, state investment tax credit was applied to the total capital investment. In reality, certain costs may not be eligible for state investment tax credits. In addition, the amortization period for the state investment tax credit is assumed to be 10 years for all Companies, which is consistent with Hawaiian Electric's 2017 test year rate case and Maui Electric's 2018 test year rate case. Hawai'i Electric Light's 2019 test year rate case parties' stipulated partial settlement letter with the Consumer Advocate includes a 40 year amortization period.

III. DEPRECIATION AND AMORTIZATION ASSUMPTIONS

Depreciation and amortization assumptions are based on the expected useful life of the investment. Depreciation is forecasted to begin the year after the asset is placed into service. In reality, depreciation will be based on current Commission-approved depreciation rates. Please refer to figure 5 below for current assumptions used in the forecast.

Figure 5 – Consolidated

	Hardware	Deferred Software
Expected Useful Life	5	12
MACRS Tax Life ("Tax Life")	20	20
Tax Class Life ("Class Life")	-	-

IV. INVESTMENT ASSUMPTIONS

Investment assumptions are based on the forecasts of costs based on the scope of Phase 1. Please refer to figures 6 through 8 below for current assumptions used in the forecast.

Figure 6 – Hawaiian Electric

Project	2020	2021	2022	2023	2024	2025	Useful Life
Job Analysis O&M	[redacted]	-	-	-	-	-	
Hardware	-	[redacted]	-	-	-	-	5
Deferred Software	-	-	[redacted]	[redacted]	[redacted]	-	12
O&M	-	[redacted]	[redacted]	[redacted]	[redacted]	-	
Post Go-Live O&M	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
TOTAL	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	

Figure 7 – Maui Electric

Project	2020	2021	2022	2023	2024	2025	Useful Life
Job Analysis O&M	[redacted]	-	-	-	-	-	
Hardware	-	-	[redacted]	-	-	-	5
Deferred Software	-	-	[redacted]	[redacted]	[redacted]	-	12
O&M	-	[redacted]	[redacted]	[redacted]	[redacted]	-	
Post Go-Live O&M	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
TOTAL	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	

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Figure 8 – Hawai‘i Electric Light

Project	2020	2021	2022	2023	2024	2025	Useful Life
Job Analysis O&M	[redacted]	-	-	-	-	-	
Hardware	-	-	[redacted]	-	-	-	5
Deferred Software	-	-	[redacted]	[redacted]	[redacted]	-	12
O&M	-	[redacted]	[redacted]	[redacted]	[redacted]	-	
Post Go-Live O&M	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
TOTAL	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	

Exhibit I

GMS Phase 2 ADMS Application

Hawaiian Electric Companies' Decoupling Calculation Workbook

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HAWAIIAN ELECTRIC COMPANY, INC.
DECOUPLING CALCULATION WORKBOOK
ILLUSTRATIVE - DETERMINATION OF TARGET REVENUES

Line No.	Description	Reference		Docket No. 2016-0328 Amounts	Docket No. 2016-0328 Amounts	Docket No. 2016-0328 Amounts	Note (7) ILLUSTRATIVE Effective 1/1/2021 (GMS)
	(a)	(b)		(c)	(d)	(e)	(f)
1	Last Rate Case Annual Electric Revenue at Approved Rate Levels	Note (2), (3), (4)	$000s	$ 1,529,709	$ 1,529,709	$ 1,529,709	$ -
1a	Less: Holdback of Interim Revenues	Note (3)	$000s	$ -	$ -	$ -	$ -
1b	Less: Customer Benefit Adjustment	Note (3)	$000s	$ -	$ -	$ -	$ -
2	Less: Fuel Expense	Note (2), (3), (4)	$000s	$ (327,609)	$ (327,609)	$ (327,609)	$ -
3	Purchased Power Expense	Note (2), (3), (4)	$000s	$ (466,211)	$ (466,211)	$ (466,211)	$ -
4	Revenue Taxes on Line 1 to 1b (8.885% statutory rates)		$000s	$ (135,915)	$ (135,915)	$ (135,915)	$ -
5	Last Rate Order Target Annual Revenues	Sum Lines 1...4	$000s	$ 599,974	$ 599,974	$ 599,974	$ -
6	Authorized RAM Revenues	Note (5)	$000s	$ 13,828	$ -	$ -	$ -
7	Less: Revenue Taxes on Line 9 at 8.885%		$000s	$ (1,229)	$ -	$ -	$ -
8	Net RAM Adjustment - Test Year +1	Lines 6 + 7	$000s	$ 12,599	$ -	$ -	$ -
9	Authorized RAM Revenues	Sch A, Line 4	$000s	$ -	$ 20,351	$ 20,351	$ -
10	Less: Revenue Taxes on Line 12 at 8.885%		$000s	$ -	$ (1,808)	$ (1,808)	$ -
11	Net RAM Adjustment - Test Year +2	Lines 9 + 10	$000s	$ -	$ 18,543	$ 18,543	$ -
12	Authorized MPIR Revenues - SCHOFIELD	Schedule L	$000s	$ 19,811	$ 19,811	$ 19,811	$ -
13	Less: Revenue Taxes on Line 15 at 8.885%		$000s	$ (1,760)	$ (1,760)	$ (1,760)	$ -
14	Net MPIR Adjustment	Lines 12 + 13	$000s	$ 18,051	$ 18,051	$ 18,051	$ -
15	Authorized MPIR Revenues - GRID MOD	Schedule L	$000s	$ -	$ -	$ -	$ [redacted]
16	Less: Revenue Taxes on Line 15 at 8.885%		$000s	$ -	$ -	$ -	$ [redacted]
17	Net MPIR Adjustment	Lines 15 + 16	$000s	$ -	$ -	$ -	$ [redacted]
18	Less: EARNINGS SHARING REVENUE CREDITS		$000s	$ -	$ -	$ -	$ -
19	Less: Revenue Taxes on Line 18 at 8.885%		$000s	$ -	$ -	$ -	$ -
20	Net Earnings Sharing Revenue Credits	Lines 18 + 19	$000s	$ -	$ -	$ -	$ -
21	Less: PERFORMANCE INCENTIVE MECHANISM	Sch A, Line 6	$000s	$ -	$ (1,269)	$ (1,269)	$ -
22	Less: Revenue Taxes on Line 24 at 8.885%		$000s	$ -	$ 113	$ 113	$ -
23	Net Performance Incentive Mechanism	Lines 21 + 2	$000s	$ -	$ (1,157)	$ (1,157)	$ -
24	Less: 2017 TEST YEAR FINAL D&O REFUND	Sch A, Line 8	$000s	$ -	$ (48)	$ (48)	$ -
25	Less: Revenue Taxes on Line 27 at 8.885%		$000s	$ -	$ 4	$ 4	$ -
26	Net 2017 Test Year Final D&O Refund	Lines 24 + 25	$000s	$ -	$ (44)	$ (44)	$ -
27	Add: OBF PROGRAM IMPLEMENTATION COSTS	Sch A, Line 1a * 1.0975	$000s	$ -	$ 844	$ 844	$ -
28	Less: Revenue Taxes on Line 21 at 8.885%		$000s	$ -	$ (75)	$ (75)	$ -
29	Net OBF Program Implementation Costs	Lines 27 + 28	$000s	$ -	$ 769	$ 769	$ -
30	PUC-ORDERED MAJOR OR BASELINE CAPITAL CREDITS:		$000s	$ -	$ -	$ -	$ -
31	Total Annual Target Revenues						
32	June 1, 2018 Annualized Revenues w/RAM Increase & MPIR accrued 1/1/19	Col (c)	$000s	$ 630,624			
33	June 1, 2019 Annualized Revenues w/RAM Increase & MPIR accrued 1/1/19	Col (d), (e)	$000s		$ 636,136	$ 636,136	
34	June 1, 2020 Annualized Revenues w/RAM Increase & MPIR accrued 1/1/21	Col (f)	$000s				$ [redacted]
				Note (6)	Note (6)	Note (6)	Note (7)
35	Distribution of Target Revenues by Month:	Note (1)		**2019**	**2019**	**2020**	**2021**
36	January	8.19%		$51,648,125		$52,099,546	[redacted]
37	February	7.59%		$47,864,379		$48,282,729	
38	March	8.10%		$51,080,563		$51,527,023	
39	April	7.98%		$50,323,814		$50,763,660	
40	May	8.40%		$52,972,435		$53,435,431	
41	June	8.07%			$51,336,182		
42	July	8.70%			$55,343,840		
43	August	8.94%			$56,870,566		
44	September	8.65%			$55,025,772		
45	October	8.84%			$56,234,430		
46	November	8.26%			$52,544,841		
47	December	8.28%			$52,672,068		
48	Total Distributed Target Revenues	100.00%		$253,889,316	$380,027,699	$256,108,389	

Footnotes:

1 RBA Tariff Effective February 16, 2018 to reflect 2017 test year.
2 Test Year 2017 Interim Increase provided for in Interim Decision and Order 35100, issued December 15, 2017 in Docket No. 2016-0328:
3 Test Year 2017 2nd Interim Increase provided for in Order No. 35335, issued March 9, 2018 in Docket No. 2016-0328:
4 Reduction for Tax Act Implementation Lag (March 2018 Settlement Tariff Sheets, Attachment 3, filed March 16, 2018, in accordance with Order No. 35335):
5 Transmittal 18-01 filed May 29, 2018, establishing 2018 target revenue effective June 1, 2018.
6 MPIR Revenue accrual starting January 1, 2019 filed in Transmittal 19-01, filed February 7, 2019.
7 For illustration purposes only - MPIR Revenue accrual starting January 1, 2021 filed in Transmittal xx-xx, filed Month Day, Year.

HAWAIIAN ELECTRIC COMPANY, INC.
DECOUPLING CALCULATION WORKBOOK
ILLUSTRATIVE MAJOR PROJECT INTERIM RECOVERY

Line No.	Description	Reference	Amount $000
	(a)	(b)	(c)
1	Grid Modernization Strategy (GMS) - Phase 2	Schedule L1	$
2	Docket No. xxxx-xxxx		
3	Revenue Tax Factor (1/(1-8.885%))		1.0975
4	**Major Project Interim Recovery Total**		$
			To Sch B1, line 15

Note: Per Notice Transmittal to Update Target Revenue for Grid Modernization Strategy (GMS) through the Major Project Interim Recovery Adjustment Recovery Mechanism, filed Month Day, Year, Transmittal No. xx-xx effective January 1, 2021. See Schedule L1.

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To the extent that recovery via the test year varies from actual costs incurred, a MPIR true-up adjustment will be made no later than the next annual MPIR true-up filing.

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HAWAIIAN ELECTRIC COMPANY, INC.
DECOUPLING CALCULATION WORKBOOK
REVENUE REQUIREMENT AND DETERMINATION OF MAJOR PROJECT INTERIM RECOVERY
ILLUSTRATIVE MPIR PROJECT - Grid Modernization Strategy (GMS) - Phase 2
$ in thousands

Line No.	Description	Reference	Recorded at 12/31/2020	2021 Activity	Ending Balance as of 12/31/21	Average Balance	MPIR
	(a)	(b)	(c)	(d)	(e)	(f)=((c)+(e))/2	(g)
	Return on Investment - Grid Modernization Strategy (GMS)						
1	Plant in Service (not to exceed PUC approved amount)	As applicable	-	-	-	-	
2	Accum Depreciation	As applicable	-	-	-	-	
3	Net Cost of Plant in Service		-	-	-	-	
4	ADIT	As applicable	-	-	-	-	
5	State ITC & RETITC	As applicable	-	-	-	-	
6	Total Deductions		-	-	-	-	
7	Total Rate Base		$ -	$ -	$ -	-	
8	Average Rate Base					$ -	
9	Rate of Return (grossed-up for income taxes, before revenue taxes)					9.47%	
10	Annualized Return on Investment (before revenue taxes)						$ -
11	Depreciation Expense (Note 1)	As applicable				-	
12	Operating & Maintenance Expense	Note 2				[redacted]	
12a	Prior year reconciliation of O&M to actuals	Note 2				-	
13	Amortization of State ITC & RETITC	see line 5				-	
14	Lease Rent Expense	Not Applicable				-	
15	Other Expense	Not Applicable				-	
16	Total Expenses						$ [redacted]
17	Total Major Project Interim Recovery						$ [redacted]
18	Revenue Tax Factor (1/(1-8.885%))						1.0975
19	Annualized Revenue for Major Project Interim Recovery						$ [redacted]
							To Sch L

Reconciliation to Schedule B1 (Info Only)

	2021
Annualized Revenue for MPIR	$ [redacted]
Rev Tax Adj	$ [redacted]
Prorated MPIR for Year 1 excl Rev Tax	$ [redacted]
Incremental	$ [redacted]

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: O&M expense represents actual pre-implementation O&M expenses incurred in 2020 for outside services to conduct Job Task Analysis and Job Role Impact Analysis to identify risk and change factors and gaps so that the companies can then develop the necessary competence training and curriculum for using the ADMS. Job Positions may also be redefined. See Exhibit D - Interim Recovery of the Application.

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MAUI ELECTRIC COMPANY, LTD
DECOUPLING CALCULATION WORKBOOK
ILLUSTRATIVE - DETERMINATION OF TARGET REVENUES

Line No.	Description	Reference		Docket No. 2017-0150 Amounts	Docket No. 2017-0150 Amounts	Docket No. 2017-0150 Amounts	Note 3 ILLUSTRATIVE Effective 1/1/2021 (GMS)
	(a)	(b)		(c)	(d)	(e)	(f)
1	Last Rate Case Annual Electric Revenue at Approved Rate Levels	Note 1	$000s	$ 336,045	$ 335,763	$ 335,763	$ -
2	Less: Fuel Expense	Note 1	$000s	$ (103,385)	$ (103,385)	$ (103,385)	$ -
3	Purchased Power Expense	Note 1	$000s	$ (54,970)	$ (54,970)	$ (54,970)	$ -
4	Revenue Taxes on Line 1 (8.885% statutory rates)		$000s	$ (29,858)	$ (29,833)	$ (29,833)	$ -
5	Last Rate Order Target Annual Revenues	Sum Lines 1 thru 4	$000s	$ 147,832	$ 147,575	$ 147,575	$ -
6	Authorized RAM Revenues - Transmittal No. 17-04	Sch. A, line 4	$000s	$ -	$ -	$ -	$ -
7	Less: Revenue Taxes on Line 6 at 8.885%		$000s	$ -	$ -	$ -	$ -
8	Net RAM Adjustment - Test Year +5	Lines 6 + 7	$000s	$ -	$ -	$ -	$ -
9	Authorized RAM Revenues - Transmittal No. 18-03	Sch. A, line 4	$000s	$ -	$ -	$ -	$ -
10	Less: Revenue Taxes on Line 9 at 8.885%		$000s	$ -	$ -	$ -	$ -
11	Net RAM Adjustment - Test Year +5	Lines 9 + 10	$000s	$ -	$ -	$ -	$ -
12	Authorized RAM Revenues - Transmittal No. 19-03	Sch. A, line 4	$000s	$ -	$ 2,694	$ 2,694	$ -
13	Less: Revenue Taxes on Line 12 at 8.885%		$000s	$ -	$ (239)	$ (239)	$ -
14	Net RAM Adjustment - Test Year +5	Lines 12 + 13	$000s	$ -	$ 2,455	$ 2,455	$ -
15	Authorized MPIR Revenues - GRID MOD	Schedule L	$000s	$ -	$ -	$ -	$ [redacted]
16	Less: Revenue Taxes on Line 15 at 8.885%		$000s	$ -	$ -	$ -	$ [redacted]
17	Net MPIR Adjustment	Lines 15 + 16	$000s	$ -	$ -	$ -	$ [redacted]
16	Less: EARNINGS SHARING REVENUE CREDITS:	Sch A, Ln 5	$000s	$ -	$ -	$ -	$ -
17	Less: Revenue Taxes on Line 16 at 8.885%		$000s	$ -	$ -	$ -	$ -
18	Net Earnings Sharing Revenue Credits	Lines 16 + 17	$000s	$ -	$ -	$ -	$ -
19	Less: PERFORMANCE INCENTIVE MECHANISM	Sch A, Ln 6	$000s	$ -	$ (395)	$ (395)	$ -
20	Less: Revenue Taxes on Line 19 at 8.885%		$000s	$ -	$ 35	$ 35	$ -
21	Net Performance Incentive Mechanism	Lines 19 + 20	$000s	$ -	$ (360)	$ (360)	$ -
22	Less: 2017 Tax Reform Act Adjustment (1/1/18-5/31/18)	Transmittal No. 18-03	$000s	$ (2,769)	$ -	$ -	$ -
23	Less: Revenue Taxes on Line 22 at 8.885%		$000s	$ 246	$ -	$ -	$ -
24	Net 2017 Tax Reform Act Adjustment	Lines 22 + 23	$000s	$ (2,523)	$ -	$ -	$ -
25	Add: OBF Program Implementation Costs:	Sch A, Ln 1a x 1.0975	$000s	$ -	$ 198	$ 198	$ -
26	Less: Revenue Taxes on Line 25 at 8.885%		$000s	$ -	$ (18)	$ (18)	$ -
27	Net OBF Program Implementation Costs	Lines 25 + 26	$000s	$ -	$ 181	$ 181	$ -
28	Less: PUC-ORDERED MAJOR OR BASELINE CAPITAL CREDITS:	Sch A, Ln 7	$000s	$ -	$ (10)	$ (10)	$ -
29	Less: Revenue Taxes on Line 28 at 8.885%			$ -	$ 1	$ 1	$ -
30	Net PUC-Ordered Major or Baseline Capital Credits	Lines 28 + 29		$ -	$ (9)	$ (9)	$ -
31	Total Annual Target Revenues						
32	August 23, 2018 Annualized Revenues with Interim Increase	column (c)	$000s	$ 145,310			
33	June 1, 2019 Annualized Revenues + 2019 RAM Revenues	column (d), (e)	$000s		$ 149,842	$ 149,842	
34	June 1, 2020 Annualized Revenues w/RAM Increase & MPIR accrued 1/1/21	column (f)	$000s				$ [redacted]
							Note 3
35	Distribution of Target Revenues by Month in Dollars:	Note 2		**2019**	**2019**	**2020**	**2021**
36	January	8.38%		$12,176,939		$12,556,760	[redacted]
37	February	7.50%		$10,898,215		$11,238,151	
38	March	8.06%		$11,711,948		$12,077,266	
39	April	7.85%		$11,406,798		$11,762,598	
40	May	8.18%		$11,886,320		$12,257,076	
41	June	8.19%			$12,272,060		
42	July	8.77%			$13,141,144		
43	August - Interim Rates 8/23/18	9.00%			$13,485,781		
44	September	8.50%			$12,736,571		
45	October	8.73%			$13,081,207		
46	November	8.30%			$12,436,887		
47	December	8.54%			12,796,507		
48	Total Distributed Target Revenues	100.00%		$58,080,220	$89,950,157	$59,891,851	

Footnotes:

1 Columns (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.
Columns (d)-(e): Per the preliminary revenue requirement calculation based on Decision and Order No. 36219, March 18, 2019, Docket No. 2017-0150. See Attachment 4 to this transmittal

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.

3 For illustration purposes only - MPIR Revenue accrual starting January 1, 2021 filed in Transmittal xx-xx, filed Month Day, Year.

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

Line No.	Description	Reference	Amount $000
	(a)	(b)	(c)
1	Grid Modernization Strategy (GMS) - Phase 2	Schedule L1	$ [redacted]
2	Docket No. xxxx-xxxx		
3	Revenue Tax Factor (1/(1-8.885%))		1.0975
4	**Major Project Interim Recovery Total**		$
			To Sch B1, line 15

Note: Per Notice Transmittal to Update Target Revenue for Grid Modernization Strategy (GMS) through the Major Project Interim Recovery Adjustment Recovery Mechanism, filed Month Day, Year, Transmittal No. xx-xx effective January 1, 2021. See Schedule L1.

To the extent that recovery via the test year varies from actual costs incurred, a MPIR true-up adjustment will be made no later than the next annual MPIR true-up filing.

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MAUI ELECTRIC COMPANY, LTD.
DECOUPLING CALCULATION WORKBOOK
REVENUE REQUIREMENT AND DETERMINATION OF MAJOR PROJECT INTERIM RECOVERY
ILLUSTRATIVE MPIR PROJECT - Grid Modernization Strategy (GMS) - Phase 2
$ in thousands

Line No.	Description	Reference	Recorded at 12/31/2020	2021 Activity	Ending Balance as of 12/31/21	Average Balance	MPIR
	(a)	(b)	(c)	(d)	(e)	(f)=((c)+(e))/2	(g)
	Return on Investment - Grid Modernization Strategy (GMS)						
1	Plant in Service (not to exceed PUC approved amount)	As applicable	-	-	-	-	
2	Accum Depreciation	As applicable	-	-	-	-	
3	Net Cost of Plant in Service		-	-	-	-	
4	ADIT	As applicable	-	-	-	-	
5	State ITC & RETITC	As applicable	-	-	-	-	
6	Total Deductions		-	-	-	-	
7	Total Rate Base		$ -	$ -	$ -	-	
8	Average Rate Base					$ -	
9	Rate of Return (grossed-up for income taxes, before revenue taxes)					9.47%	
10	Annualized Return on Investment (before revenue taxes)						$ -
11	Depreciation Expense (Note 1)	As applicable				-	
12	Operating & Maintenance Expense	Note 2				[redacted]	
12a	Prior year reconciliation of O&M to actuals	Note 2				-	
13	Amortization of State ITC & RETITC	see line 5				-	
14	Lease Rent Expense	Not Applicable				-	
15	Other Expense	Not Applicable				-	
16	Total Expenses						$ [redacted]
17	Total Major Project Interim Recovery						$ [redacted]
18	Revenue Tax Factor (1/(1-8.885%))						1.0975
19	Annualized Revenue for Major Project Interim Recovery						$ [redacted]
							To Sch L

Reconciliation to Schedule B1 (Info Only)

	2021
Annualized Revenue for MPIR	$ [redacted]
Rev Tax Adj	$ [redacted]
Prorated MPIR for Year 1 excl Rev Tax	$ [redacted]
Incremental	$ [redacted]

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: O&M expense represents actual pre-implementation O&M expenses incurred in 2020 for outside services to conduct Job Task Analysis and Job Role Impact Analysis to identify risk and change factors and gaps so that the companies can then develop the necessary competence training and curriculum for using the ADMS. Job Positions may also be redefined. See Exhibit D - Interim Recovery of the Application.

Confidential Information Deleted
Pursuant to Protective Order No. _______________

SCHEDULE B1
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HAWAII ELECTRIC LIGHT COMPANY, INC.
DECOUPLING CALCULATION WORKBOOK
ILLUSTRATIVE - DETERMINATION OF TARGET REVENUES

Line	Description	Reference		Docket No. 2015-0170 Amounts	Docket No. 2015-0170 Amounts	Docket No. 2015-0170 Amounts	Note 4 ILLUSTRATIVE Effective 1/1/2021 (GMS)
	(a)	(b)		(c)	(d)	(e)	(f)
1	Last Rate Case Annual Electric Revenue at Approved Rate Levels	Note 1	$000s	$ 289,771	$ 289,771	$ 289,771	$ -
2	Less: Fuel Expense	Note 1	$000s	$ (45,996)	$ (45,996)	$ (45,996)	$ -
3	Purchased Power Expense	Note 1	$000s	$ (72,438)	$ (72,438)	$ (72,438)	$ -
4	Revenue Taxes on Line 1 (8.885% statutory rates)		$000s	$ (25,746)	$ (25,746)	$ (25,746)	$ -
5	Last Rate Order Target Annual Revenues	Sum Lines 1 thru 4	$000s	$ 145,591	$ 145,591	$ 145,591	$ -
6	Add: Authorized RAM Revenues - Incremental 2017 RAM	Note 3	$000s	$ -	$ -	$ -	$ -
7	Less: Revenue Taxes on Line 6 at 8.885%		$000s	$ -	$ -	$ -	$ -
8	Net RAM Adjustment - Test Year +6	Line 6 + 7	$000s	$ -	$ -	$ -	$ -
9	Authorized RAM Revenues - Transmittal No. 18-02	Note 3a	$000s	$ 6,577	$ -	$ -	$ -
10	Less: Revenue Taxes on Line 9 at 8.885%		$000s	$ (584)	$ -	$ -	$ -
11	Net RAM Adjustment - Test Year +2	Line 9 + 10	$000s	$ 5,992	$ -	$ -	$ -
12	Authorized RAM Revenues - Transmittal No. 19-02	Schedule A, Line 4	$000s	$ -	$ 7,670	$ 7,670	$ -
13	Less: Revenue Taxes on Line 9 at 8.885%		$000s	$ -	$ (681)	$ (681)	$ -
14	Net RAM Adjustment - Test Year +3	Line 12 + 13	$000s	$ -	$ 6,988	$ 6,988	$ -
15	Authorized MPIR Revenues - GRID MOD	Schedule L	$000s	$ -	$ -	$ -	$ [redacted]
16	Less: Revenue Taxes on Line 12 at 8.885%		$000s	$ -	$ -	$ -	$ [redacted]
17	Net MPIR Adjustment	Line 15 + 16	$000s	$ -	$ -	$ -	$ [redacted]
18	Less: EARNINGS SHARING REVENUE CREDITS	Schedule A, Line 5	$000s	$ -	$ -	$ -	$ -
19	Less: Revenue Taxes on Line 15 at 8.885%		$000s	$ -	$ -	$ -	$ -
20	Net Earnings Sharing Revenue Credits	Line 18 + 19	$000s	$ -	$ -	$ -	$ -
21	Less: PERFORMANCE INCENTIVE MECHANISM REWARD (PENALTY)	Schedule A, Line 6	$000s	$ -	$ (15)	$ (15)	$ -
22	Less: Revenue Taxes on Line 24 at 8.885%		$000s	$ -	$ 1	$ 1	$ -
23	Net Performance Incentive Mechanism	Lines 21 + 22	$000s	$ -	$ (14)	$ (14)	$ -
24	Less: 2016 TEST YEAR FINAL D&O REFUND	Schedule A, Line 7	$000s	$ -	$ (74)	$ (74)	$ -
25	Less: Revenue Taxes on Line 27 at 8.885%		$000s	$ -	$ 7	$ 7	$ -
26	Net 2016 Test Year Final D&O Refund	Lines 24 + 25	$000s	$ -	$ (67)	$ (67)	$ -
27	Add: OBF PROGRAM IMPLEMENTATION COSTS	Schedule A, Line 1a * 1.0975	$000s	$ -	$ 237	$ 237	$ -
28	Less: Revenue Taxes on Line 21 at 8.885%		$000s	$ -	$ (21)	$ (21)	$ -
29	Net Earnings Sharing Revenue Credits	Lines 27 + 28	$000s	$ -	$ 216	$ 216	$ -
30	PUC-ORDERED MAJOR OR BASELINE CAPITAL CREDITS:	Sch A, Line 8	$000s	$ -	$ -	$ -	$ -
31	Total Annual Target Revenues						
32	June 1, 2018 Annualized Revenues + RAM Increase	column (c)	$000s	$ 151,583			
33	June 1, 2019 Annualized Revenues + RAM Increase	column (d), (e)	$000s		$ 152,714	$ 152,714	
34	June 1, 2020 Annualized Revenues w/RAM Increase & MPIR accrued 1/1/21	column (f)	$000s				$ [redacted]

Line	Description	Note 2	2019	2019	2020	Note 4 2021
35	Distribution of Target Revenues by Month:					
36	January	8.437%	$ 12,789,089		$ 12,884,457	$ [redacted]
37	February	7.898%	$ 11,972,055		$ 12,061,330	$ [redacted]
38	March	8.410%	$ 12,748,162		$ 12,843,224	$ [redacted]
39	April	8.072%	$ 12,235,810		$ 12,327,051	$ [redacted]
40	May	8.292%	$ 12,569,293		$ 12,663,022	$ [redacted]
41	June	8.081%		$ 12,340,796		$ [redacted]
42	July	8.630%		$ 13,179,194		$ [redacted]
43	August	8.764%		$ 13,383,830		$ [redacted]
44	September	8.213%		$ 12,542,378		$ [redacted]
45	October	8.548%		$ 13,053,969		$ [redacted]
46	November	8.263%		$ 12,618,735		$ [redacted]
47	December	8.392%		$ 12,815,735		$ [redacted]
48	Total Distributed Target Revenues	100.00%	$ 62,314,409	$ 89,934,637	$ 62,779,084	$ [redacted]

Footnotes:

1 Col. c: Interim Decision and Order No. 34766, Exhibit A, page 1, issued August 21, 2017, in Docket No. 2015-0170.
Col. d, e, f, g, h: Order No. 35419 Granting Motion to Adjust Interim Increase, issued on April 24, 2018 in Docket No. 2015-0170. Target Revenue calculation is provided in HELCO Revision to Exhibits in Motion to Adjust Interim Increase, Exhibit 14, page 2 of 2 filed April 10, 2018. Approved in Final Decision and Order No. 35559, filed June 29, 2018.

2 HELCO RBA Provision Tariff effective August 31, 2017 based on 2016 test year, filed on July 30, 2018 in Docket No. 2015-0170. The Commission approved the final tariff sheets in Order No.

3 See Letter to Commission, Subject: Interim Increase Tariff Sheets, Exhibit E, Line 4 filed August 23, 2017. See also Exhibit 1, page 95 of the Settlement Agreement filed on July 11, 2017 for details explaining this incremental increase to the 2016 test year related to the 2017 RAM Revenue Adjustment.

3a Transmittal 18-02 filed May 29, 2018, establishing 2018 target revenue effective June 1, 2018.

4 For illustration purposes only - MPIR Revenue accrual starting January 1, 2021 filed in Transmittal xx-xx, filed Month Day, Year.

HAWAII ELECTRIC LIGHT COMPANY, INC.
DECOUPLING CALCULATION WORKBOOK
ILLUSTRATIVE MAJOR PROJECT INTERIM RECOVERY

Line No.	Description	Reference	Amount $000
	(a)	(b)	(c)
1	Grid Modernization Strategy (GMS) - Phase 2	Schedule L1	$ [redacted]
2	Docket No. xxxx-xxxx		
3	Revenue Tax Factor (1/(1-8.885%))		1.0975
4	**Major Project Interim Recovery Total**		$ [redacted]
			To Sch B1, line 15

Note: Per Notice Transmittal to Update Target Revenue for Grid Modernization Strategy (GMS) through the Major Project Interim Recovery Adjustment Recovery Mechanism, filed Month Day, Year, Transmittal No. xx-xx effective January 1, 2021. See Schedule L1.

To the extent that recovery via the test year varies from actual costs incurred, a MPIR true-up adjustment will be made no later than the next annual MPIR true-up filing.

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HAWAII ELECTRIC LIGHT, INC.
DECOUPLING CALCULATION WORKBOOK
REVENUE REQUIREMENT AND DETERMINATION OF MAJOR PROJECT INTERIM RECOVERY
ILLUSTRATIVE MPIR PROJECT - Grid Modernization Strategy (GMS) - Phase 2
$ in thousands

Line No.	Description	Reference	Recorded at 12/31/2020	2021 Activity	Ending Balance as of 12/31/21	Average Balance	MPIR
	(a)	(b)	(c)	(d)	(e)	(f)=((c)+(e))/2	(g)
	Return on Investment - Grid Modernization Strategy (GMS)						
1	Plant in Service (not to exceed PUC approved amount)	As applicable	-	-	-	-	
2	Accum Depreciation	As applicable	-	-	-	-	
3	Net Cost of Plant in Service		-	-	-	-	
4	ADIT	As applicable	-	-	-	-	
5	State ITC & RETITC	As applicable	-	-	-	-	
6	Total Deductions		-	-	-	-	
7	Total Rate Base		$ -	$ -	$ -	-	
8	Average Rate Base					$ -	
9	Rate of Return (grossed-up for income taxes, before revenue taxes)					9.47%	
10	Annualized Return on Investment (before revenue taxes)						$ -
11	Depreciation Expense (Note 1)	As applicable				-	
12	Operating & Maintenance Expense	Note 2					
12a	Prior year reconciliation of O&M to actuals	Note 2				-	
13	Amortization of State ITC & RETITC	see line 5				-	
14	Lease Rent Expense	Not Applicable				-	
15	Other Expense	Not Applicable				-	
16	Total Expenses						$
17	Total Major Project Interim Recovery						$
18	Revenue Tax Factor (1/(1-8.885%))						1.0975
19	Annualized Revenue for Major Project Interim Recovery						$
							To Sch L

Reconciliation to Schedule B1 (Info Only)

	2021
Annualized Revenue for MPIR	$
Rev Tax Adj	$
Prorated MPIR for Year 1 excl Rev Tax	$
Incremental	$

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: O&M expense represents actual pre-implementation O&M expenses incurred in 2020 for outside services to conduct Job Task Analysis and Job Role Impact Analysis to identify risk and change factors and gaps so that the companies can then develop the necessary competence training and curriculum for using the ADMS. Job Positions may also be redefined. See Exhibit D - Interim Recovery of the Application.

Exhibit J

GMS Phase 2 ADMS Application

Glossary of Terms

Note: This glossary is provided to clarify industry and technology terms, leveraging the glossary used in the final Grid Modernization Strategy, *Modernizing Hawai‘i’s Grid For Our Customers*, filed August 26, 2017, in Docket No. 2017-0226.

GLOSSARY OF TERMS

A

Active Network Management (ANM)

In electricity distribution circuits, **Active Network Management** (ANM) describes control systems that manage generation and load for specific purposes. This is usually done to keep system parameters (voltage, power, phase balance, reactive power and frequency) within predetermined limits.

Advanced Distribution Management Systems (ADMS)

Software platforms that integrate numerous operational systems, provide automated outage restoration, and optimize distribution grid performance. ADMS components and functions can include distribution management system (DMS); outage management system (OMS), Switching Order Management (SOM), Distribution Power Flow (DPF), Distribution State Estimation (DSE), automated Fault Location, Isolation, and Service Restoration (FLISR); Conservation Voltage Reduction (CVR); and volt-var optimization (VVO).

Advanced Meter

Meters capable of two-way communication, advanced power measurement, computing platform, outage and service quality information, service switch.

Advanced Metering Infrastructure (AMI)

An integrated system of smart meters, communications networks, and data management systems that enables two-way communication between utilities and customers.

B

Battery Energy Storage Systems (BESS)

A system used to store electrical energy that is capable of retaining energy, storing the energy for a period of time and delivering the energy in the form of electricity after storage.

C

Community-Based Renewable Energy (CBRE)

Programs that allow customers who do not or cannot own rooftop solar panels to participate in community-based programs. Customers who participate purchase interests in the electricity generated by a developer and receive monthly credit from the utility for their portion of the electricity produced.

Customer Average Interruption Duration Index (CAIDI)

Measure of outage duration for customers who experience an outage

Customer Grid-Supply Plus (CGS+)

This program allows customers to export electricity from their own private sources (such as rooftop solar) to the grid and gives customers a monthly bill credit against the cost of the energy customers pull from the grid.

Customer Information System (CIS)

The repository of customer data required for billing and collection purposes. CIS is used to produce bills from rate or pricing information and usage determinants from meter data collection systems and/or manual processes.

Customer Service Representative (CSR)

A company representative that interacts with the customer on various subjects related to the services of the company.

D

Damage Management

A module that assists field personnel who collect information on the location and types of damage observed in the field. The collected information is used in the ADMS to assist in making better assignments of crews, determining the equipment that is required for repair and also make better estimates of restoration times. Sometimes also called Damage Assessment.

Decentralized Energy Management System (“DEMS”)

The DEMS is the name of the product that was approved in the Demand Response Management System (“DRMS”) docket

Demand Response (DR)

Programs to incentivize modification of customer electricity usage to align with available supply (e.g., direct load control, Fast DR, and Energy Scout), including dynamic rate structures (e.g., Time of Use); currently operating under a two-year program and budget-approval cycle.

Demand Response Management System (DRMS)

A software solution used to administer and operationalize DR aggregations and programs. Building on a legacy of telephone calls requesting load reduction, DRMS uses a one-way or two-way communication link to effect control over and gather information from enrolled systems, including some commercial and industrial loads, and residential devices such as pool pumps, air conditioners and water heaters. DRMS allows DR capacity to be scaled in a cost-effective manner by automating the manual events that are typically used to execute DR events, as well as most aspects of settlement.

Distribution Automation (DA)

An intelligent distribution system that uses a network of sensors, controls, switches and communication devices to perform distribution system functions.

Distributed Energy Resource (DER)

Includes distributed generation resources, distributed energy storage, demand response, energy efficiency and electric vehicles that are connected to the electric distribution power grid and behind-the-meter at a customer's premises.

Distributed Energy Resource (DER) Aggregator

A third-party service that works with customers to put together resources and provide grid services.

Distributed Energy Resource Management System (DERMS)

A software-based solution that increases an operator's real-time visibility into the status of DER, and allows for the heightened level of control and flexibility necessary to optimize DER and distribution grid operation. A DERMS can also be used to monitor and control DER aggregations, forecast DER capability, and communicate with other enterprise systems and DER aggregators.

Distributed Generation (DG)

An industry term that refers to a small generator located at or near where the electricity will be used and is attached to the distribution grid. DG can be either a primary or secondary source of power and uses a variety of technologies, such as combustion turbines, solar rooftop panels, and wind turbines.

Distribution Operations Center (DOC)

A DOC is the physical location for distribution operators to interface with management systems like DMS, OMS, GIS, and DERMS in order to manage the distribution system with situational awareness data and substation and distribution automation technologies.

Distribution Operator's Training Simulator (DOTS)

A module that simulates the behavior of the distribution system and other external inputs to an ADMS that mimics real responses to user's actions to assist in the training of distribution operators. Simulated scenarios can include faults, planned outages and storms.

Dispatcher's Power Flow or Distribution Power Flow (DPF)

An analysis application that calculates power system operating conditions including voltage and line flows given a system model, and either real-time measurements or forecast generation and load. For Distribution, the DPF algorithm must also be unbalanced to take into account that the system loads, generation and model cannot be assumed to be identical on all three phases.

Distribution State Estimation (DSE)

A module of an ADMS that provides estimation of the entire voltage and power flow state of distribution system using real-time measurements from SCADA and pseudo measurements such as estimated load and distribution generation.

E

Electric Vehicle (EV)

An EV refers to automobiles and other transportation vehicles that use an electric motor for propulsion, rather than a gas or diesel-burning engine.

Electrification of Transportation (EoT)

Part of Hawai'i's strategic renewable resource goals is to increase the number of electric vehicles and severely reduce the use of personal vehicles that rely on fossil fuels. The Companies released their Electrification of Transportation Strategic Roadmap on March 28, 2018.

Energy Management System (EMS)

A System Operations tool to monitor and manage the electrical transmission system.

Estimated Restoration Time (ERT)

An estimate of the time until an outage is restored based upon known conditions, including time of day, number of crews on duty, outage prioritization rules, and size of outages. ERTs are calculated by an ADMS and are provided as a customer service. Outage management functions of an ADMS help maintain individual and global estimates of restoration times. Also sometimes called Estimated Restoration Time (ERT).

F

Fault Location Analysis (FLA)

A module of an ADMS that uses measurements of fault current and a circuit impedance model to identify the distance from the source and thus one or more probable location(s) of a fault.

Fault Location, Isolation, and Service Restoration (FLISR)

Includes the automatic sectionalizing, restoration and reconfiguration of circuits. This module coordinates operation of field devices to automatically determine the location of a fault, and rapidly reconfigure the flow of electricity so that some or all customers can avoid experiencing sustained outages. FLISR may also be known as Fault Detection, Isolation and Restoration (FDIR).

Field Area Network (FAN)

The second level of a tiered utility communications structure connecting distribution substations and field devices such as field routers.

G

Geospatial Information System (GIS)

A system used to capture, manage and display data in a geographical format.

Greenhouse Gases (GHG)

A gas that absorbs radiant energy within the thermal infrared range, e.g., carbon dioxide and chlorofluorocarbons.

Grid Modernization Strategy (GMS)

A plan submitted by the Companies in August 2017 that lays out near-term actions to build the foundation for meeting the State's RPS goals by 2045 while preserving the flexibility needed to adapt to future advances in technology, changes in policy, and reductions in development costs. See Docket No. 2017-0226, *Modernizing Hawai'i's Grid For Our Customers*, filed August 29, 2017.

H

Hawaiian Electric Companies (the Companies)

Hawaiian Electric Company, Inc. (HECO), Hawai'i Electric Light Company, Inc. (HELCO), and Maui Electric Company, Limited (MECO), are collectively referred to herein as "Hawaiian Electric Companies" or "the Companies."

Hosting Capacity ("HC")

Hosting Capacity is an estimate of the amount of private rooftop solar that may be accommodated on a distribution circuit without adversely impacting power quality or reliability under current configurations and without requiring infrastructure upgrades.

I

Information Technology ("IT") and Operational Technology (OT)

Information technology (IT) is the use of computers to store, retrieve, transmit, and manipulate data, or information, often in the context of a business or other enterprise. Operational Technology is hardware and software that detects or causes a change through the direct monitoring and/or control of physical devices, processes and events in the enterprise. Historically, information technology and operational technology have developed along separate paths, with separate goals, and operating in separate arenas. IT/OT integration is happening across numerous sectors and industries. With the increasing sophistication and application of smart grid technologies in the electrical distribution industry, IT applications can now work in tandem with OT applications to increase distribution system performance.

Institute for Electrical and Electronics Engineers (IEEE)

A professional association for electrical engineers and associated disciplines.

Integrated Grid Planning (IGP)

A customer-centric planning process involving stakeholders, subject matter experts, and technical advisors to identify resources to meet future resource, transmission, and distribution needs with minimal risk and maximum customer value; operates on a two-year cycle starting in 2019.

Integrated Resource Plan (IRP)

An umbrella planning proceeding by the California Public Utilities Commission to evaluate system needs and customer priorities during procurement processes to ensure that power generation meets environmental targets while providing a safe and reliable power supply.

Inter-control Center Communications Protocol (ICCP)

An industry standard communications protocol commonly used to connect SCADA, EMS and ADMS solutions.

L

M

Major Event Days (MED)

An industry standard definition from the IEEE Working Group on System Design that identifies periods of outlying performance, otherwise known as Major Event Days or MEDs. This is commonly used in the calculation of reliability metrics including SAIDI.

Major Project Interim Recovery (MPIR)

A method of recovering capital and deferred project-related costs that align with Commission-issued MPIR Guidelines regarding cost recovery through the designated MPIR adjustment mechanism, as set forth in Order No. 34514, issued April 27, 2017, in Docket No. 2013-0141.

Measurement and Verification (M&V)

Measurement and Verification evaluates the energy performance of a resource. The Measurement and Verification process enables the energy savings delivered by a resource to be isolated and fairly evaluated.

Merchant DER (Fig 5, Exhibit B)

An entity or vendor providing distributed energy resources.

Meter Data Management System (MDMS)

A software system that stores and aggregates the new and future usage data collected from the advanced meters and serves as the system of record for meter configuration information and metered power/usage data. This software is necessary to read the meters and feed the information to the Companies' back office systems.

Meter Data Unification System (MDUS)

MDMS system integration with the CIS billing module utilizing a standardized meter data unification system.

Momentary Average Interruption Frequency Index (MAIFI)

Measure of power interruptions for customers who experience a power interruption

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N

Neighborhood Area Network (NAN)

The third level of a tiered utility communication structure that connects intelligent switches, capacitor banks, advanced meters, and utility managed demand response devices such as A/C cycling devices.

Net Energy Metering (NEM)

A program where excess energy produced by customer-owned renewable energy systems was sent to the electric grid and the customer's account credited using a bi-directional meter system

to register the amount of energy flowing to and from the customer's premises. This program has been replaced by the Customer Grid Supply Plus and Customer Self-Supply programs.

Network Operations Center (NOC)

A physical location to house the hardware and technology of the telecommunications network and allow for network monitoring and control.

Non-Wired Alternatives (NWA)

As has been discussed in the Companies' Integrated Grid Planning activities, NWA's are electricity grid investment or project that uses non-traditional solutions to defer or replace the need for specific equipment upgrades, such as lines or transformers, by reducing load at a substation or circuit level.

O

Outage Management System (OMS)

An OMS utilizes multiple inputs including grid monitoring devices (including advanced meters and line sensors), and customer reports (including telephone calls, and social media posts) to quickly identify outages. Integrating an OMS with other systems like a customer information system can help determine the number of customers affected by an outage and a GIS interface can help identify the likely geographic location of the root cause of an outage.

P

Performance-Based Ratemaking (PBR)

A proceeding opened by the Hawaii Public Utilities Commission on April, 18, 2018 to collectively investigate linking electric utility revenues with utility metrics.

Photovoltaic (PV)

Also known as rooftop solar, PV refers to the method of generating power by converting sunlight into electricity through the use of solar panels.

Power Flow (PF)

See Dispatcher Power Flow (DPF).

Power Supply Improvement Plan (PSIP)

A detailed action plan for the years 2017–2023 that describes the optimal mix of renewable resources and how the Companies can best procure these resources, develop DER programs to support the goal of 100% renewables, and improve grid reliability.

R

Request For Proposal (RFP)

A formal request published for the purposes of soliciting formal proposals from potential vendors to provide hardware, software and services to meet an objective. The RFP includes formal requirements for the proposed vendor to indicate their compliance or non-compliance in the proposed solution.

Renewable Energy Infrastructure Program (REIP)

A program to allow increases to the total base rate charge in order to recover costs of renewable energy infrastructure projects approved by the Public Utilities Commission; reviewed annually to reconcile differences between the costs to be recovered and the revenues received by the surcharge. See the Renewable Energy Infrastructure Program Surcharge approved in the Decision and Order issued on December 30, 2009, in Docket No. 2007-0416.

Renewable Portfolio Standards (RPS)

Upon the enactment of SB 2474 established under Act 95 of the Session Laws of Hawaiʻi in 2004, the Public Utilities Commission can establish standards that proscribe the portions of electricity generation that shall be met by renewable energy sources. For further information on these requirements, see https://www.energy.gov/savings/renewable-portfolio-standard-4.

Request for Proposal (RFP)

The Hawaiian Electric Companies adhere to industry-standard competitive bidding practices as part of the procurement practices established by the Public Utility Commission.

S

SAP Work Orders

A component of the enterprise management system that facilitates work management.

Secondary Var Controllers (SVCs)

SVCs use power electronics-based, fast-acting, decentralized shunt-var technology for voltage regulation. Other types of SVC's both absorb or inject VARs at the circuit level. They can also provide system monitoring capability if a telecommunication path is available.

Smart Grid Foundation Project (SGFP)

A proposal to achieve a more resilient electric grid while meeting the Public Utility Commission's goals for renewable energy standards; ultimately this system-wide approach to grid modernization was deemed to yield insufficient benefits in regard to customer, stakeholder, and utility needs when compared with the project's costs. Instead the Commission requested a

more flexible and incremental approach that resulted in the Grid Modernization Strategy. For more information on the SGFP, see Docket No. 2016-0087, filed March 31, 2016.

Smart Meter

For the purposes of this Application, smart meters, as deployed in the Smart Grid Foundation project's initial phase, are associated with the prior generation of advanced meters.

Switching Order Management (SOM)

A component with the selected ADMS vendor which allows the system operator to create and manage steps utilizing electric grid components to restore customers on outage or to de-energize distribution or transmission circuits for maintenance.

Statement of Work (SOW)

A document that is part of a detailed contract with the vendor that identifies the specific details of the work and the responsible owners for the contracted services.

Supervisory Control and Data Acquisition (SCADA)

A system of remote control and telemetry used to monitor and control the distribution or transmission system and associated substation/feeder automation. D-SCADA refers to SCADA on the distribution system.

System Average Interruption Distribution Index (SAIDI)

Average outage duration for all customers; measured in minutes/hours

System Average Interruption Frequency Index (SAIFI)

Average number of interruptions experienced by all customers (usually per year)

T

Time-of-Use Program (TOU)

A Demand Response program to incentive customers to shift their energy usage to times when solar energy production is at its highest by billing lower electrical rates when demand for electricity is lower.

Trouble Call Management

A module for accepting and recording trouble calls from customers. This includes outage and other trouble conditions.

Trouble Order Management

An outage management function that performs automatic grouping of trouble calls into trouble orders that represent the calls that are likely due to a common cause. Trouble orders can be

sorted by multiple factors for restoration prioritization. Trouble Order Management includes a geographical map display for the System Operator. The OMS then coordinates associated trouble orders through SAP Work Orders to provide specific instruction and coordination to restoration field crews.

U

V

VAR

VAR is the standard abbreviation for volt-ampere-reactive, written "var," which results when electric power is delivered to an inductive load such as a motor.

Volt-Var Optimization (VVO)

A software module that accesses the advanced meter data for both operational/situational awareness and system studies. Also sometimes called Integrated Volt-Var Control (IVVC).

W

Wi-SUN

Wi-SUN is the short form of Wireless Smart Utility Network. The Wi-SUN Alliance promotes adoption of open industry standards used for wireless smart utility and smart city applications to enable interoperability with various vendor distributed energy resource devices. Applications which utilize Wi-SUN wireless networks include advanced metering, distribution automation, municipal lighting, smart parking, environmental sensing, and others.

Wide Area Network (WAN)

The highest level of a tiered utility communications structure connecting the operations centers (main and backup) that house the operational systems, power plants, substations, and data centers.

Exhibit K

GMS Phase 2 ADMS Application

Confidentiality Justification

This log (1) identifies, in reasonable detail, the 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**
Application pages 4, 6, 33, and 34	The Companies' estimated costs associated with the procurement and deployment of components within the Grid Modernization Phase 2 Advanced Distribution Management System (ADMS).	Confidential commercial, vendor, financial and pricing information which falls under the frustration of legitimate government function exception of the Uniform Information Practices Act ("UIPA").[1]	Public disclosure of the confidential information could place the Company at a competitive disadvantage in future contract negotiations; impact the Company's bargaining power relative to its vendors; and could result in the Company paying increased amounts for products and services, thereby increasing costs for the Company and its customers.

[1] Haw. Rev. Stat. § 92F-13(3).

Reference	Identification of Item	Basis of Confidentiality	Harm
Exhibit B, pages 38-42	The Companies' estimated costs associated with the procurement and deployment of components within the Grid Modernization Phase 2 ADMS.	Confidential commercial, vendor, financial and pricing information which falls under the frustration of legitimate government function exception of the UIPA.	Public disclosure of the confidential information could place the Company at a competitive disadvantage in future contract negotiations; impact the Company's bargaining power relative to its vendors; and could result in the Company paying increased amounts for products and services, thereby increasing costs for the Company and its customers.

Reference	Identification of Item	Basis of Confidentiality	Harm
Exhibit D, pages 2,8,11,12,13 and 14	The Companies' estimated costs associated with the procurement and deployment of components within the Grid Modernization Phase 2 ADMS.	Confidential commercial, vendor, financial and pricing information which falls under the frustration of legitimate government function exception of the UIPA.	Public disclosure of the confidential information could place the Company at a competitive disadvantage in future contract negotiations; impact the Company's bargaining power relative to its vendors; and could result in the Company paying increased amounts for products and services, thereby increasing costs for the Company and its customers.

Reference	Identification of Item	Basis of Confidentiality	Harm
Exhibit E, pages 4, 5, 7, and 8	The Companies' Request For Proposal scoring criteria and results associated with the procurement and deployment of the ADMS.	Confidential commercial, vendor, financial and pricing information which falls under the frustration of legitimate government function exception of the UIPA.	Public disclosure of the confidential information could place the Company at a competitive disadvantage in future contract negotiations; impact the Company's bargaining power relative to its vendors; could result in the Company paying increased amounts for products and services, thereby increasing costs for the Company and its customers; harm the Company's relationships with existing and/or prospective vendors and customers; discourage vendors from doing business with the Company and making confidential disclosures to the Company in the future; and infringe upon certain privacy and/or proprietary rights of the Company/employees/vendor.

Reference	Identification of Item	Basis of Confidentiality	Harm
Exhibit E, Attachments 1	The Companies' Request For Proposal documents associated with the procurement and deployment of the ADMS.	Confidential commercial, vendor, financial and pricing information which falls under the frustration of legitimate government function exception of the UIPA.	Public disclosure of the confidential information could place the Company at a competitive disadvantage in future contract negotiations; impact the Company's bargaining power relative to its vendors; could result in the Company paying increased amounts for products and services, thereby increasing costs for the Company and its customers; harm the Company's relationships with existing and/or prospective vendors and customers; discourage vendors from doing business with the Company and making confidential disclosures to the Company in the future; and infringe upon certain privacy and/or proprietary rights of the Company/employees/vendor.

Reference	Identification of Item	Basis of Confidentiality	Harm
Exhibit G, pages 2-4	The Companies' estimated costs associated with the procurement and deployment of components within the Grid Modernization Phase 2 ADMS.	Confidential commercial, vendor, financial and pricing information which falls under the frustration of legitimate government function exception of the UIPA.	Public disclosure of the confidential information could place the Company at a competitive disadvantage in future contract negotiations; impact the Company's bargaining power relative to its vendors; and could result in the Company paying increased amounts for products and services, thereby increasing costs for the Company and its customers.

Reference	Identification of Item	Basis of Confidentiality	Harm
Exhibit H, pages 3,4,5,8, and 9	The Companies' estimated costs and revenue requirements associated with the procurement and deployment of components within the Grid Modernization Phase 2 ADMS.	Confidential commercial, vendor, financial and pricing information which falls under the frustration of legitimate government function exception of the UIPA.	Public disclosure of the confidential information could place the Company at a competitive disadvantage in future contract negotiations; impact the Company's bargaining power relative to its vendors; and could result in the Company paying increased amounts for products and services, thereby increasing costs for the Company and its customers.

Reference	Identification of Item	Basis of Confidentiality	Harm
Exhibit I, pages 1-9	The Companies' estimated costs and revenue requirements associated with the procurement and deployment of components within the Grid Modernization Phase 2 ADMS.	Confidential commercial, vendor, financial and pricing information which falls under the frustration of legitimate government function exception of the UIPA.	Public disclosure of the confidential information could place the Company at a competitive disadvantage in future contract negotiations; impact the Company's bargaining power relative to its vendors; and could result in the Company paying increased amounts for products and services, thereby increasing costs for the Company and its customers.

CERTIFICATE OF SERVICE

I hereby certify that I have this date served two copies of the foregoing APPLICATION OF HAWAIIAN ELECTRIC COMPANY, INC., HAWAI'I ELECTRIC LIGHT COMPANY, INC. AND MAUI ELECTRIC COMPANY, LIMITED, VERIFICATION and EXHIBITS "A"–"K", together with this CERTIFICATE OF SERVICE, by making personal service to the following at the following address:

Dean Nishina
Executive Director
Division of Consumer Advocacy
Department of Commerce and Consumer Affairs
335 Merchant Street, Room 326
Honolulu, Hawai'i 96813

DATED: Honolulu, Hawai'i September 30, 2019.

HAWAIIAN ELECTRIC COMPANY, INC.

Damon L. Schmidt