Hawaiian Electric
Maui Electric
Hawai‘i Electric Light

Modernizing Hawai‘i’s Grid For Our Customers

JUNE 30, 2017

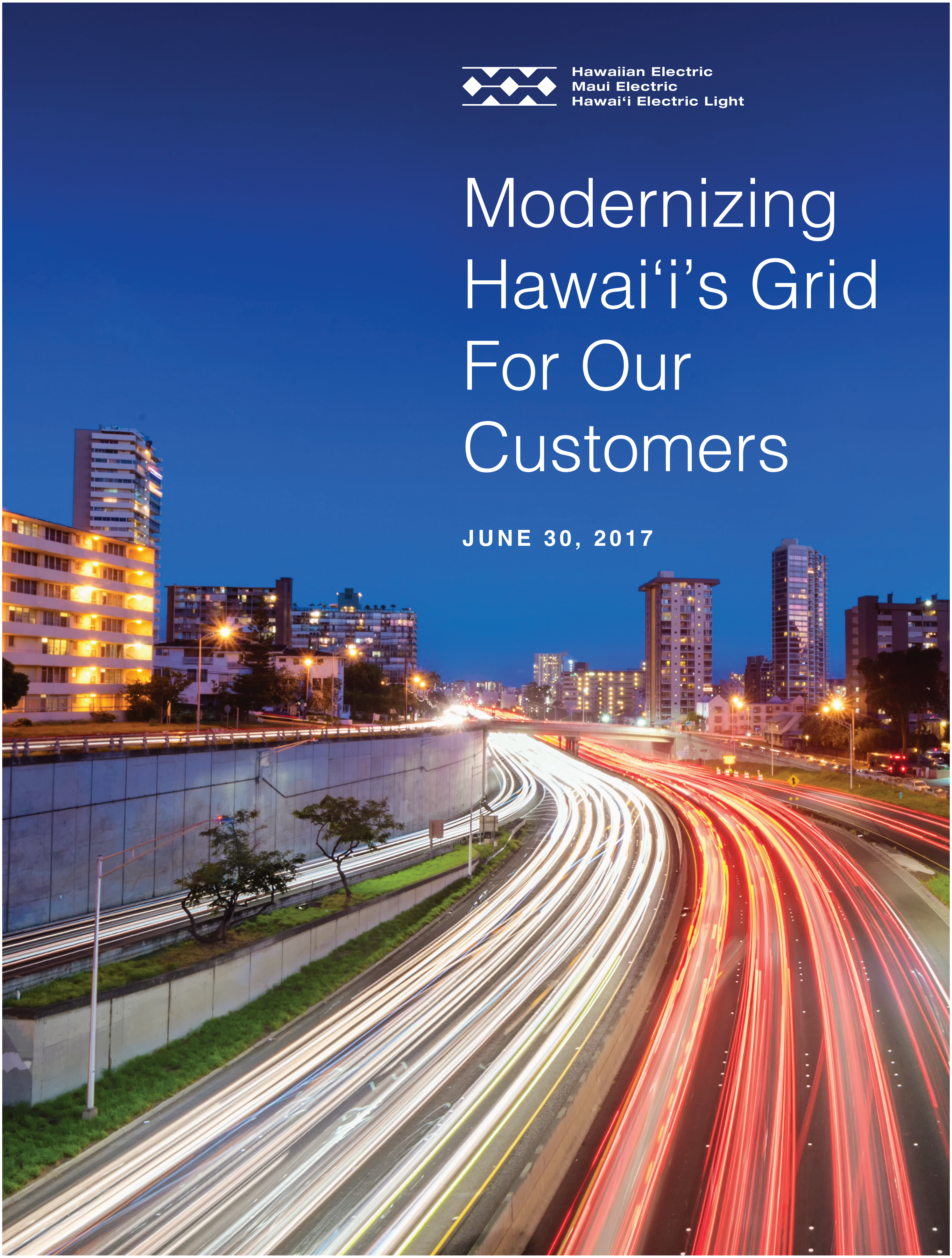

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Table of Contents

List of Figures

List of Tables

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Executive Summary

Hawaiʻi's electric grid is a multilayered delivery system that touches nearly every home and business, a sturdy, secure and safe resource that helps power the state's $75 billion economy.

The grid was originally designed for one job: to deliver electricity to customers from a handful of big power plants. It didn't have to be flexible or adaptable or transparent – it just had to be strong and reliable.

Today, there are power plants in every neighborhood. Nearly 80,000 privately owned rooftop solar systems push electricity onto the grid for delivery to other customers.

The steady, one-way flow of electricity that was the norm for more than a century is now a dynamic, two-way stream of power, shifting back and forth between the customer and the utility. Without real-time data, visibility and control, operators can only estimate how much power these systems are feeding into the grid; they can't manage it and they have no way of "seeing" into circuits to identify and avert situations that can affect the reliable delivery of power to customers.

Built for durability, most of the lines, transformers and substations that are the backbone of the Hawaiian Electric Companies' grids are strong. But these components and others are aging. In addition to the regular schedule of replacement, a program of grid modernization is needed.

New technology will help more than triple the amount of private rooftop solar, make use of rapidly evolving products -including storage and advanced inverters - and incorporate a vast array of sophisticated energy management tools, such as demand response.

This document describes the scope, purpose and estimated cost of the work required to update Hawaiian Electric Companies' energy network in the next six years, and how it will help the five islands served by the company achieve a renewable portfolio standard of 48 percent by 2020 and ultimately 100% by 2045.

Here's what's in it for the customer: Modernizing the electric grid will help get Hawaiʻi off imported oil faster, use technology to predict and avoid outages and to restore service faster and give customers more information and more control over the energy they use.

The cost of the first segment is estimated to be about $205 million over six years. Where appropriate, the Hawaiian Electric Companies plan to pursue partnerships and grants that could reduce the cost.

This needed investment in an advanced grid will be steady and deliberate, aligned with work that's already being done to strengthen the grid infrastructure. With so much new technology arriving, the idea is to focus on near-term improvements that provide the most immediate system and customer benefit but don't crowd out future breakthroughs.

Highlights of this near-term work include:

- Distribution of smart meters "surgically" rather than system-wide, primarily for enhanced sensing and monitoring purposes, i.e., customers with private rooftop solar or on saturated circuits; and to those customers who want to participate in programs such as demand response, variable rates or who seek usage data;
- Reliance on advanced inverter technology to enable greater private rooftop solar adoption;
- Expanded use of voltage management tools, especially on circuits with heavy solar penetration, to maximize circuit capacities for rooftop solar PV and other customer resources;
- Expanded use of sensors and automated controls at the substation and neighborhood circuit level;
- Expansion of a communication network enabling greater operational visibility and efficient coordination of distributed resources, along with smart devices placed on problematic circuits and automation for improved reliability;
- Enhanced outage management and notification technology

A smart power grid can be a catalyst for economic development and sustainable communities, providing everything from energy management services to a solar-powered data center on Hawai‘i Island to reducing voltage fluctuations on a circuit on Moloka‘i so a home-based business can thrive.

A grid that enables variable pricing can also help accelerate the move to electric vehicles and equipment by encouraging charging during the solar peak. Even more important, vehicle batteries and other energy storage devices can provide grid stability – as well as incentives to customers - if system operators can tap these reserves, using stored energy to help meet peak demand and then recharging when solar is abundant.

To develop this grid modernization strategy, the Hawaiian Electric Companies have held discussions since early 2017 with more than 200 people across the state and across the U.S., including engineers, energy experts, utility staff, vendors, technologists and representatives of non-government agencies involved in energy policy.

Also consulted were more than 80 residential and commercial customers of Hawaiian Electric, Maui Electric and Hawaiʻi Electric Light, including some with private rooftop solar. The aim of these discussions was to ensure that the companies addressed customers' "What's in it for me?" question before the grid modernization plan was developed.

Most had only a basic idea of how the grid works, but they were able to clearly describe their expectations (continued high level of reliability), their frustrations (slow transition to renewables) and their needs (stable or lower prices, societal benefit derived from use of renewables, more choices, e.g, private rooftop solar, battery storage, rate incentives).

It was also clear that most customers understand the connection between the pursuit of renewable energy goals and the capabilities of the grid.

One Hawaiian Electric customer observed: "Trying to incorporate renewable energy sources without upgrading the grid is like putting a new kitchen in a house that needs to be knocked down. Why would you do that?"

While the discussion of technical challenges and tactics comprise the bulk of this report, customers' and stakeholders' influences are present throughout. We intend to seek further input from our customers and stakeholders to refine this Grid Modernization Strategy before its final submission at the end of August 2017.

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1 Vision, Definition & Scope

The Hawaiian Electric Companies[1] (the Companies) are committed to partnering with our communities to enable economic growth through reliable, clean, and affordable energy and innovative solutions. As such, we deeply believe that Hawai`i's renewable energy objectives can be met by:

- Empowering customers' choice and providing safe, reliable, and affordable services
- Enabling distributed resources to become a vital part of Hawai`i's renewable portfolio
- Leveraging the electric grid to spur economic growth in our communities

Considering the Hawai`i Public Utilities Commission's (Commission) guidance, input from both customers and stakeholders, and our research, experience, and analysis, the solution to these objectives is very clear: a comprehensive grid modernization strategy – one that is implemented at the right pace, is proportional to both customer and grid needs, and realizes net value and benefits for all customers.

Of course, accomplishing these objectives is not easy. Modernization is like a giant Rubik's cube – the answer is seemingly simple – just get all the squares on each side to be the same color. But, how you actually achieve this result is complicated, as Greentech Media's Grid Edge Cube shows.[2] ***The right strategy is not just the right pieces at the right time at the right level of risk and cost. It also has to be aligned with the needs of customers and stakeholders.***

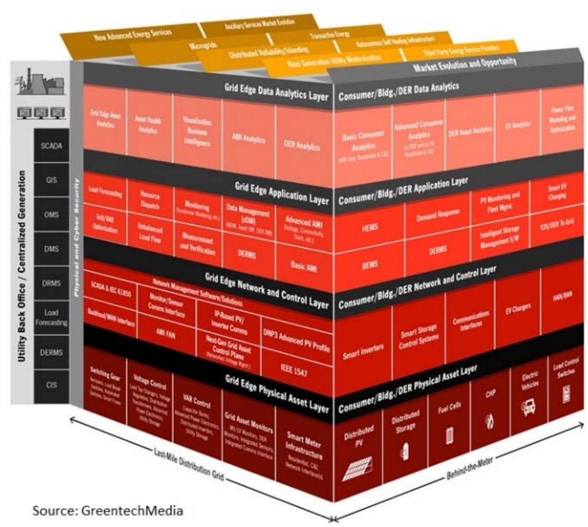

Figure 1 Greentech Media Grid Edge Cube

Many decisions are needed to solve this complex puzzle. A set of principles are necessary to guide decisions in this strategy

[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 herein as "Hawaiian Electric Companies" or "Companies".

[2] Greentech Media, Distributed Solar Power Is Forcing Change at the Grid Edge, March 06, 2014: https://www.greentechmedia.com/articles/read/Distributed-Solar-Power-Forcing-Change-at-The-Grid-Edge

and as we move forward with stakeholders. We are in alignment with the Commission with respect to what a modern grid should achieve and how it should be accomplished. We believe it is essential that we consider integrated grid planning across all aspects of the Companies, community, and grid, including distribution, transmission, and resource planning. Additionally, it is essential that customers appropriately benefit from costs incurred to advance the state's policies and related modernization investments. As such, we propose adapting and expanding the Commission's interpretation of the Hawai`i State Legislature's guiding principles[3] as listed below:

Hawaiian Electric Companies Guiding Principles to Inform Grid Modernization

- Enable greater customer engagement, empowerment, and options for utilizing and providing energy services;
- 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;
- Facilitate comprehensive, coordinated, transparent, and integrated grid planning across distribution, transmission, and resource planning.
- Move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies;
- Ensure optimized utilization of resources and electricity grid assets to minimize total system costs for all customers' benefit;
- Determine fair cost allocation and fair compensation for electric grid services and benefits provided to and by customers and other non-utility service providers

We face a challenge, a rising need to serve customers with affordable and reliable electric service while transforming the system to renewable energy and enabling customers to better control their energy needs. Hawai`i is at a much different starting point for modernization than any other state. In 2016, approximately 26 percent of our combined customers' energy needs were powered by renewable sources, with higher percentages for Maui County and Hawai`i Island of 37 percent and 54 percent, respectively. We continue to lead the nation in the integration of customer-sited private solar, with the highest percentage of customers with solar of any utility in the country. More than 15 percent of our total customers – including an estimated 26 percent of single-family homes – had private solar in place by the end of 2016, with an additional 3 percent of single-family homes approved for installation.

The Companies realize that meeting our customers' needs and achieving our clean energy goals is not possible with our current grid. In other words, ***the grid we have is not the grid we need***.

[3] Hawaii PUC (HPUC) Docket No. 2016-0087, Order No. 34281, Section D "Guiding Principles": http://dms.puc.hawaii.gov/dms/OpenDocServlet?RT=&document_id=91+3+ICM4+LSDB15+PC_DocketReport59+26+A1001001A17A05B01613H2647618+A17A05B31600C464561+14+1960

Hawai`i's success in adopting renewable energy has strained the capacity of our grids. The limitations of our current grid have hampered our ability to integrate more customer-sited resources. Therefore, the grid must transform from one that is designed for one-way power flow from a few central generating stations to one that safely and reliably enables two-way power flow from many resources. The Companies' vision is to use advanced technologies to modernize our existing grid into a state-of-the-art cyber-physical platform[4] that will enable the integration and optimal utilization of customers' resources through existing and new distributed energy resources (DER) and demand response (DR) programs to meet the December 2016 PSIP projections as summarized in Table 1.

Table 1 December 2016 PSIP Projections for Demand Response and Distributed Energy Resources

December 2016 PSIP Projections	2017-2021	2022-2045
New DG-PV	326 MW	2,086 MW
New Customer Self Supply (CSS) Energy Storage	89 MW-hr.	1,057 MW-hr.
New Demand Response Capacity	115 MW	442 MW
New Demand Response Energy Storage	104 MW-hr.	1,608 MW-hr.

A more reliable and resilient grid will ensure that power flows from the edge can contribute to Hawai`i's energy needs and also provide improved service for an "always on" society. Moreover, grid modernization can serve as a catalyst that enables convergence of an integrated electric network with telecommunications, water, and transportation systems to sustainably support a vibrant economy in Hawai`i.

The modernized grid platform should be based on an architecture that enables the right pieces to be added at the right time at the right level of investment. Additionally, modernization should be coordinated with aging infrastructure replacement to thoughtfully align with customer and policy needs in a cost-effective manner. This integrated, modern grid is consistent with the Commission's definition[3]:

> "A modernized grid assures continued safe, reliable, and resilient utility network operations, and enables Hawai`i to meet its energy policy goals, including integration of renewable electricity sources and distributed energy resources. An integrated, modern grid provides for greater system efficiency and greater utilization of grid assets, enables the development of new products and services, provides customers with necessary information and tools to enable their energy choices, and supports a secure, open standards-based and interoperable utility network."

[4] Cyber-Physical systems combine the cyber and physical worlds with technologies that can respond in real time to their environments. Cyber-Physical platforms (including the Internet of Things, Industrial Internet, and more) include co-engineered interacting networks of physical and computational components. From the National Institute of Standards and Technology (NIST): https://www.nist.gov/programs-projects/cyber-physical-systems-program

By working together with customers and stakeholders, the Companies firmly believe that they can improve operational efficiency and reduce the dependence on fossil fuels that contribute to global warming while moving Hawai`i to a sustainable energy future.

This grid modernization strategy (Strategy) is organized around the topics identified and questions raised in the Commission's Order 34281.

- Section 2 summarizes the input and feedback received from customers, key stakeholders and the industry.
- Section 3 describes our architectural view of a modern grid for Hawai`i and our targeted, proportional approach to implementation.
- Section 4 introduces an integrated grid planning process to guide development of resources, including both transmission and distribution, going forward. This section also links planning to a proposed cost-effectiveness framework and its relationship to ratemaking.
- Section 5 summarizes the current state of the Companies' grid modernization efforts and highlights important technical considerations to address in the near term (approximately 5 years).
- Section 6 highlights the overall customer engagement strategy in relation to grid modernization and key technologies proposed over the near-term building on existing solutions.
- Section 7 highlights the grid-facing technology strategy and near-term investments that will enable flexible future scenarios.
- Section 8 provides the near-term grid modernization roadmap along with conceptual cost estimates and a summary comparative assessment of enhanced business-as-usual versus grid modernization alternatives.
- Appendices contain a glossary and additional supporting material.

2 Customer & Stakeholder Engagement

The Companies have engaged and will continue to engage with customers and stakeholders to seek input and feedback on grid modernization. This dialogue is an evolving conversation about customer needs and what it will take to affordably build a reliable grid in pursuit of Hawai`i's energy goals. Meeting these goals involves building a common understanding of the challenges, opportunities, and tradeoffs involved with enhancing the electric grid to meet customer service expectations and achieve the state's renewable goals. That understanding starts with listening to customers and stakeholders.

2.1 CUSTOMER INTERVIEWS AND FOCUS GROUPS

The Companies hired an independent consumer research firm, Ward Research to conduct a series of customer interviews and focus group meetings from a cross-section of commercial and residential customers and community organizations across Hawai`i. These engagements were intended to gain better insight into consumer preferences, priorities, and expectations related to grid modernization. One-on-one interviews and focus groups were held on Hawai`i, Maui, and O`ahu during April and May 2017. Ward Research's full report is included in Appendix B. The Companies plan to obtain additional customer and stakeholder feedback in preparation for the final version to be completed by August 29, 2017.

The hopes and expectations of residential customers align around "what's in it for me". They see a modernized grid as a way to allow more rooftop solar and, ultimately, to reduce cost through the use of this renewable energy source… Reliability is important to all stakeholder audiences, with all expressing relatively high levels of satisfaction with current reliability.

Dramatic differences were seen in the perspectives coming from the energy experts, advocates, and large commercial users and those of residential customers. The hopes and expectations of residential customers align around "what's in it for me." They see a modernized grid as a way to allow more rooftop solar and, ultimately, to reduce cost through the use of this renewable energy source. Even when discussing the integration of "renewable resources" into the grid, residential customers view renewables in terms of rooftop solar and not through a whole-system lens (e.g., wind, biomass, waste to energy, geothermal, etc.). The focus on individual rooftop solar, with information coming from solar

salespeople, the media, and their friends and neighbors, really prevents customers from thinking much further about challenges associated with Hawai`i's renewable energy goals.

The energy experts and advocates, on the other hand, are clearly focused on Hawai`i's goal of 100 percent clean energy. They, too, want to see a greater ability of the grid to incorporate rooftop solar, but they take a broader view of the various resources available. While residential customers tended to express impatience related to less expensive energy and lower bills, the energy stakeholders expressed frustration at the pace of the needed grid modernization, wanting us to be further along than we are now. In the interviews, large commercial users focused their attention on grid stability and flexibility; issues far from the residential user's awareness or consideration.

Reliability is important to all stakeholder audiences, with everyone expressing relatively high levels of satisfaction with current reliability. At the meetings, residential customers struggled with the idea of less (or more) reliability, believing that the utility's job is to provide the maximum reliability possible, such that incremental differences are imperceptible to them. Some of the energy stakeholders were relatively more familiar with the redundancies needed to achieve greater reliability and the associated costs of those redundancies. They believe the utility should be required to provide a threshold level of reliability, such as is provided now, and the customer should bear the cost of any additional needed reliability.

Two videos were shown to residential customers in the focus groups (Two-Way Flow and Grid Ops)[5] and served to educate them about grid management issues, an education that they suggested should be broadly shared with the general population. Prior to viewing the videos, it wasn't uncommon to hear participants refer to "the grid in my neighborhood" without context for the interrelation of the island sectors, or the grid "storing energy to use later." After seeing the videos, participants reported that they had no idea that differing sources of energy had to be balanced or that this is a challenge for the electric companies. They also indicated a better understanding of the challenges associated with "excess" energy. With this new understanding, they were able to engage in deeper discussion about incorporating renewables into the grid, energy storage, and other timely issues reflected in the feedback.

Storage (and particularly battery storage, at present) is seen by all stakeholder groups as the "Holy Grail" of our energy future, to quote one of the energy experts. (It must be noted, however, that some residential customers believe that energy can be stored in the grid currently and used when needed.) Customers across all stakeholder groups want to see utility-grade storage located around each of the islands to help stabilize the grid and increase efficiency, while opinions differed regarding who should pay for this. Most feel that this storage will benefit everyone so the cost should be shared, while others feel this is an expense that should be borne by the utility. However, there are concerns expressed by customers,

[5] Maintaining Safe and Reliable Energy for Customers YouTube Video: https://www.youtube.com/watch?v=QECzuo8WD4I

Managing a Two-Way System to Integrate More Renewable Energy YouTube Video: https://www.youtube.com/watch?v=nH47jRCk5cw

including how they would benefit, if batteries can explode or catch fire, and if there are health hazards related to battery leakage, etc.

Energy experts and larger commercial users are focused on a better understanding of macro-level grid usage patterns and individuals having access to their own usage data. Real-time data, including variable pricing that may change daily, is of great interest to those with an interest in public policy and those able to use sophisticated energy management systems. They see this real-time information as key to increasing energy efficiency and controlling costs. Without specific programs to test, however, residential customers do not express this same interest, nor do they display any awareness of the usefulness of real-time data. As stated earlier, residential customers remain focused on other issues that have (currently) identifiable benefits to them, such as the incorporation of more rooftop solar and features that they believe can reduce their monthly bills.

Hawai`i needs equitable cost allocation and compensation for customers and other non-utility service providers who both provide and receive grid services.

Conversations around who should pay for grid modernization brought out some interesting dynamics. In general, participants across all stakeholder groups believe that the cost of improvements that benefit all users (e.g., efforts that allow for the integration of more renewable energy sources, whether residential rooftop solar, wind turbines, or biomass plants) should be shared by all users. This is seen as approaching a "social justice" issue and "for the greater good." However, this commitment softens when considering those improvements that benefit PV owners only; some customers feel that PV owners are not paying their fair share now. Taking the concept one step further to grid enhancements that can be allocated to the costs of charging electric vehicles (EVs), residential participants were clear that EV owners should pay for these enhancements, given the benefits they enjoy currently (e.g., free charging at public facilities and shopping centers, avoidance of gasoline taxes) and their ability to pay for a "premium" car. In sum, equitable cost allocation and compensation for electric grid services and benefits provided to and by customers and other non-utility service providers is needed.

2.2 STAKEHOLDER ENGAGEMENT

The Companies met directly with several stakeholders at the start of this strategy development to seek general input regarding grid modernization and clarification on several aspects of the Commission's grid modernization strategy Order 34281,[6] including Commission

[6] HPUC Order No. 34281 Dismissing Application Without Prejudice and Providing Guidance for Developing a Grid Modernization Strategy, January 4, 2017 (Order 34281): https://dms.puc.hawaii.gov/dms/OpenDocServlet?RT=&document_id=91+3+ICM4+LSDB15+PC_DocketReport59+26+A1001001A17A05B01613H2647618+A17A05B31600C464561+14+1960

staff, the Consumer Advocate, the Ulupono Initiative and the Hawaii Natural Energy Institute (HNEI).

These stakeholders expressed that customers' needs and feedback were a priority. They agree that grid modernization investments must be cost-effective and proportional to needs, and that the needs should be identified via a transparent planning process. They want needed investments to be prioritized to keep options open for incorporating future technical innovations. While customer affordability is a key consideration, they recognized that grid modernization investments are needed to enable continued customer adoption of DER and state renewable energy policy actions. Therefore, they think it essential for the Companies' strategy and subsequent planning to employ a prioritized, targeted approach for necessary infrastructure investments rather than default system-wide deployments. Longer term, they anticipate the need to strike a balance between distributed and large-scale renewable energy. This balance will be further shaped by resource potential, rates, DER technology innovation, and customer choice. Additionally, stakeholder feedback can be summarized as follows:

- **Need**: Prioritize the investments in the near term.
- **Flexibility**: Keep future options for investments and technology open.
- **Cost**: Balance renewable energy goals with the cost to achieve them.
- **Transparency**: Describe the alternatives considered and decision-making process for selecting grid modernization technologies and solutions.
- **Risk**: Consider technology obsolescence and potential for stranded assets.
- **Fairness**: Consider fair and equitable treatment of customers.

On May 10, 2017, the Companies hosted a Modern Grid Technology & Leading Practices Workshop. Stakeholders, including customers and DER, DR, and PSIP parties, were invited to attend in-person or through an online webinar.[7] The objective was to facilitate the constructive exchange of information on commercially available advanced technologies and leading industry practices for modernizing the electric grid. The workshop involved several panels discussing key topics identified by the Commission in its grid modernization strategy order.[6]

The panel speakers included leading customer-facing and grid-facing technology suppliers as well as leading industry experts on grid modernization from the U.S. Department of Energy (DOE), the Pacific Northwest National Lab (PNNL), the Electric Power Research Institute (EPRI), HNEI and Smart Electric Power Alliance. The workshop attracted over one hundred in-person attendees, with another fifty participating via online webcast.

Workshop discussion reinforced the recognition that Hawai`i is on the leading edge in terms of redesigning electric grids to accommodate very high levels of DER and large-scale renewable resources. However, utilities and regulators around the world have been encountering some of

[7] Hawaiian Electric Companies - Modern Grid Technology & Leading Practices Workshop: http://www.enernex.com/heco-modern-grid-technology-leading-practices-workshop/

the same challenges. This workshop identified several key emerging and leading practices to develop of a modern grid for Hawai`i. The recommended practices that came out of the workshop are as follows:

- Define clear objectives and attributes for the grid
- Develop a grid architecture to address these objectives/attributes that can evolve with technological innovation
- Utilize open standards as an essential aspect reducing implementation costs and achieving interoperability for future flexibility
- Identify and assess the technological and operating innovations that offer the potential for meeting Hawai`i's needs and creating customer value
- Adopt a logical implementation plan based on the architecture that is capable of evolving (i.e., "don't put the windows in first").

The input received from customers, stakeholders, and industry members over the course of the workshop provided useful perspectives to the planning process. The strategy that came out of these discussions and is outlined in this document is responsive to customers' needs, reflects stakeholders' interests, and leverages leading practices across the industry.

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3 Grid Modernization Strategy

The Companies' believe that meeting customer expectations for reliability and increasing DER utilization can be done cost effectively through proportional investment in advanced technology and foundational cyber-physical infrastructure. In other words, we propose a strategy to evolve the grid using advanced technologies at a pace consistent with meeting customer needs and deriving customer value, while remaining flexible to adopt emerging technologies.

3.1 THE GRID WE NEED

As we pursue this customer-centric vision, grid modernization will present opportunities to meet technical challenges encountered as we transform our existing grid over the next 20 or more years:

- **Current**: Significant growth of customer DER (approximately 600 MW across the Companies' service areas) has resulted in overall system and individual circuit penetration levels higher than those experienced in any other part of the world. The rate of growth has outpaced the ability to properly address technical and operational issues at all levels of the grid: bulk generation, transmission, and the distribution system. The rapid change in the operating characteristics of the power system is challenging the operational capability of the system to provide essential services and maintain the reliability of the electric supply in Hawai`i.
- **Near term**: Continued customer DER adoption and use of DER as a grid resource necessitates integration of advanced grid technologies into the distribution system to enable cost-effective DER integration and utilization. The grid will evolve into a conduit for coordinated import and export of energy and related services. Approximately 326 MW of new DER resources, 89 MW-hr. of customer self-supply (CSS) energy storage, and 115 MW of DR resources, including 104 MW-hr. of DR energy storage resources, are expected to be integrated by 2021.[8] This use of the distribution system represents a new paradigm for grid operations and further emphasizes the importance of reliability and operational flexibility.

[8] December 2016 PSIP, at ES-2.

- **Long term**: Extend the integrated grid platform to leverage energy storage, advanced grid technologies, and cyber-physical infrastructure upgrades that can incrementally evolve over time. Such a grid can achieve the goal of 100% renewables by 2045 with grid-scale (approximately 3,000 MW) and distributed resources (approximately 3,000 MW) that are both intermittent and highly variable, as envisioned in the PSIP. Moreover, such a grid would enable the convergence of multiple systems that would create strong economic benefits for communities, businesses, and customers as well as the infrastructure owners.

This customer-centric strategy focuses on the near-term approach for the next five years to ensure flexibility over the longer term to adjust to changing circumstances and technological breakthroughs. To maximize benefits, these nearer term investments must set the foundation to evolve the Companies' grids to meet the changing needs and demands of our customers. This strategy is also tailored to the unique nature of the Companies' infrastructure, including the fact that the system is comprised of relatively small to very small island grids with high DG-PV penetration. Hawai`i also does not have the luxury of being able to rely on neighboring states to make up for generation shortfalls due to high customer demand or export of energy during over supply situations, as do states on the mainland, such as California. Therefore, maintaining and planning around reliability is critically important.

Near term focus to continue building the modern grid and invest in new applications for customer engagement and DER integration

Evolution of the grid is expected to adapt to changes in customer needs, technological developments and other factors over time. To collectively understand the drivers of change and impact on the grid, Section 4 proposes an ongoing integrated grid planning process with stakeholder engagement that holistically addresses resource planning (both bulk and DER), transmission planning, and distribution planning.

3.2 GRID ARCHITECTURE

Grid operational systems are evolving in complexity and scale with the integration and utilization of DER.[9] This evolution increases the need for enhanced functionality related to planning, operations, and support for operational markets. However, this also introduces operational risks in the forms of system complexity and vulnerability to cyber-attack.[10] This

[9] M. McGranaghan, et al., Renewable Systems Interconnection Study: Advanced Grid Planning and Operations, Sandia, 2008: https://www1.eere.energy.gov/solar/pdfs/advanced_grid_planning_operations.pdf

[10] Staff, U.S. DOE Office Of Electricity Delivery And Energy Reliability, Energy Sector Cybersecurity Framework Implementation Guidance, January 2015:

increased complexity goes well beyond what traditional distribution system designs can manage properly. To manage the complexity, a scalable, extensible architectural approach is needed that can address the multiple layers of resources connected at transmission, distribution and behind the meter on the customer's premise. As noted by the Commission in Order 34281,[6] grid architecture is an important part of a grid modernization strategy.

> Grid Architecture is the application of system architecture, network theory, and control theory to the electric power grid.[11]

The Companies have grounded the development of this modernization strategy in the grid architectural approach described by PNNL.[12] Three key aspects for a grid modernization strategy are 1) layered architecture, 2) platforms, and 3) extensibility to enable proportional deployment.

3.2.1 Layered Architecture

Developing a new grid strategy requires the careful, planned review of many factors. It is important to consider DER energy export to the grid, DR programs, and potential for aggregated DER and DR services. We must also consider how they relate to the overall management of the grid, including all existing resources currently connected. With respect to the control architecture of the grid to ensure reliable operations, PNNL notes:

> "As variable and bi-directional power flows increase and DERs provide grid services, there is a need to effectively coordinate this activity. Coordination is the process of ensuring that distributed elements (i.e., grid components, DERs, organizations) collaborate appropriately to solve a common problem. It can involve direct control, markets, or organizational interaction rules, among other things."

A layered architectural approach to operating the grid involves coordination of resources across three layers: customers, distribution, and transmission. The coordination framework that PNNL describes above involves managing the operation of DER with both distribution and transmission systems. This is a distributed, layered architectural approach to developing and operating the grid. A layered approach allows coordinated management of the complexity, security and control interfaces with DER aggregators and 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 will be problematic, as many of these systems have nonstandard interfaces and uncertain cybersecurity protocols.

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https://energy.gov/sites/prod/files/2015/01/f19/Energy%20Sector%20Cybersecurity%20Framework%20Implementation%20Guidance_FINAL_01-05-15.pdf

[11] U.S. DOE, Pacific Northwest National Lab: "Tutorials and Advanced Concepts for Architecture of Electric Power Grids": http://gridarchitecture.pnnl.gov/

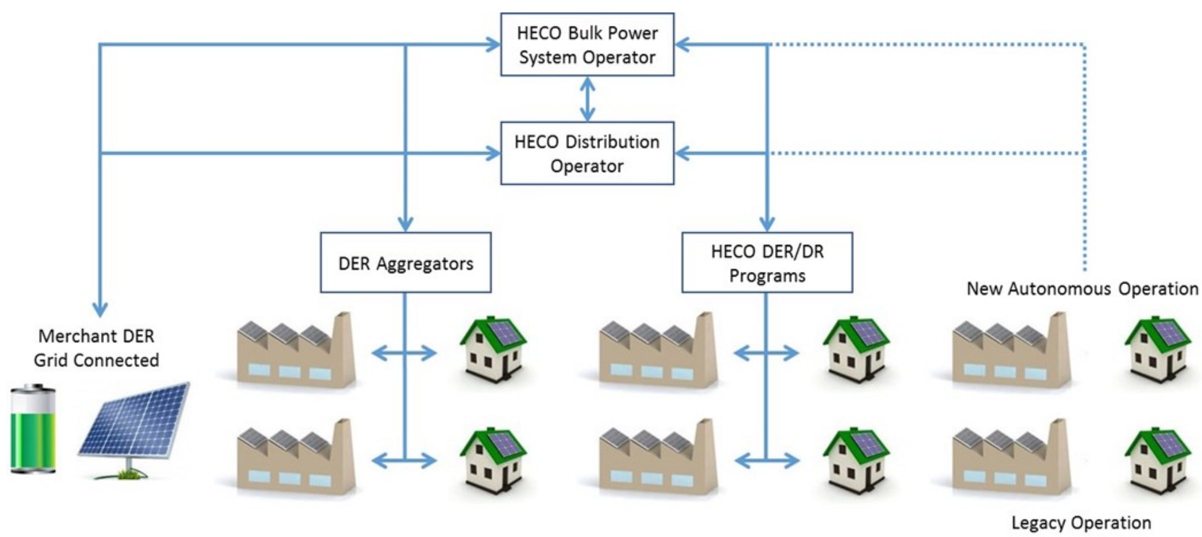
[12] J. Taft and A. Becker-Dippmann. Grid Architecture. PNNL-24044, Pacific Northwest National Laboratory. 2015: http://www.pnnl.gov/main/publications/external/technical_reports/PNNL-24044_2.pdf

Traditional distribution engineering architecture and designs are inadequate to address these issues. Also, information-centric architectures,[13] focusing primarily on information flows, are useful but not sufficient to address the physical aspects of the modern grid. It is the equivalent to having the plumbing design for a house whereas grid architecture is the whole house blueprint. Given these issues, we are proposing to pursue a holistic grid architecture. One key aspect for Hawai`i is the architectural approach for controls. The Companies are pursuing a two-part control strategy. An approach for normal operating conditions to utilize DER as illustrated in Figure 2 and back-up controls to control output of DER to maintain system reliability under abnormal operating conditions – a unique need to Hawai'i's island grids.

Traditional distribution engineering designs and information-centric architectures are insufficient to address all the issues – a holistic grid architecture is required.

Normal Operational Controls

Figure 2 Distributed, Layered Approach for DER



As illustrated in Figure 2 the level of operational control and interfaces involve several different types of DER and controls within a distributed, layered architecture:

- **"Merchant DER"** (or, Independent Power Producers) indicates third-party provider assets directly connected to subtransmission or distribution systems providing services directly to the grid that require direct control and an information interface with grid operations. This is necessary given the anticipated size of merchant resources.

[13] Smart Grid Coordination Group, Smart Grid Reference Architecture, CEN-CENELEC-ETSI, November 2012 https://ec.europa.eu/energy/sites/ener/files/documents/xpert_group1_reference_architecture.pdf

- **"DER Aggregators"** refers to aggregating customer assets to provide services to the grid. For aggregated DER, we do not believe it is necessary to directly control each resource. Rather, we expect to establish and secure an operational interface with each aggregator to share operational instructions and appropriate information.
- **"HECO DER/DR Programs"** indicates where customers participate in the Companies' programs. For those programs that the Companies manage, direct interface with and control of those devices may be needed.
- **"New Autonomous Operation"** indicates post-2016 customers with "advanced inverter" DER who choose not to participate in an aggregator or utility program. Establishing operational standards for DER, such as those being developed in IEEE 1547[14] and as the Companies are proposing in the Commission's DER Investigative Proceeding, Docket No. 2014-0192, will enable autonomous functionality of DER advanced inverters that will not adversely affect the grid. A challenge for the industry is that IEEE 1547 leaves quite a lot of flexibility for manufactures to select different communications and protocols; achieving functional standardization will be difficult.
- **"Legacy Operation"** refers to pre-2016 inverter DER without advanced inverter functionality capabilities such as the expanded frequency and voltage range ride-through. Legacy DER systems will not be directly managed but may require additional investment, especially at the bulk system level, to account for their impacts as more DER is integrated onto the grid.

Abnormal System Reliability Controls

In addition to the normal operational controls described above, there needs to be alternative means of controlling the amount of power being exported into the grid under certain abnormal circumstances that threaten grid reliability and stability. One of the current challenges in accommodating DER at the system level is that, currently, the amount of active power fed-in is not visible or controllable for the grid operator. In the event of an excess generation event at the bulk system level or other conditions that endanger safety or reliability of the grid, other resources must be adjusted. Due to physical operating range limitations of central generators, this needed flexibility may not be possible beyond a certain limit; that is, each island grid has a system hosting capacity, as discussed in Section 5.1.

In the event where generation and load are mismatched and available controllable generation are at their minimum output, the system operator will require visibility and controllability of DER resources in order to maintain grid reliability and stability. If supply and demand cannot be quickly balanced, system frequency[15] could deviate from normal operating ranges, which in extreme circumstances, could result in an island-wide black-out exacerbated by the loss of legacy DER with inverters that trip out of service due to system frequency or voltage

[14] IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems: http://grouper.ieee.org/groups/scc21/1547/1547_index.html

[15] Alternating Current (AC) follows a sinusoidal waveform. In the U.S. IEEE 15477 specifies a desired waveform frequency of 60 Hz.

excursions during these events. This is a situation somewhat unique to island grids like Hawai`i's. The grid operator in California, for example, is able to export the excess to neighboring states during periods of excess energy on the system.[16]

To address system reliability, the Companies in the near-term are taking a multi-pronged approach beyond the normal operational controls described above to enable back-up control of DER needed for system reliability:

- **Advanced Sub-Metering for DER** – In several utility jurisdictions around the nation,[17] including Kauai Island Utility Cooperative, Arizona Public Service (APS), Salt River Project (SRP) and Public Service New Mexico (PNM), a separated (second) advanced meter is used as a metering point for distributed generation. Separating the DER facility from the premise load allows for the utility to directly monitor the generation provided locally much more accurately than current estimation techniques. The advanced meter could also be directly addressed by the utility, allowing the system to be disconnected from the grid temporarily when necessary to manage the electric system. This provides a standard means of control and access with minimal additional infrastructure upgrade beyond that needed for Advanced Metering Infrastructure (AMI). This approach is also technologically possible now without waiting on future technology development and facilitates future growth of exporting DER resources.
- **Remotely Controlled Device** – A few vendors have also introduced "meter collars" as a modification to the traditional meter socket for a net energy metering system. Another solution coming to market is an interconnection device that uses a smart circuit breaker configuration that provides metering, monitoring and control of the interconnected DER. These adapters provide a metering point for exporting DER and the capability to disconnect the systems when necessary.

The Companies expect that this two-part control architecture using primary control methods to manage normal operations and back-up controls for system reliability will be the most cost-effective for customers and aggregators. However, the Companies must retain an option to directly control DER devices if the market fails to satisfy the necessary reliability and security requirements.

[16] California invested heavily in solar power. Now there's so much that other states are sometimes paid to take it: http://www.latimes.com/projects/la-fi-electricity-solar/

[17] Advanced Metering Infrastructure (AMI) for Distributed Solar (PV) Integration: Utility Survey Results. EPRI, Palo Alto, CA: https://www.epri.com/#/pages/product/000000000001019585/

3.2.2 The Grid as a Platform

The grid that Hawai`i needs is a reliable platform that enables the integration of customer DER and the utilization of DER as a system resource. Such a grid can expand value for all customers and serve as a catalyst to convergence of an integrated electric network with other industries.

The grid that Hawai`i needs is based on the concept of a platform that enables the integration of customer DER and the utilization of DER as a system resource. We are applying the concept of a core platform as described by the U.S. DOE[18]:

> "…platform relates to the structure of the cyber-physical grid where certain components remain stable forming the core platform, while other complementary modules are integrated over time through interoperable interfaces. This modularization of a complex system like the distribution grid enables functions to evolve incrementally as needs dictate, consistent with the overall architecture.[19,20] For example, the physical infrastructure of wires and transformers comprise part of the platform, but other components, such as sensing and operational communications, should also be considered as core in a modern grid."

The structure and use of open standards within a robust grid architecture are key to achieving an open and flexible grid.

As indicated in Commission Order 34281,[6] this type of platform will necessarily involve technologies with different life cycles as more digital and software components are integrated with legacy systems. Interfaces with customers and DER systems, such as inverters and aggregators, will likely be even more dynamic as these systems will have different lifecycles. The structure and use of open standards are key to achieving an open and flexible grid. This goal was discussed by several technology firms at our stakeholder workshop on May 10, 2017. This strategy combines the adoption of standardized protocols and interfaces with an architectural structure recommended by PNNL[21] to develop the high-level architecture that can create a more cost-effective cyber-physical grid that lowers the risk of technological obsolescence (Figure 3).

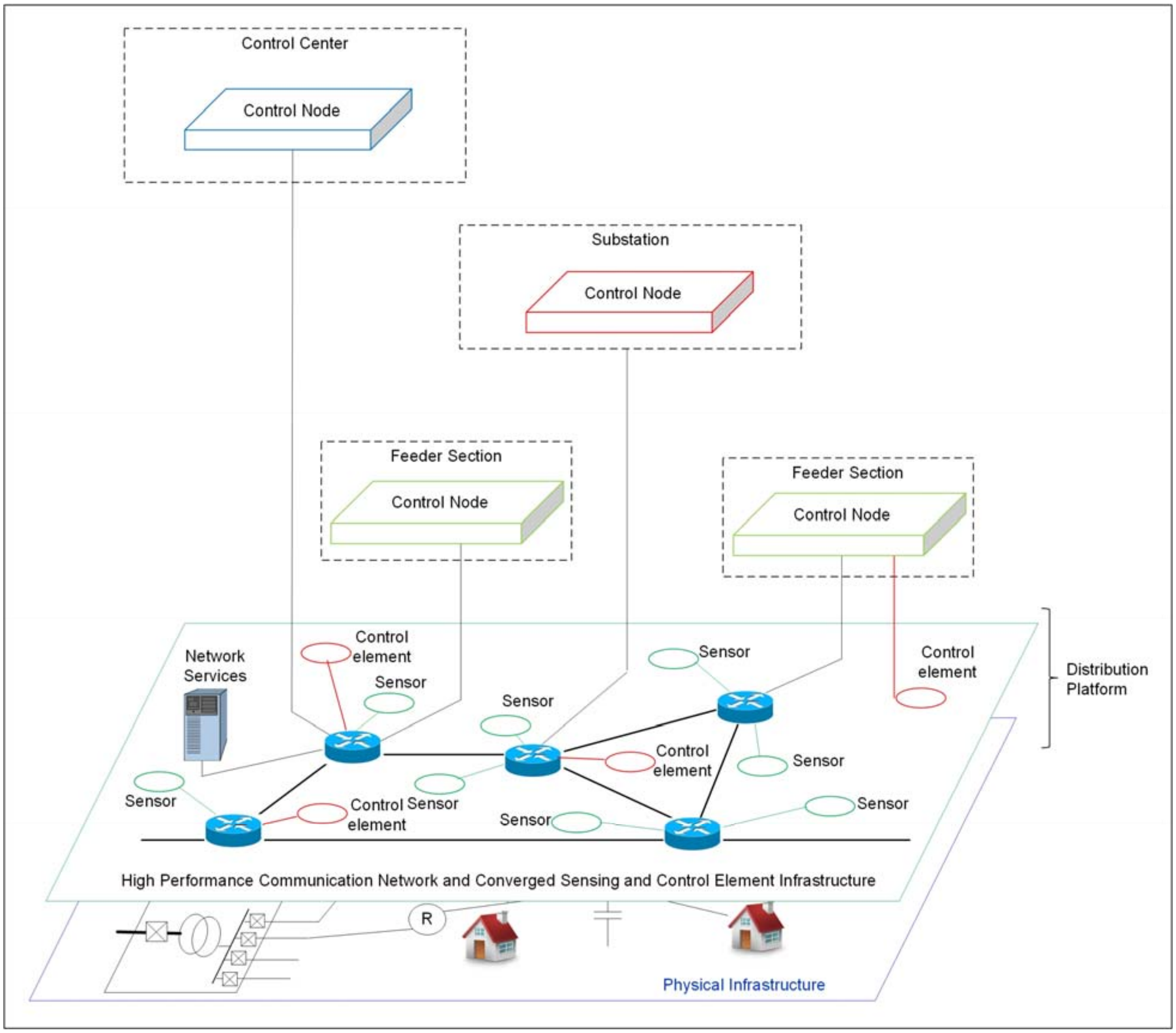
[18] DOE Next Generation Distribution System Platform (DSPx), Volume III http://doe-dspx.org/sample-page/dspx-volumes/

[19] C. Baldwin and C.J. Woodard, The Architecture of Platforms: A Unified View, Harvard Business School, 2008: http://www.hbs.edu/faculty/Publication%20Files/09-034_149607b7-2b95-4316-b4b6-1df66dd34e83.pdf

[20] Amrit Tiwana University of Georgia Benn Konsynski Emory University Ashley A. Bush Florida State University, Platform Evolution: Coevolution of Platform Architecture, Governance, and Environmental Dynamics, Information Systems Research, 2010: http://misrc.csom.umn.edu/workshops/2010/fall/ISR%20commentary%20forthcoming%202010.pdf

[21] PNNL Grid Architecture: http://gridarchitecture.pnnl.gov/

Figure 3 PNNL Architectural Structure Recommendation[21]



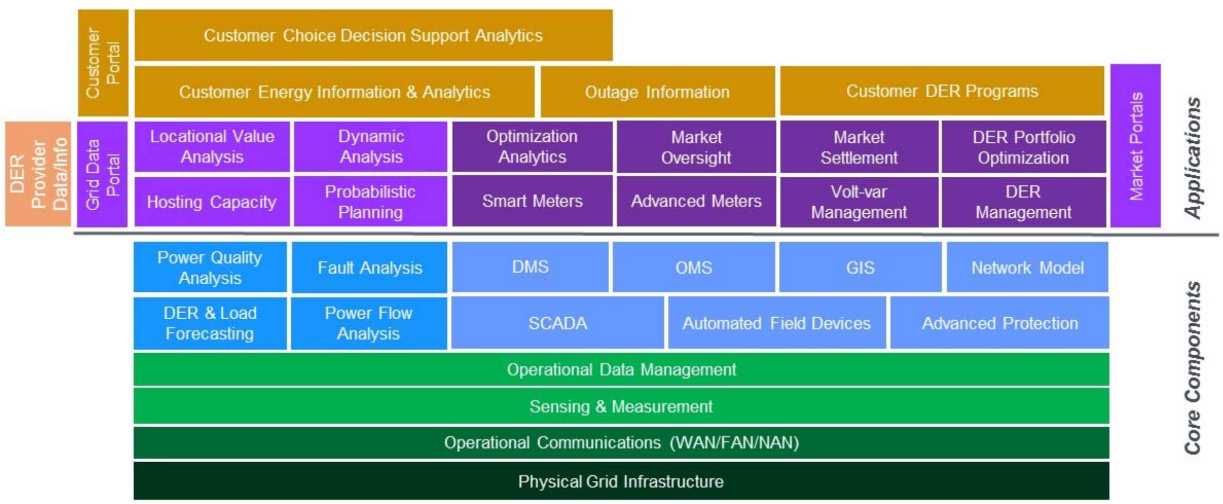
This layered architecture, enables the convergence of an integrated electric network with water, wastewater, street lighting, transportation systems, and other essential services to create more efficient and resilient infrastructure to enable the State's long-term economy and environmental policy objectives, as well as the objectives of our communities. Convergent "smart cities"[22] opportunities to minimize capital investment in infrastructure for synergistic societal benefits, such as smart street lights, can be fully evaluated in joint-planning efforts with cities or local communities. The Companies expect to continue to pursue these

[22] Smart Cities is defined as, ""A community of any size or significance, geographically separate or part of some larger urban unit, that leverages the convergence of electricity, water, telecommunications, transportation, social networks and the Internet of Things to a) improve aspects of its operations that are important to its economic vitality, safety, environmental footprint, quality of life or other significant factors; b) respond to the community's changing needs rapidly and efficiently; c) engage the community effectively; and d) collaborate with other communities." Adapted from Peter Williams, IBM http://meetingoftheminds.org/exactly-smart-city-16098

opportunities to fully utilize this modern grid platform for our customers' and the State's benefit.

The proposed platform will integrate physical infrastructure with advanced communications, sensing and measurement, and distribution automation, protection, and controls. Applications such as customer advanced metering will leverage this set of core platform technologies. Figure 4 from the DOE highlights many of the technologies the Companies are considering to transform the current grid to the grid we need. However, these technologies must be considered in the context of value for customers, and most can be deployed surgically when and where need as identified in the near term rather than as a system-wide deployment.

Figure 4 DOE DSPx Next Generation Distribution System Platform



Source: DOE, Modern Distribution Grid, Volume 3

3.3 PROPORTIONAL EVOLUTION

The many considerations raised in Commission Order 34281 highlight the need for a flexible, adaptive approach to grid modernization.[6] Such an approach must focus on achieving customer value, while not crowding out tomorrow's technological advances. This is why the Companies are proposing a *proportional* approach.

The Companies are cognizant of the issue of customer affordability. Therefore, the focus remains with those investments that yield the greatest near- and long-term customer value. The grid does not currently have the functionality and capacity to meet customer needs and accommodate additional DER adoption. Investment is needed across system operations, as described in Sections 5 and 6. Section 8 identifies a logical progression starting with today's

grid to develop a near-term grid modernization roadmap. This proportional "walk-jog-run"[23] approach for some grid functionality and related technologies has been used in California,[24] New York,[25] and elsewhere to manage grid modernization. Table 2 provides details on the current status and the proposed evolution in functionality for the Companies leveraging the framework developed by De Martini and Kristov.[26] This logical, stepwise approach to implementation should create the greatest benefit for customers.

Table 2 Modern Grid Functional Evolution

Distribution Functions	Walk	Jog	Run	Current Status
		1. Planning		
A. Load and DER Forecasting (short-term and long-term)	Develop multiple scenarios for load and DER growth. Align bottom-up distribution growth with top-down load forecasts.	Normalize bottom-up and top-down forecasts. Bottom-up forecasts include market insights and are used in planning.	Move from deterministic to probabilistic forecasting. Account for interaction of DERs.	Walk
B. DER Interconnection Studies and Procedures	Streamline the interconnection process, refine initial screening methods, and improve process transparency.	Process automation and development of Fast Track process, begin to apply hosting capacity results.	Full automation. Fast Track process based on hosting capacity analysis. Increased system data sharing needed.	Jog
C. DER Hosting Capacity Analysis	Hosting capacity used for indicative information for DER developers. DERs are evaluated individually and collectively through iteration.	Hosting capacity analysis is used in the planning process to assess potential upgrades to enable forecast of DER growth. DERs are considered as a portfolio but not optimized.	Hosting capacity analysis is used within the interconnection process. Simultaneous assessment of DER portfolios to further optimize hosting capacity.	Run

[23] More Than Smart, Planning for More Distributed Energy Resources on the Grid, 2016.

[24] The California IDER and DRP Working Groups: http://drpwg.org/

[25] New York Department of Public Service Case 14-M-0101, Proceeding on Reforming the Energy Vision - October 15, 2015 - Distributed System Implementation Plan (DSIP) Guidance: http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7bF3793BB0-0F01-4144-BA94-01D5CFAC6B63%7d

[26] De Martini and Kristov, Distribution Systems in a High Distributed Energy Resources Future: Planning, Market Design, Operation and Oversight, LBNL-DOE, 2015: https://emp.lbl.gov/sites/all/files/lbnl-1003797.pdf

Distribution Functions	Walk	Jog	Run	Current Status
D. DER Locational Value Analysis	System average distribution marginal costs identified along with specific bulk power system needs.	Identify incremental distribution upgrades, estimated avoided costs and non-wires alternative suitability as well as any locational bulk power system benefits.	Define methods for valuing societal benefits that may accrue at system level and locationally.	Walk
E. Integrated Resource, Transmission, and Distribution Planning	Align planning input assumptions.	Align resource, transmission, and distribution planning analyses and improve transparency, particularly at the distribution level.	Optimization across resource, transmission, and distribution systems. This is a transparent and collaborative process.	Run
		2. Operations		
A. Physical Coordination of DER Operation	Situational awareness of DER integrated with power system starting with DER asset information, including capabilities.	Optimization of DER aggregations for bulk power services. Coordination of use of DER with distribution operations. Access to participating DER availability and performance in real time. Implement smart inverter autonomous functionality.	Co-optimization of resources between bulk power & distribution systems. Coordination between DER providers, transmission, and distribution operations,	Not yet Walk
		3. Market		
A. Sourcing Energy, Ancillary, and Grid services	Use of DER/DR programs to provide peak load management. DER/DR pilots for more advanced grid services.	Use of DER/DR programs and aggregation for bulk power system services.	Use of DER/DR programs and aggregated DER/DR for bulk power system & distribution grid services.	Walk
B. Operational Bulk Power & Distribution Grid Services Animation	Initial DER program design and participation rules without aggregation.	Set up program rules for use of aggregated DERs including protocols for curtailments due to bulk power system constraints. Sourcing through tariffs, programs, and competitive procurements.	Define distribution grid service rules & protocols for dispatch priorities for potential DER participation to address both bulk power system and distribution constraints.	Walk

Distribution Functions	Walk	Jog	Run	Current Status
C. Operation and Settlement for DER Services	Application of program pricing and M&V requirements	Define control, measurement and telemetry requirements and locations for aggregated DER	Reconcile scheduled vs real-time dispatch, any curtailments and DER aggregated performance for bulk power system and distribution services settlement	Not yet Walk
D. Program Facilitation Services	Customer data available	Bulk power & distribution system data information and DER provider data exchange	Bulk power and distribution operational information and sourcing platforms	Not yet Walk

Also, leveraging investments in a common core platform (even incrementally) will enable the ability to deploy tailored bundles of technologies in the field to address specific needs proportionally. However, in some instances, foundational investments, in particular software systems (e.g., distribution management system [DMS], demand response management system [DRMS], and distributed energy resource management system [DERMS]), are necessary to initiate related services or programs.[27]

The Companies believe that this strategic approach enables the implementation of upgrades consistent with the pace of customer needs and the effects of policies. As described in this strategy's roadmap, the deployment involves multiyear (perhaps a decade or more) efforts for solutions and technologies to be deployed. This approach, while inherently flexible, cannot completely eliminate every risk related to technology obsolesce due to rapid innovation. However, given the current demand for DER and insufficient grid capacity, grid modernization cannot wait.

This proportional approach enables us to implement upgrades consistent with the pace of customer value.

The Companies concur with the Commission that an effective architecture along with standards-based interoperability are essential strategic elements. The Companies also believe this strategy and any implementation plans should be linked to a comprehensive grid planning process and methods that are based on clearly understood and transparent assumptions of customer needs, policy objectives, forecasts of renewable and distributed energy resources, and load.

[27] The Companies recognize that there will be a likely convergence in the DRMS and DERMS system functionalities, see, HPUC Docket No. 2015-0411.

4 Integrated Grid Planning & Framework for Cost-Effectiveness

The Companies recognize the need for continuing grid evolution to affordably meet customers' needs and Hawai`i's RPS goal. Charting the path from the present toward the future electric infrastructure in Hawai`i must include flexible course of action to adapt to customer needs, changing circumstances, and rapidly evolving technologies that have been so evident over the past several years.

Creating a modern grid will require an ongoing integrated grid planning process that integrates bulk system resource planning with transmission and distribution planning to assess total resource net benefits.

4.1 INTEGRATED GRID PLANNING WITH STAKEHOLDER ENGAGEMENT

The Companies are proposing that this integrated grid-planning process should be conducted every two years using the analysis framework and methods employed in the Companies' recent PSIP, combined with additional information regarding incremental grid infrastructure costs that would enable new types and quantities of DER. The PSIP filing has been recognized as one of the most transparent descriptions of the various planning analysis and methods filed by a utility to-date.[28] However, there are several aspects that can be improved related to stakeholder engagement and the determination of the necessary grid investments going forward.

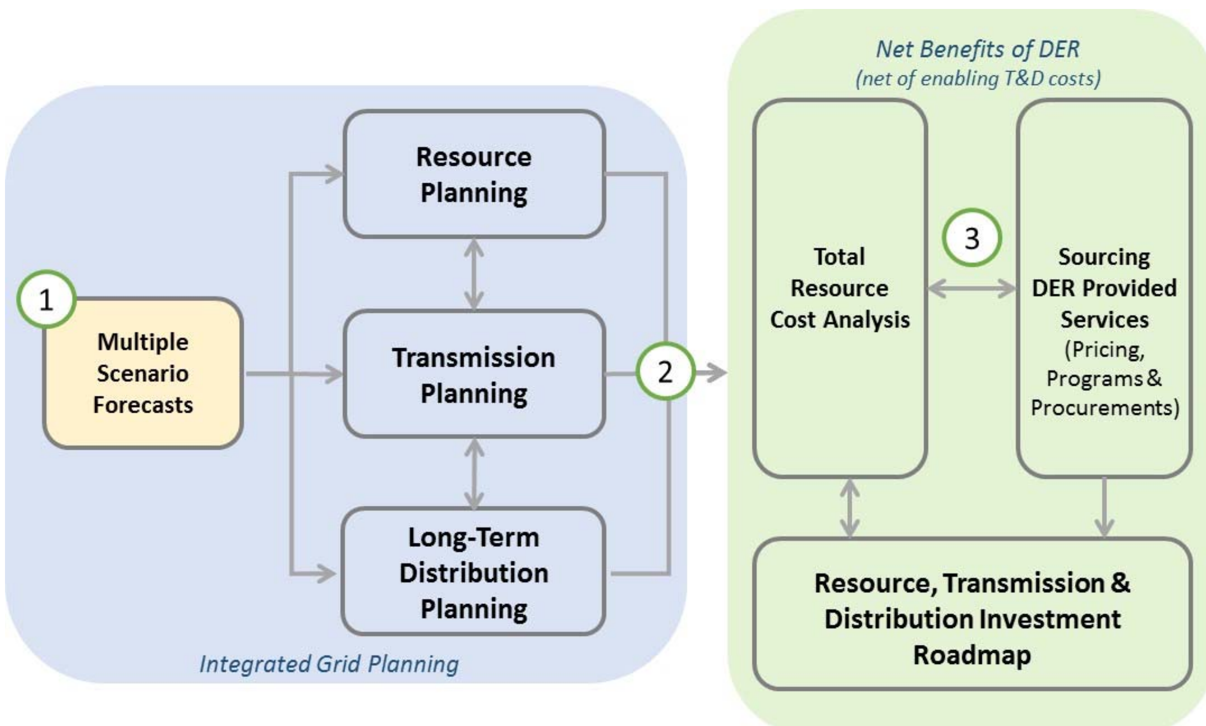
This framework has a number of benefits. Primarily, stakeholders will have the opportunity to provide input in the planning assumptions and feedback on the results. For the Companies, the framework facilitates the incorporation of outside perspectives throughout the planning cycle, especially in the development of future scenarios and their implications. Furthermore, it has the potential to streamline the planning process, as important stakeholder inputs can be discussed and considered at the appropriate juncture, rather than being deferred to a formal Commission proceeding. Integrated grid planning is being discussed in several states; however, this is the first proposed implementation of the concept.

[28] Feedback received from participants at May 10, 2017 Grid Modernization Workshop

4.1.1 Integrated Grid Planning

A possible framework that encapsulates the integrated grid planning needs and enhanced stakeholder engagement is illustrated in Figure 5. This process that the Companies are proposing is called "C^{3}GP," for, Comprehensive, Customer-Focused, and Cooperative Grid Planning. In concept, the process would evaluate a 5- to 10-year planning horizon. A planning cycle would be completed every two years and should, in an integrated fashion, consider the needs at all levels of the system: customer, bulk power resources, transmission, and distribution. The process would engage customers and stakeholders at key junctures in the integrated resource, transmission and distribution planning effort.

Figure 5 Proposed C^{3}GP Integrated Grid Planning Process



(Note: Numbers in Figure 5 relate to the points of stakeholder engagement described in the next section.)

In an ongoing integrated grid planning process, enhancements to distribution planning will be needed, not unlike those already done by the Companies for resource and transmission planning in the recent PSIP. This is described generically in the DOE's Integrated Distribution Planning paper.[29] In such a planning process, grid modernization investments are identified to address one or more of four categories:

A. Improved reliability, safety and/or operational efficiency (standards & compliance)

[29] ICF, Integrated Distribution Planning, DOE, 2016: https://energy.gov/sites/prod/files/2016/09/f33/DOE%20MPUC%20Integrated%20Distribution%20Planning%208312016.pdf

B. Integrated DER adopted by customers or RPS goals (policy compliance)
C. Utilized customer DER or merchant DER to provide services to the system (net benefits)
D. Investments to support a customer's or group of customers' unique needs (self-supporting)

Grid investments in category A include those advanced technologies that overlay the physical poles and wires infrastructure to transform a largely analog grid into a modern digital grid. These investments, which include grid sensing and measurement, telecommunications and automation/controls technologies that, when combined with the other elements of the physical infrastructure, form the core platform described in Section 3.2.2. Additional investments in this category are required to meet reliability and service quality standards. These investments are identified in the annual distribution planning process and are necessary prerequisites for additional technology applications identified for categories B and C (discussed below).

Modern grid investments in customer- and/or merchant-adopted DER (category B) are driven by customer choices and often shaped by policies such as rate design, mandates and incentives. These potential investments should be identified in an integrated grid-planning process. Some of these investments may not be necessary since diversity of DER adoption may mitigate the impact on the system. A richer understanding of what investments are necessary is what makes forecast assumptions and scenarios vital to the ongoing planning discussion with the Commission and stakeholders. However, for legacy DER, it is important to recognize the capability gaps that exist and to address the service quality and reliability issues that the Companies currently face. Investments needed to address the service quality issues are related to voltage violations that arose from the dramatic growth in customer DER adoption over the past five years.

The modern grid investments in category C are necessary to enable DER aggregators to provide services to us to help cost-effectively manage the power system. Today, supplied services are focused on the bulk power system. However, assuming that the current DER programs prove effective, we anticipate sourcing DER services for distribution needs as well. The Companies are also closely following the pilots in California, New York, and elsewhere to gain insights on emerging leading practices.[30] Hawai`i, along with these other states, is at the leading edge of utilizing behind-the-meter DER as system and grid resources. The Companies expect to learn much over the next five years that will shape the ongoing grid modernization strategy.

[30] California Independent System Operator - Opportunities for distributed energy resources: http://www.caiso.com/informed/Pages/CleanGrid/default.aspx; New York Independent System Operator - Distributed Energy Resources Roadmap for New York's Wholesale Electricity Markets: http://www.nyiso.com/public/webdocs/markets_operations/market_data/demand_response/Distributed_Energy_Resources/Distributed_Energy_Resources_Roadmap.pdf

Investments in category D are driven by the unique needs and requests of a customer or specific group of customers that are at the customer's option and will be paid for by that customer alone.

4.1.2 Stakeholder Engagement

As identified in Figure 5, there are three key points of stakeholder engagement. First, stakeholder engagement in the development of forecast assumptions and scenarios developed for use in the planning process is essential. The Companies understand that without the buy-in of stakeholders, the planning results may not be accepted.

Second, the engineering results that identify incremental grid needs should be reviewed with stakeholders. This "grid needs" discussion has been identified by stakeholders in other states as a key decision point. These discussions would consider whether the diversity of customer adoption of DER may offset the need to incrementally expend costs to invest in the grid or source DER services. This may also inform rate design and other related policy decisions that influence customer decisions and the affordability of proposed solutions. The opportunity to understand the impact of policy decisions and adjust as needed is seen as a critical application of this type of integrated grid planning process to address affordability. This approach has been advocated by consumer advocates, the Natural Resource Defense Council, the Environmental Defense Fund, and other stakeholders in Hawai`i and other states.[31]

The Companies believe that using a smaller working group of stakeholders to provide preliminary review/feedback before undertaking a broader review is an effective approach. This is an approach that has been used successfully in system planning on the mainland,[32] as well as increasingly for integrated distribution planning. For example, a California working group focuses on the forecast assumptions and scenarios that are subsequently reviewed by a wider set of stakeholders.[33]

Third, when grid needs are identified there needs to be a simple, transparent process to conduct a comparative evaluation of wires and non-wires alternatives or traditional versus technology-driven alternatives. The evaluation of alternatives will involve proprietary and confidential information to ensure commercially competitive solutions are proposed. Therefore, a select group of *non-market participants* should be convened. For example, in California, a group comprised of regulatory staff, consumer advocate, and a few independent advocates that have signed non-disclosure agreements review the results of RPS procurements.

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[31] California PUC Rulemaking 14-08-013 - Response of Environmental Defense Fund to Utilities' Applications for Approval of Distribution Resources Plans: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M154/K305/154305338.PDF

[32] Midcontinent Independent System Operator (MISO) - Transmission Expansion Planning (MTEP): https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/TransmissionExpansionPlanning.aspx

[33] The California IDER and DRP Working Groups: http://drpwg.org/

Stakeholder participation in the process should be formalized with qualified representatives of stakeholder groups (with subject matter knowledge) engaged at a working level on specific topics and the broader stakeholder groups engaged to review the working group outcomes. This approach to integrated grid planning and stakeholder engagement is consistent with best practices in transmission and emerging for distribution as part of a holistic system analysis. For example, FERC directed that similar processes be implemented by the mainland RTOs to facilitate the timely and meaningful input and participation of customers in the development of transmission plans and that "customers must be included at the early stages of the development of the transmission plan and not merely given an opportunity to comment on transmission plans that were developed in the first instance without their input."[34] Additionally, topical and ad hoc stakeholder engagements would be conducted to provide further information and insight.

4.1.3 Planning, System & DER Data

The integrated grid-planning process described in this section is dependent on data from generating resources and grid operations. The process itself produces information that is useful to a number of stakeholders in addition to the Companies' business processes. California's Distributed Resource Plan and New York's Reforming the Energy Vision both identified system and DER related data as essential to both grid operators and DER providers. As noted by More Than Smart[35]:

> "Robust data analysis and advanced informational capabilities present an opportunity to optimize grid operations and investments as well as where distributed resources provide the most value. However, system and DER data exchange will also require navigating challenging questions about privacy, security, and market design."

In developing this strategy, the Companies adapted the More Than Smart data matrix in Appendix E to highlight the current and proposed planning and system data availability and the data needed from distributed resources to plan and operate the system. The DER data noted should be made available under interconnection and/or market participation rules. This is no different than the information that independent power producers are required to provide for bulk power system planning and operations in Hawai`i and on the mainland. We recommend the Commission consider a holistic discussion on data sharing for planning and operations as opposed to discussions in multiple proceedings.

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[34] From http://www.transmissionhub.com/articles/2016/09/ferc-establishes-proceeding-to-determine-whether-pjm-transmission-owners-are-complying-with-order-890-obligations.html

[35] A. Shumavon, P. De Martini and L. Wang, Data and the Electricity Grid, More Than Smart, 2016: http://morethansmart.org/wp-content/uploads/2016/10/Data-and-the-Electricity-Grid-MTS-System-Data-Paper.pdf

4.1.4 Grid Services

The output from the planning process is an identification of resource and grid needs that may be met by more traditional utility "wires" or a "non-wires" solution, such as a DER service. Currently the Companies are proposing demand response programs for DER services for bulk power system and anticipate there may be opportunities for distribution services in the future.[36] However, as noted in California[37], for DERs to successfully provide grid services, they must meet the same technical and operating standards as the rest of the system such that when DERs are interconnected, they do not impact the safety and reliability of the grid. In addition, DERs providing services must also operate in a manner that aligns with the local transmission and distribution area's electrical loading attributes to ensure safe and reliable distribution service.

The California utilities and stakeholder group developed and agreed upon a common set of four principles for articulation of grid services that the Company proposes to use. The four principles are as follows:[38]

- Location of where distribution service is provided
- Timing of when distribution service is provided
- Level of DER service provided
- DER availability and assurance of ability to provide

Additionally, stakeholder discussions in California and New York[39], on the use of DER as non-wires alternatives have recognized that bulk power system services may offer the greatest opportunities while distribution opportunities may be more limited.[40,41] This is likely the case in the Companies' system, as there is little load growth creating a need for incremental substation or distribution capacity. For example, the ability for DER to defer capital investment is limited on feeders where distributed photovoltaic generation (DG-PV) hosting capacity is already exceeded.

[36] See HPUC Docket No. 2015-0412, Application of Hawaiian Electric Companies for Approval of Demand Response Program Portfolio Tariff Structure.

[37] California Competitive Solicitation Working Group, Distribution Services, Attributes and Performance Requirements, Draft July 11, 2016 http://drpwg.org/wp-content/uploads/2016/07/CSFWG-Sub-Team-2a.-Summary-Conclusions-and-Recommendations.docx

[38] The California IDER and DRP Working Groups - Distribution Services, Attributes and Performance Requirements Draft July 11, 2016: https://view.officeapps.live.com/op/view.aspx?src=http://drpwg.org/wp-content/uploads/2016/07/CSFWG-Sub-Team-1.-Summary-Conclusions-and-Recommendations.docx

[39] Joint Utilities of New York Stakeholder Engagement, Summary Presentation Deck on NWA Suitability Meetings, July 2016 http://jointutilitiesofny.org/wp-content/uploads/2016/06/Distribution-System-Planning-EG-on-NWA-Suitability-Final.pptx

[40] Tierney, S., The Value of "DER" to "D", The Analysis Group, March 2016 http://www.analysisgroup.com/uploadedfiles/content/news_and_events/news/value_of_der_to%20_d.pdf

[41] De Martini, P., et al., Evolving Distribution Operational Markets, Caltech-ICF, 2016 http://resnick.caltech.edu/docs/EDOM.pdf

4.2 COST-EFFECTIVENESS FRAMEWORK

Ensuring customer affordability requires a new framework for evaluating benefits and costs of resources and those enabling grid investments.

As described above, to develop a modern grid that is affordable for customers, the Companies need to make investments that are cost-effective, targeted, and time-phased. In many ways, this is the biggest challenge for our modernization strategy: building a delivery system that can operate reliably with 100% renewable energy by 2045, at a reasonable cost with acceptable adjustments to electricity rates. Clearly, we cannot get there with traditional planning methods alone. Because we will be deploying new grid technologies that enable a mix of large-scale and distributed renewable resources, we need to develop a new framework for evaluating benefits and costs of resources and those incremental enabling grid investments. Additionally, several grid modernization technologies enable multiple benefits and future flexibility. This is particularly true for core platform technologies, which are discussed in Section 7. The need for a new holistic evaluation framework has been recognized in other jurisdictions that are addressing grid modernization.[42] The framework, methodology and several examples are described in more detail in Appendix C of this filing.

As summarized in Table 3, the framework the Companies are developing incorporates as many as four distinct benefit/cost methodologies, depending on the type of investment being evaluated.

Table 3 Expenditure Categories and Evaluation Methodologies

Expenditure Purpose Category	Methodology
Standards and Safety Compliance Grid expenditures required to ensure reliable operations or comply with service quality and safety standards	Lowest reasonable cost (similar to least-cost, best-fit used in other jurisdictions)
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

[42] See for example, CA PUC, Rulemaking 14-08-013, Assigned Commissioner's Ruling on Guidance for Public Utilities Code Section 769 – Distribution Resource Planning, Feb. 2, 2015: http://www.cpuc.ca.gov/General.aspx?id=5071; NY PSC, Case 14-M-0101, Order Adopting Distributed System Implementation Plan Guidance, April 20, 2016 http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=14-M-0101&submit=Search:

Expenditure Purpose Category	Methodology
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
Self-Supporting Expenditures incurred for a specific customer (e.g., interconnection), with costs directly assigned to those specific customers.	The category is for projects that do not shift a cost burden to non-participants. This category does not require benefit-cost justification.

4.2.1 Lowest Reasonable Cost Method

The Lowest Reasonable Cost Method is the most practical approach to evaluating investments to build the core modern distribution platform. The Companies expect to use reasonableness (or "best-fit") assessments to narrow the range of options for certain core platform technologies (e.g., sensing and measurement, communications, and controls/automation) consistent with DOE's platform framework.[18] This method is also used for other expenditures in 1) the Standards and Safety Compliance category, and 2) the Policy Compliance category. In the Lowest Reasonable Cost method we first evaluate an asset in terms of how well it supports the standards, safety, or policy need(s). To the extent an asset supports the engineering need, it "fits." The second step is to evaluate the cost of the asset. In most cases, this will occur through a competitive procurement process. While cost is a primary evaluation metric for this review, other attributes of the assets are considered, such as the ability to enable future functionality. Therefore, the selected projects may not be strictly the lowest cost options. Investments that are primarily related to providing safe and reliable service, such as aging infrastructure replacement will continue to be considered as part of ongoing capital investment planning and program evaluation.

4.2.2 Net Benefits Analysis

For investments that are not required for compliance purposes and are not self-supporting projects, we apply the Total Resource Cost (TRC) framework. This is done as part of the ongoing integrated grid-planning process that evaluates the net benefits of resources and required enabling grid investments. In this case, the benefits associated with the resources and the grid investments are offsetting costs to yield net benefit for customers.

As part of the ongoing integrated grid-planning process, the Companies will identify grid investments that enable renewable resource integration and utilization that may lower net costs for customers. Those resource benefits and related enabling grid investments would be evaluated using this Net Benefits framework. This framework creates a consistent integrated approach to assess the benefits of a combination of large-scale and distributed resources and

the related transmission and distribution-level costs. In this way, the potential synergies and economies between grid investments and various distributed energy resources are captured.

Table 4 shows the benefit and cost components included in the Companies' TRC framework (indicated by an "X"). The Companies' benefit-cost analysis evaluates the benefits of large-scale and distributed resources against the costs of incremental enabling grid modernization investments or operational services sourced from third-party DER. It is important to note that in some cases it may be more cost-effective for the Companies to source needed distribution grid services from other DER (e.g., demand response or storage) to enable the benefits of customer adoption of DER (e.g., DG-PV). These costs offset the benefits of the proposed DER to yield net benefits to all customers. The Companies' TRC framework is consistent with EPRI's Integrated Benefit Cost framework, with the exception that the EPRI framework includes societal impacts like the health or environmental damages of greenhouse gas (GHG) emissions.[43] While such non-energy benefits are often mentioned, especially with respect to DER that could be further enabled by grid modernization projects, those values are difficult to estimate and are not included at this time.

Table 4 Benefits and Costs in TRC Framework

Costs and Benefits	Total Resource Cost (TRC)
Benefits	
Bulk System Impacts from RESOLVE Model	
Generation Capacity	X
Energy	X
Transmission Capacity	X
Reduced Transmission Losses	X
Avoided Ancillary Services	X
T&D System Benefits	
Avoided Subtransmission Capacity	X
Avoided Distribution Capacity	X
Reduced O&M	X
Avoided Distribution Losses	X
Avoided Restoration Costs	X
Other Operational Benefits	
Reduced revenue cycle service costs	X
Reduced restoration and staging costs	X
Customer Benefits	
Reduced Customer Outage Costs	X
Increased customer choice	

[43] EPRI Integrated Grid Online Community, Phase II: The Benefit-Cost Framework - http://integratedgrid.com/phase-ii-the-benefit-cost-framework/

Costs and Benefits	Total Resource Cost (TRC)
External Benefits	
Avoided Emissions	X
Avoided Water Impacts	
Avoided Land Impacts	
Non-Energy Benefits	
Costs	
Incremental T&D Costs and/or DER provided Distribution Grid Services	X
Incremental Program and Admin Costs	X
Increased Ancillary Service Costs	X
Participant Costs	
Lost Utility Revenue	
Non-Energy Costs	

In the near term, the Companies are focusing the grid modernization work on foundational core investments and those investments necessary to resolve the service quality issues associated with the unprecedented DER growth over the past five years. These investments are required to provide safe and reliable service, support continued customer choices and growth of DER, and accommodate state and Commission policies.

Going forward, the Companies will look to identify and assess anticipated and large grid modernization investments in relation to the benefits of the distributed resources forecast as part of the overall resource mix of renewables toward Hawai`i's 100% goal. This will integrate both DER and incremental grid modernization costs into the overall prospective integrated grid planning process. For example, if customer DER adoption forecasts do not align with integrated planning process assumptions, resource plan adjustments may be required. These costs, in some cases, will not only support the short-term need but also future customer growth. Based on just the benefits of the immediate customers' distributed resource, the cost of the grid investment may not appear to yield net benefits for all customers. However, the additional enabled benefits from future distributed resource growth will justify the investment. Such grid investment or sourcing of DER services would be identified and a discussion of non-quantified benefits provided to promote transparency.

4.2.3 Self-Supporting Projects

Self-supporting investments would primarily be paid for by participating customers. Any utility contribution or incentive would be limited to the net benefits that would be expected to accrue to utility non-participants. In this way, any self-supporting program would be designed to prevent cost-shifting from participants to non-participants. These programs would also be based on customer choice with an opt-in approach, so the participants would make their own decisions regarding participation.

The joint conditions of 1) no cost-shift to non-participants and 2) participants choosing to participate obviates the need for a TRC cost-effectiveness test. Depending on the utility

contribution or incentive, net benefits would be calculated for program design purposes. However, a self-supporting project would not be required to pass a TRC test.

4.2.4 Margin Neutral Rates and Summary

The evaluation framework used in this proposal assumes that proposed expenditures that have estimated positive net benefits also reduce costs for all customers. This situation is only true if a DER participant's bill reduction is not greater than the costs the utility avoids via the grid services provided. If DER participants are paid for their services via a procurement process that is capped at the utility, these customers should be served on "margin" neutral rates that separate fixed from variable costs clearly in their rate components. Several examples of margin neutral rates are provided in Appendix C to this report.

The fixed costs typically include the basic costs to interconnect and serve a customer (customer costs), and the fixed costs of building and reliably operating the grid (grid access fees). Variable costs include the costs to produce energy as well as the costs of providing ancillary services required to support the grid. The Companies have defined a set of four grid services made available to customers through proposed schedule and new rate riders in Docket No. 2015-0412.

Although the Companies are not asking to modify rates as part of the grid modernization strategy, cost recovery of grid modernization investments is closely intertwined with both the DER and DR proceedings via retail rate design.[44] In those proceedings, DER compensation levels are being determined. For example, pursuant to the procedural schedule in the DER proceeding,[45] Market Track issues are to be briefed by August 2018, with Final Statements of Position due in September 2018. In addition, the Interim Residential Time-of-Use Service ("TOU-RI") annual report is due no later than January 31, 2018. As such, the Companies will examine, collaborate with other stakeholders, and, as appropriate, propose new rate designs in the concurrent DER and DR proceedings.

In summary, the analytic framework the Companies are developing as part of the modernization strategy applies four discrete methods, each calibrated to a particular type of asset/cost, as identified in the integrated grid planning described in Section 4.1.1.

1) The **Lowest Reasonable Cost** is being used to evaluate components of the core platform that are necessary to comply with either a standard or to maintain safety. It takes account of new functional requirements of the grid and the risk associated with new grid technologies. The Lowest Reasonable Cost Method is also being used to evaluate expenditures that are necessary to comply with state or Commission policies,

[44] HPUC Docket No. 2014-0192, Distributed Energy Resources Policies and Docket No. 2015-0412, Demand Response Portfolio Structure.

[45] HPUC Order No. 34206, "Establishing Statement of Issues and Procedural Schedule for Phase 2", Docket No. 2014-0192, dated December 9, 2016.

such as achieving 100% renewable energy and accommodate increasing numbers of DER.

2) A **TRC Framework** is applied to modular additions that will improve operational efficiency and/or otherwise lower net costs for customers. The TRC framework will also continue to be applied in the PSIP to promote synergies and economies between grid investments and various distributed energy resources.
3) DER participants are assumed to be served on "margin neutral" rates for their potential to lower costs for ratepayers.
4) A cost test is not required for **self-supporting** projects, although net benefits would need to be estimated as part of designing any utility incentives or contributions.

Taken together, these methods comprise an analytic framework that places the project review methodology in the context of the purpose of the project. This promotes transparency and will guide the Companies to investments that meet the current and future needs of the grid and their customers.

5 Starting Point: Current Status of the Electric Grids

This grid modernization strategy starts by building upon the grid modernization investments that have already been made and leveraging the experience gained by integrating DER.

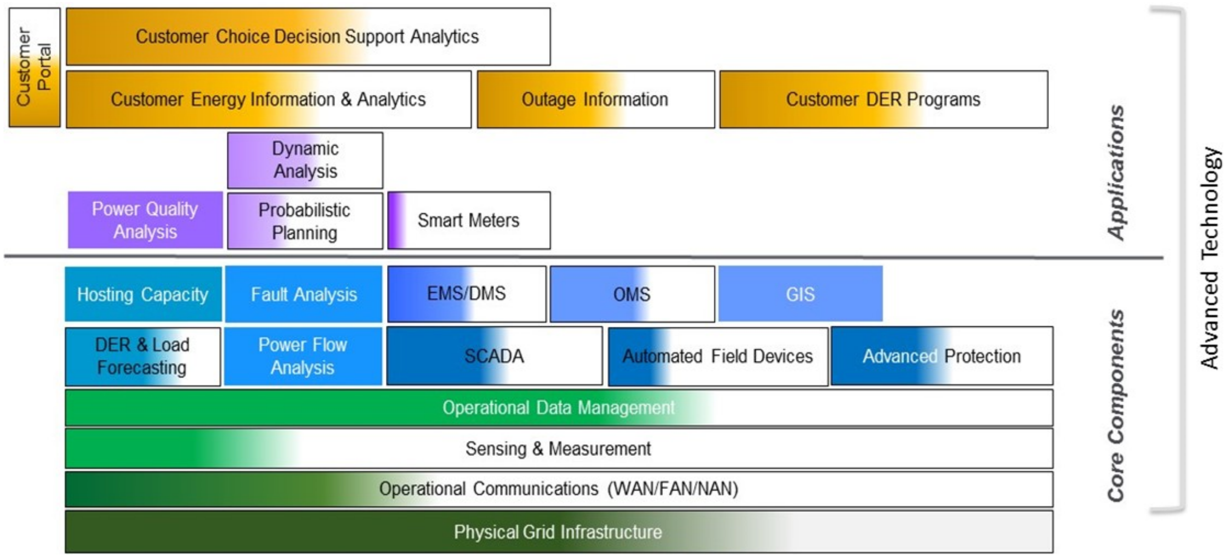
This section provides a brief overview of the current status of the modernization of the grid and technical challenges that are impacting customer service quality and overall system reliability. These challenges underscore the urgency of a comprehensive, coherent, and actionable grid modernization strategy. Appendix D contains further details the current status of the Companies' grids.

5.1 CURRENT STATUS OF GRID MODERNIZATION

The Companies have been investing in customer-facing and advanced grid technologies throughout the system over the past decade. This is represented conceptually in Figure 6 utilizing the platform framework adapted from DOE.[18] The technologies identified and shading represent the relative progress toward modernization envisioned in this strategy. Brief overviews of these technologies are provided in the following subsections.

Grid Modernization is an evolution that is underway. There is more to be done, however, and technology innovations will help us address these needs.

Figure 6 Current Status of Companies' Customer Facing and Advanced Grid Technologies



5.1.1 Customer-Facing Technologies

The Companies are currently providing customer energy information and analytics as well as customer choice decision support tools to help customers stay informed during power outages and make informed decisions regarding their electricity usage and major purchases, such as PV systems and EVs. Additional information on these programs is included in Section 6.2.

Also, customer information and analytics were implemented as part of the Initial Phase Smart Grid demonstration project on O`ahu, which included 5,000 smart meter installations in various geographic and demographic terrains.[46] During this initial phase, the Companies evaluated their internal processes to gain valuable insight as to where and how to improve the overall customer experience by extending customer outreach and refining educational materials. Lessons learned from this second-generation smart meter demonstration are discussed in Section 6.1.1.

Customer DER programs include support for customer DG-PV interconnection[47] and the pending DR program applications.[48] Although the Companies do have a customer self-supply (CSS) non-export DG-PV program available, there are many customers that would like to install DG-PV systems without energy storage but are unfortunately connected to distribution circuits that have already reached their hosting capacity limit. In some instances, the Companies have upgraded the grid infrastructure to increase hosting capacity to enable

[46] Hawaiian Electric completes first phase of smart grid installation, 9/24/2014: https://www.hawaiianelectric.com/hawaiian-electric-completes-first-phase-of-smart-grid-installation

[47] Hawaiian Electric Companies - Integration Tools and Resources: https://www.hawaiianelectric.com/clean-energy-hawaii/integration-tools-and-resources/integrated-interconnection-queue

[48] H PUC Docket No. 2015-0411 and Docket No. 2015-0412

additional customer DG-PV interconnection.[49] However, this approach is not scalable to meet customer needs. Therefore, Section 7 of this strategy explores alternatives to help mitigate distribution issues like voltage regulation when hosting capacity is exceeded. Section 6.4 includes information on the DR programs as well as customer-sited energy storage. Customer DER programs include support for customer DG-PV interconnection[50] and the pending DR program applications.[51]

5.1.2 Grid-Facing Technologies

Just as it does not make sense to start remodeling a house by installing the latest smart home technology while the structure and foundation are falling apart, it does not make sense for the Companies to add advanced grid technologies to a grid with a deteriorated foundation. The Companies have an ongoing infrastructure replacement program for the core physical infrastructure that is the foundation for any modernization effort. The challenge for any utility today is that the grid, particularly with regard to distribution, is at various states of capability. It is not cost-effective to address all issues at once, so prioritization is employed to focus on the greatest need and the highest customer value. In this context, the current state of the Companies’ grid is summarized below.

Physical Grid Infrastructure

The Companies have installed transmission and distribution (T&D) infrastructure over many decades to support electric growth - much of it from 30 to 60 years ago during a period of economic growth following statehood. Figure 7, Figure 8, and Figure 9 below illustrate the age demographic of the Companies’ physical grid assets (original cost adjusted for inflation).

Over time, T&D infrastructure deteriorates or is weakened due to a number of factors, including normal wear and tear, mechanical stress, dielectric breakdown, weather, corrosion, rot, contamination, or animal/human damage.[52] This deterioration leads to failures that cause power outages. The Companies have an ongoing infrastructure replacement program to address these issues. Replacement of aging utility infrastructure is generally more expensive in real (inflation adjusted) dollars than the original installations. This is primarily due to the increased scope and complexity of replacement projects. For example, directly burying distribution cables in green-field residential developments was a common industry practice in

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[49] The companies have executed circuit upgrades to facilitate DG-PV interconnections, See, Docket No. 2014-0183, PSIP Update Report: December 2016 at N-51.

[50] Hawaiian Electric Companies - Integration Tools and Resources: https://www.hawaiianelectric.com/clean-energy-hawaii/integration-tools-and-resources/integrated-interconnection-queue

[51] HPUC Docket No. 2015-0411 and HPUC Docket No. 2015-0412

[52] This is easily visualized when considering aging wood pole infrastructure that may be rotted due to weathering or termite infestations. The wooden pole infrastructure is comprised of both new and aging poles that may need to be replaced or upgraded to ensure reliability and to protect technology investments.

the 1960s and 1970s due to lower installation costs and long cable life expectancy. However, replacement of these cables that are now failing at increasing rates involves much more.[53]

The Companies' aging grid infrastructure issues and on-going replacement program are consistent with the industry, which built much of the existing distribution in the post-WWII period. This asset replacement program improves safety and customer reliability and increases the capacity for DER integration. Infrastructure replacement coincides with the need to modernize, and opportunities to coordinate installation of advanced grid technology in the field will be pursued.

Figure 7 Hawaiian Electric In-Service T&D Infrastructure Assets (2016$)[54]

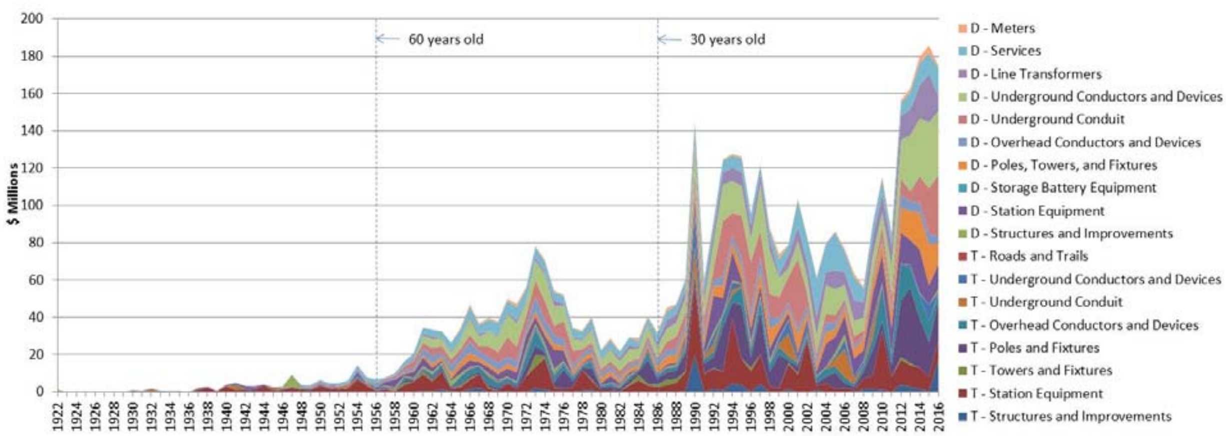
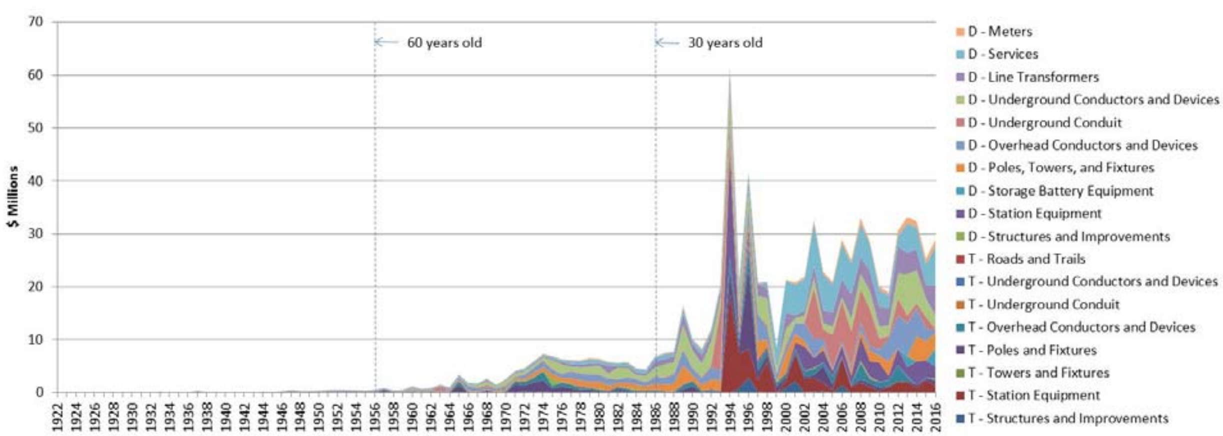


Figure 8: Maui Electric In-Service T&D Infrastructure Assets (2016$)[55]

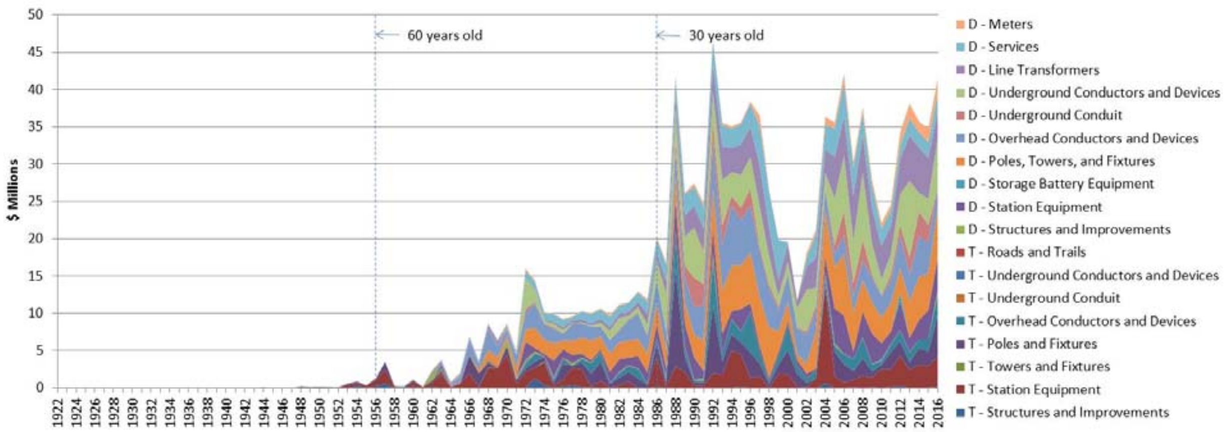


[53] The current process for replacing buried distribution cables includes neighborhood notification/communications, location and avoidance of other buried utilities, traffic control, circuit switching/reconfiguration to minimize existing customer service interruptions, excavation of existing roads, sidewalks, driveways, and landscaping, installation of concrete covered/encased conduits (current standard for cable protection and ease of replacement), and restoration of all excavated surfaces/landscaping.

[54] Hawaiian Electric Companies' plant accounting as of December 31, 2016.

[55] Maui Electric plant accounting as of December 31, 2016.

Figure 9: Hawai`i Electric Light In-Service T&D Infrastructure Assets (2016$)[56]



Grid-Facing Technologies

Modern grids are defined by information that is dependent on operational communications networks, sensing and measurement, operational controls and analytics, and field automation. These technologies form the foundational cyber-physical grid infrastructure. Furthermore, planning models and tools are required to properly assess the changes underway. Applications that leverage this core platform include advanced metering and enhanced planning tools, among others. Table 5 summarizes the current state of grid technology deployment at each of the operating companies. It is advanced technologies that will lead to more efficient grid operations and utilization of DER. The absence of continued progress on the Companies modernization efforts to date will result in unsolved operational challenges as described in Section 5.2.

[56] Hawai`i Electric Light plant accounting as of December 31, 2016.

Table 5 Hawaiian Electric Companies' Progress Toward Grid Modernization

TECHNOLOGY	HECO	HELCO	MECO
FOUNDATIONAL			
Operational Communications			
Wide Area Networks	◑	◑	◑
Field Area Networks	○	○	○
Neighborhood Area Networks	○	○	○
Sensing & Measurement			
Secondary Voltage Monitoring	◔	◔	◔
Faulted Circuit Indicators	◕	◕	◕
Operational Data Management			
Planning Tools	◕	◕	◕
Operational Systems	◑	◔	◔
Automated Field Reclosers	◑	◔	◔
APPLICATIONS			
Smart Meters	◔	○	○

The blue-shaded area in each of the Harvey balls in the table represent the state of progress:
- A fully white ball means no technology has been deployed.
- A fully blue Harvey ball indicates the technology has been fully deployed.

5.2 GRID OPERATIONAL CONSIDERATIONS

Electricity is the life blood of Hawai`i's modern society and economy. This view was reinforced in both our customers' feedback and in recent surveys.[57] It is often easy to forget the role of electricity when considering more recent innovations. For example, the Internet certainly has fostered productivity gains and new business models over the past 20 years. Also, the

[57] Center on the Family, College of Tropical Agriculture and Human Resources, and University of Hawai'i – Manoa: Energy Report 2014 – Public Attitudes About Renewable Energy in Hawai'i: https://mauienergyconference.com/public-attitudes-about-renewable-energy-in-hawaii/

emergence of the Internet of Things[58] has led to opportunities to enhance lives and improve business productivity. However, these innovations are dependent on access to high-quality and reliable electricity. It is in this context that operational challenges should be considered and addressed.

The volume of distributed and customer-owned photovoltaic generation in Hawai`i has dramatically impacted the daily load-shape. There have been instances where mid-day loads, when PV production is highest, declines to below the evening minimum load levels, which have technical impacts as further described below. This is not unique to Hawai`i, since California has experienced the same issue as illustrated in the CAISO "duck curve."[59] However, Hawai`i has a more acute set of challenges both for the bulk power system and on certain distribution circuits with very high levels of DER—DG-PV specifically. Unlike California that is interconnected to neighboring states, variability in generation caused by varying weather patterns must be compensated by energy storage or other generating equipment.

5.2.1 Transmission System

As outlined in Appendix D of the PSIP, the generation resources serving the Companies' customers consist of both utility-owned generation as well as customers' variable distributed generation. This represents a shift in generation resources where customer based variable distributed generation will increasingly become a substantial generation resource on the grid. This shift is challenging the Companies' ability to maintain system balance, especially absent visibility of the distributed resources, as is the case today. In addition to managing the minute-to-minute and day-to-day variability inherent in grid operations, the level of uncontrolled distributed generation is creating an even more dynamic balancing situation. System-level generation requirements are changing across the islands as the result of the changing resource mix, variability and uncertainty attributed to weather, and lack of visibility and control of distributed generation resources.

Figure 10 illustrates system-level challenges on O`ahu from 2013 to 2017. At a high level, the figure depicts the following characteristics:

- Daytime minimum load served by the Companies is occasionally decreasing to the point that it is lower than the overnight minimum load;
- Variable output from renewable generation throughout the day results in significant ramping requirements from bulk system resources; and
- While the amount of solar connected to the system exponentially grew, the peak demand remains relatively unchanged.

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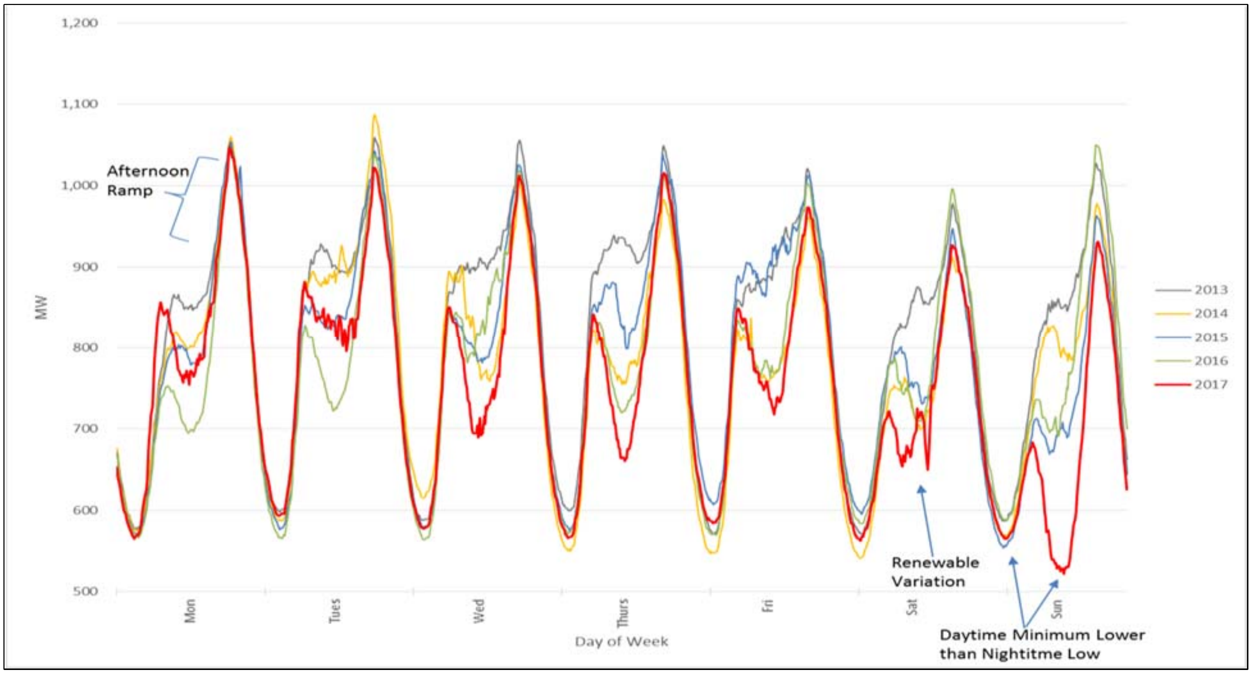
[58] Cisco – Internet of Things Overview – "Connecting everything drives positive business results": http://www.cisco.com/c/en/us/solutions/internet-of-things/overview.html

[59] California Independent System Operator – "What the duck curve tells us about managing a green grid": http://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf

Figure 10 O`ahu System Load Fourth Week of January 2013–2017



These trends in grid operation have important economic implications:

- Traditional Generating resources that are ramped to balance supply and demand are being displaced, along with the ancillary services provided by these resources, such as frequency response, rotational inertia, and fault current among others. As the daytime minimum has become lower than the nighttime minimum, dispatchable generating resources are increasingly being taken offline to accommodate production from both grid-scale renewable energy resources and DER.
- The need for flexible dynamic resources is increasing. As the grid becomes more dynamic, the need for resources that can regulate grid frequency and provide fast frequency response is increasing, as indicated by the variability observed during the day.

With the existing grids, the economic impact of these effects has generally reached the point of being negative. The operating efficiency of existing generating units on the system is compromised because they are increasingly being operated at lower outputs (sometimes at minimum output) and on-off cycling (start-up and shut-down) is becoming more frequent. On highly variable days, additional generation capacity must be kept online (as ancillary service spinning reserves) in order to ramp up and ramp down output and balance supply and demand as variable and intermittent renewable generation resources fluctuate. During periods of high variable generation, grid-scale renewable generation is sometimes curtailed to maintain sufficient upward-reserve capacity from dispatchable units (at times, minimum output), since all of the DG-PV installed to date is not controllable. However, these traditional dispatchable

resources may be needed to maintain an acceptable level of rotational inertia, and short-circuit current must be maintained to ensure system stability.

Moreover, these system challenges, which are inherently complex, are all the more difficult given the lack of operational data and control of DER systems. With the increasing amount of distributed generation, there are corollary concerns for implications with respect to both system frequency and bulk-system regulation. For example, on February 25, 2017 a break in cloud cover across a portion of O`ahu caused system frequency to spike unexpectedly. Simultaneously, the grid-scale renewable generation did not fluctuate because cloud cover remained over those solar resources. These types of frequency instability events will occur with increased frequency and magnitude if the generation and T&D systems are not updated. However, a combination of flexible generating resources and better situational awareness, would allow the system operator to mitigate such events.

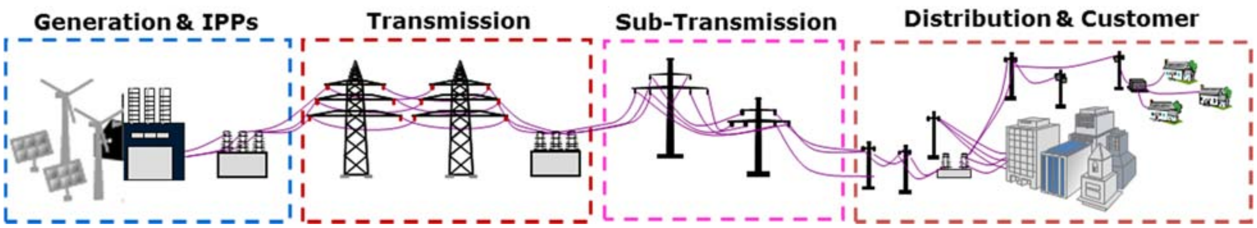
This type of issue was also recently identified by the North American Electric Reliability Corporation (NERC) in their DER report that called for greater situational awareness of DER performance.[60] NERC is the entity accountable to the U.S. and Canadian governments to ensure electric system reliability. The Companies have begun investments to increase the visibility capabilities across the grid. However, the proliferation of DG-PV in recent years has outpaced the ability of the Companies to keep pace with appropriate levels of sensing, measurement, operational analytics, and technologies to manage system frequency and stability.

5.2.2 Distribution System

Traditional distribution systems are typically designed radially for one-way power flow (as illustrated in Figure 11) and have decreasing capacity as electricity flows from the transmission system across the distribution feeder to individual customers. This is not unlike a water system that has decreasingly smaller-sized pipes from the main line to a house (and inside the home). This is important to consider as distributed customer generation with output in excess of the customers' demand was not factored in the design of the current distribution grid. As a result, areas with high customer concentrations of DG-PV can have generation output that exceeds the capability of the conductors or voltage issues caused by the reverse flow of power. The limit of DG-PV that a circuit can accommodate is known as circuit hosting capacity.

[60] NERC Distributed Energy Resources Connection Modeling and Reliability Considerations February 2017: http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf

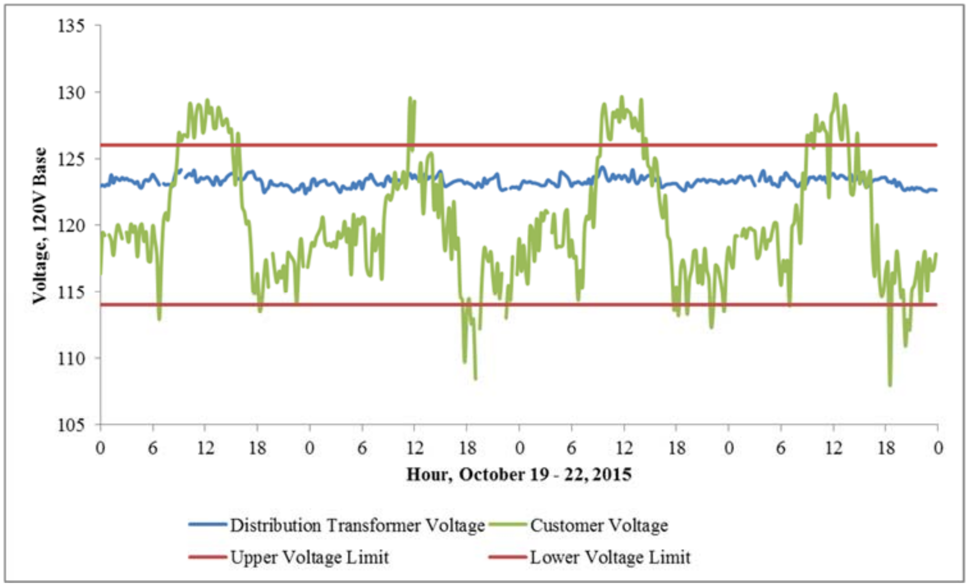
Figure 11 Traditional Power System



Distribution systems can typically accommodate DER up to the circuit hosting capacity with little to no negative impacts on the circuit performance or quality of service for customers. However, when penetrations of DER exceed hosting capacity, counter-balancing DER services and/or distribution infrastructure is necessary to prevent undesired impacts related to voltage violations, thermal overload, or compromising protection. Additionally, variability in the output of DG-PV systems over short time frames – seconds to minutes – can be much more drastic than when customer demand was the only variable. This variability can create voltage fluctuations that degrade the quality of service to nearby customers.

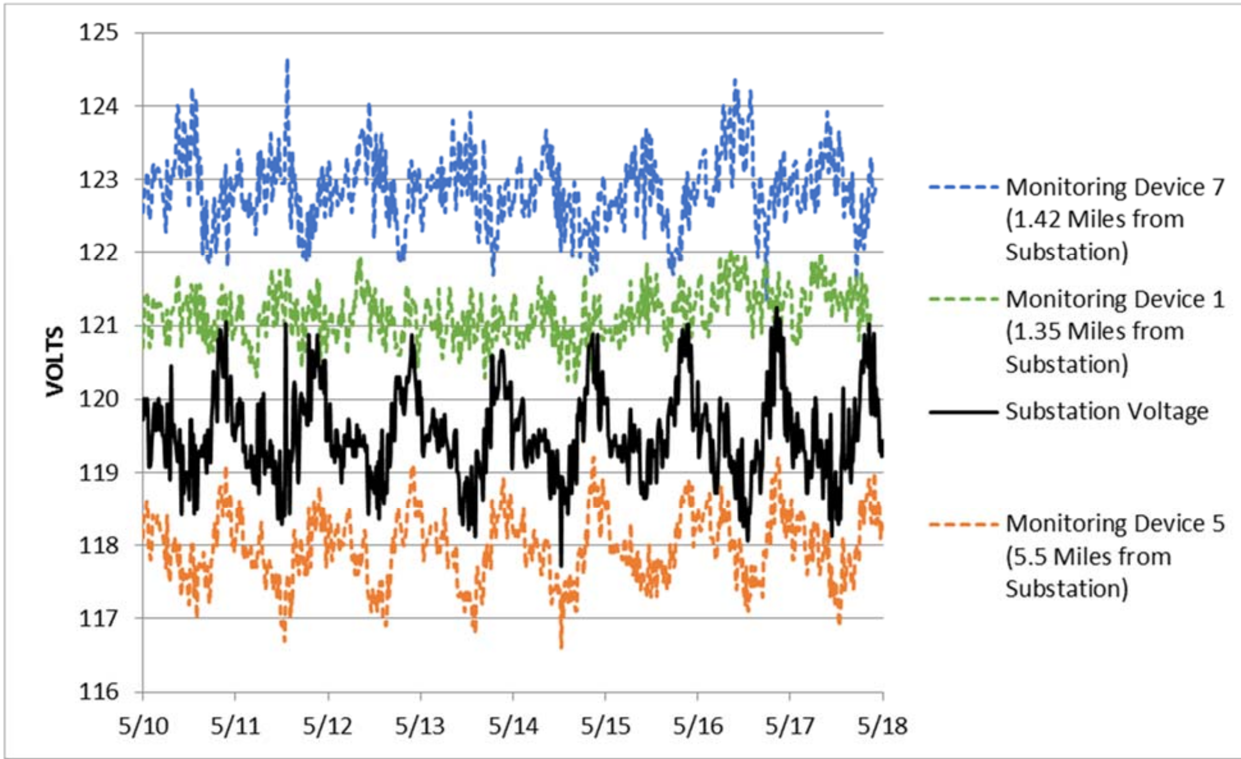
As discussed in *Rooftop PV interconnections: A Methodology of Determining PV Circuit Hosting Capacity* filed in Docket No. 2014-0192 on December 11, 2015, the Companies analysis of the distribution system concluded that continued PV growth will require solutions to mitigate voltage power quality issues, conductor and equipment overloads, and operational flexibility deficiencies. For example, the Companies have recorded high voltage conditions caused by PV. Figure 12 illustrates one real-world example where PV caused voltage to rise during daytime hours with actual data captured at the distribution transformer and the customer's meter. This particular customer installed a 10 kW PV system which clearly caused voltage to rise during the peak solar hours (i.e. noon), as compared to the voltage seen at the distribution transformer (monitoring point). The approximate 6-7 volt rise seen between the monitoring point (blue line) and the customer (green line) caused the customer's PV to violate the prescribed voltage limits of national standards and Hawaiian Electric power quality rules. This level of voltage deviation, for example, can cause customer equipment to trip causing disruptions to their business.

Figure 12 Voltage Readings at a Customer's Meter and Related Distribution Service Transformer



In Figure 13, the readings from distribution monitoring devices are compared with the system readings collected from the substation feeder head. Figure 13 illustrates that voltages can vary throughout a circuit depending on DG-PV generation, load characteristics, distance from the substation, and other factors. For example, measurement device 5 in Figure 13 is 5.5 miles away from the substation, and shows a voltage drop relative to the substation voltage. Measurement devices 1 and 7 are little over a mile away from the substation and show varying degrees of voltage rise relative to the substation. This highlights the need for increased analytics and situational awareness so that the system operators can monitor and utilize distributed resources safely and reliably. Measurement and sensing only at the substation is no longer sufficient. This data is currently being used for planning purposes to validate modeling, correct field discrepancies, and identify areas that have the hosting capacity for the interconnection of more DG-PV.

Figure 13 May 2017 Voltage Deviations on a Feeder From Distribution Monitoring



5.2.3 Research & Technology Pilot Projects

The Companies have pursued several research studies to understand these operational challenges and potential mitigation measures with partners such as the National Renewable Energy Laboratory, and HNEI. Also, several technology pilots have been conducted on power electronics and smart inverters to manage volt-var, demand response for ancillary services, and second-generation smart meters. Given the importance of customer service quality and the scale of the voltage issues on the distribution grid, the Varentec secondary var controller pilot is highlighted below. This is only one example of several promising advanced technologies that the Companies are proposing to use in this strategy.

5.2.3.1 Secondary Var Controller

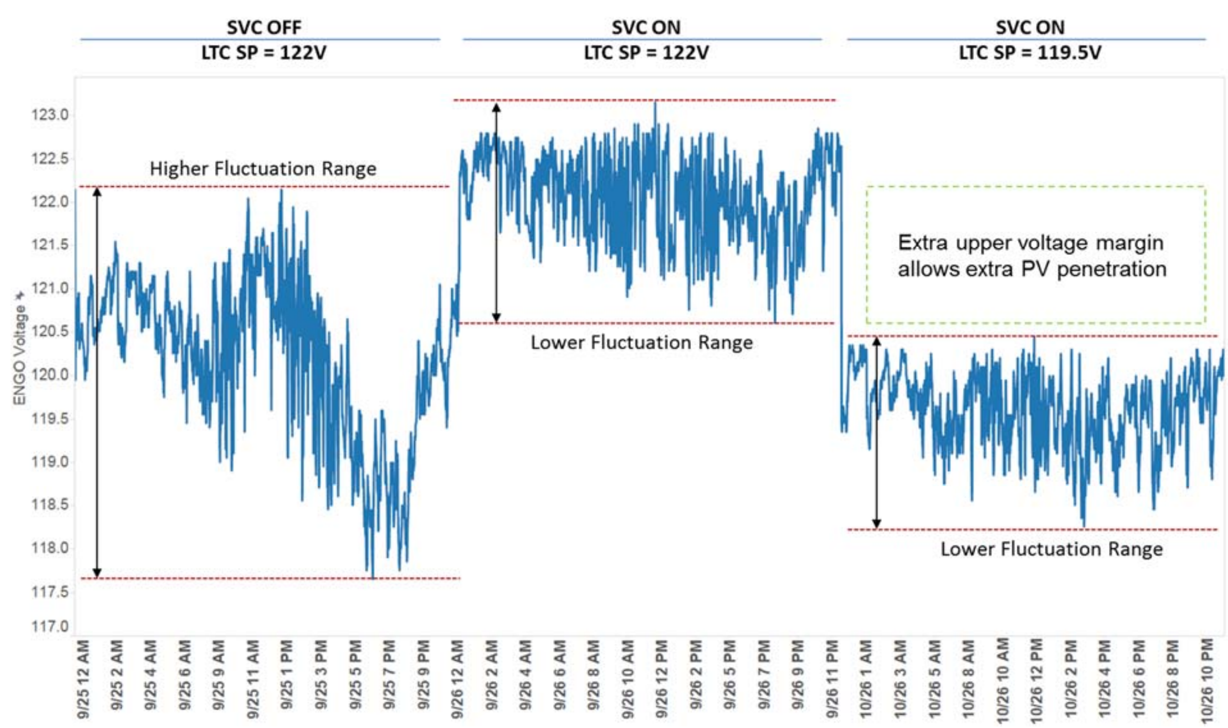
Advanced inverters set with autonomous functionality will mitigate some of the voltage issues associated with high concentrations of DG-PV. Advanced inverters alone, however, cannot mitigate the impact of legacy inverters, and distribution system solutions are needed to maximize the capacity of existing circuits. One of the promising technologies to augment advanced inverter functionality is through the deployment of grid-connected secondary var controllers (SVCs).

Commercially available SVCs use power electronics–based, fast-acting, decentralized shunt-var technology for voltage regulation. Each device connected to the secondary side of a pole-

or pad-mounted service transformer can inject vars and can regulate the voltage tightly (± 0.5% within control range) locally and feeder-wide. The devices are autonomously controlled once a set-point is dispatched via the utility supervisory control and data acquisition (SCADA) or DMS system. They can also provide system monitoring capability if a telecommunication path is available. A DOE ARPA-e program[61] focused on the development of this technology for precisely this application.

Hawaiian Electric conducted a pilot on O`ahu at the Keolu Substation to validate the performance of this technology to mitigating voltage quality issues, which would then allow more private rooftop solar systems to be added to the distribution grid. The pilot project deployed 61 fast-acting SVC power-electronics devices from Varentec (an ARPA-e grantee) that are installed on the secondary side of a distribution circuit. These devices autonomously sense and regulate voltage by injecting vars to intentionally flatten the primary and secondary feeder voltage. Figure 14 shows the voltage flattening effect of these secondary var controllers.

Figure 14 Varentec Pilot Results for Voltage Support



The pilot confirmed that this simplified and automated system enables greater penetration of DG-PV and prevents strain on grid infrastructure. Importantly for customers, the pilot demonstration project improved the simulated static hosting capacity from approximately 5 MW to 7 MW on the Keolu substation feeder.

[61] DOE ARPA-e GENI program: https://arpa-e.energy.gov/?q=arpa-e-programs/geni

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6 Customer-Facing Technologies

Grid modernization must create value and engage customers in several dimensions. This evolution and interface involves:

- Enabling customers to have greater control of their energy bill;
- Providing customers contextual information regarding their electric service, such as outage information;
- Collaborating with customers in relation to pertinent operational information through social media; and
- Embracing the opportunity for customers and others to co-create services that can be used to manage the power system.

These are the key dimensions of customer engagement in relation to the operation of the grid. Many more aspects of engagement are related to customers' service experience outside the scope of grid modernization. The discussion that follows highlights the strategy within the scope of grid modernization and related customer-facing technologies.

A second, more holistic aspect of customer engagement is the role that clean electricity plays in Hawai`i's economic development. The Internet of Things is a profound development that is positively benefiting customers' lives and industries. However, the electric grid itself has empowered economic growth and enabled innovations like the Internet for almost 100 years. A modern grid integrated with the islands' telecommunications, water, and transportation (i.e., rail, port, and vehicle) systems has the potential to create synergistic value that can continue to enable further economic growth. This is the goal of many "smart city" efforts, and this grid modernization strategy can be an integral part of and facilitate this future.

> *Customers want choices to manage their energy costs and reliable, quality service – technology is seen as a means to this end.*

6.1 CUSTOMER IN CONTROL THROUGH INFORMATION

Customers want information to manage their energy bills and service. For example, information on energy consumption, service quality, energy efficiency and other distributed resource options. This information allows them control of their budget and other aspects of

service. This is enabled through advanced metering and a customer portal that enables customer access to their account, consumption and service information. This is expanded through decision support tools to assist customers on the wide range of options to manage electric costs and electric vehicle purchase decisions.

6.1.1 Advanced Metering

In the period of time since Hawaiian Electric evaluated metering technologies for the March 2016 Smart Grid Foundation Project application,[62] smart metering has advanced. A new generation of advanced metering is commercially available that combines previous generation functionality with new levels of integrated grid sensing, computing, and open standards communications. Advanced meters are becoming communications agnostic in order to interface with most of the telecommunication platforms available. These advanced meters are designed to enable both grid modernization functions and traditional AMI capabilities for customer operations.

Advanced meters are becoming grid sensing devices that are communications agnostic to be able to interface with most commercially available telecommunication solutions

New sensing capabilities include more complete power characteristic measurement and calculation (e.g., voltages and reactive power) in residential meters. Commercial meters provide a full spectrum of power measurement. Additionally, these third-generation meters (the first generation was installed in the late 2000s) have improved the operational effectiveness of the outage notifications. Advanced meters also have capabilities to further enable data and information exchange with customers participating in the DR programs described in Section 6.4.1.

In a more distributed grid, the connectivity of devices to the electric network becomes critical. The physical connections and relationship between those components is not static as increasing switching and automation capabilities dynamically change the grid configuration. Advanced meters are beginning to incorporate technology to help understand the associations between meter and transformer; for example, advanced meters can improve public safety by identifying broken electrical neutral connections between the customer and the distribution transformer.

Also, meter manufacturers have enhanced the internal computing platform to enable applications. This platform enables utility applications that can be downloaded similar to downloading an application on a smart phone. For example, an application could be developed to provide interaction between the advanced meter and intelligent reclosers described in

[62] HPUC Docket No. 2016-0087, Application For Approval to Commit Funds in Excess of $2,500,000 for the Smart Grid Foundation Project

Section 7.3.2, with the advanced meter providing actionable data to the recloser to coordinate feeder switching with changing loads after an outage caused the DG-PV to trip.

The ability of the meters to interact and exchange information with other devices connected to the common communications network is called peer-to-peer communications. This was not possible with prior generations of smart meters. Peer-to-peer capability is foundational for meters and other devices in a modern grid where localized sensing and control is desired.

Also, unlike earlier smart meters and associated communications networks, these third-generation meters are becoming communications agnostic through Wi-Fi-like interfaces so that they will be able to connect to any telecommunication platform that is available. A new standard, Wi-SUN, is designed to provide this flexibility, which was identified by the Commission in its order. This type of standard, combined with the communications architecture discussed in Section 7.5, will enable proportional deployment at the pace of customer value. With a common multi-purpose communications infrastructure to enable both grid modernization and advanced metering, these solutions can be tactically deployed to customers participating in DR, DER, DG-PV, and pre-pay programs or to areas that are experiencing issues such as hosting capacity constraints, frequent outages, or power quality issues.

Safety is always the first priority. Advanced meters can now monitor both meter socket and ambient temperature as well as disconnect the meter from the premises if a temperature threshold is exceeded. Additionally, many studies have investigated health concerns associated with advanced meters. The normal operation of advanced meters includes radio frequency transmissions from the meter, and these communications occur with very low duty cycles, at average power levels far below safety standards specified by the Federal Communication Commission (FCC).[63]

The Smart Grid Foundation project had proposed the rollout of advanced meters to all customers. This approach has been refined to align with the proportional approach described for this grid modernization strategy. The revised approach can be summarized as "meters for enhanced sensing and monitoring," with meters proportionally deployed as needs arise.

6.1.2 Customer Information Portal

Access to data is a key part of enabling customer choice and control. As distribution grids are transformed into integrated grids that support the two-way flow of data and power, the overall power environment moves from one of low data intensity to one of high data intensity. Customers that currently have smart meters and are part of the Smart Grid Initial Phase pilot

[63] See EPRI, A Perspective on Radio-Frequency Exposure Associated With Residential Automatic Meter Reading Technology, 2010; Characterization of Radio Frequency Emissions from Two Models of Wireless Smart Meters, 2011: https://www.epri.com/#/pages/product/000000000001020798/

have access to an online portal, "My Energy Use."[64] From the online portal, they are able to see their energy use in 15 minute intervals, view future and past electricity usage/cost trends, and access their data utilizing the Green Button standard.[65] However, a new portal with Green Button functionality for customers and customer-authorized third party access will need to be developed, because the existing portal is limited to the Initial Phase Smart Grid pilot hosted by the communications supplier for the pilot. The new information portal will need to easily integrate with existing portals and information systems to provide a seamless experience to the customer.

The Companies also have additional online tools for customers to manage energy consumption and support decisions regarding solar PV and electric vehicles. Two examples of tools being developed and proposed for implementation as part of this effort are the A/C sizing calculator,[66] which helps customers determine what size of air conditioner matches their needs, and another calculator that helps determine appliance operating costs.[67] Also, customers are able to evaluate electric vehicle options based on their needs. [68]

Preserving customer privacy is a key aspect of being entrusted with customer data. For this reason, the Companies' policy is to protect the privacy of residential customers and the confidentiality of business customers. As part of the current privacy program, the Companies actively participated in the creation of the U.S. DOE's January 2015 Data Privacy and the Smart Grid: A Voluntary Code of Conduct. Now branded as DataGuard, this program represents the culmination of numerous federal initiatives that preceded it.[69] The Companies are currently modifying and updating policies and practices to adopt DataGuard.[70]

[64] Hawaiian Electric Companies - My Energy Use Portal: https://www.hawaiianelectric.com/clean-energy-hawaii/smart-grid-and-smart-meters/my-energy-use-portal

[65] 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.

[66] Hawaiian Electric Companies A/C Sizing Calculator: https://www.hawaiianelectric.com/save-energy-and-money/calculate-energy-consumption/a/c-sizing-calculator

[67] Calculate Appliance Operating Costs: https://www.hawaiianelectric.com/save-energy-and-money/calculate-energy-consumption/calculate-appliance-operating-costs

[68] Hawaiian Electric Companies - WattPlan for Electric Vehicles: www.hawaiianelectric.com/WattPlanforEV

[69] Previous federal initiatives include the Privacy Act of 1974; the Federal Trade Commission's privacy report, Privacy Online: A Report To Congress, Federal Trade Commission, June 1998 (http://www.ftc.gov/sites/default/files/documents/reports/privacy-online-report-congress/priv-23a.pdf);):(http://www.ftc.gov/sites/default/files/documents/reports/privacy-online-report-congress/priv-23a.pdf); the Federal Trade Commission's "The Red Flags Rule" issued in 2007 published at 16 C.F.R. ' 681.1. See also 72 Fed. Reg. at 63,771 (Nov. 9, 2007) (http://www.ftc.gov/os/fedreg/2007/november/071109redflags.pdf););(http://www.ftc.gov/os/fedreg/2007/november/071109redflags.pdf); the U.S. Department of Homeland Security's Policy Guidance Memorandum, December, 2008 (http://www.dhs.gov/xlibrary/assets/privacy/privacy_policyguide_2008-01.pdf););(http://www.dhs.gov/xlibrary/assets/privacy/privacy_policyguide_2008-01.pdf); and the National Institute of Standards and Technology (NIST) 7628 Revision 1, Guidelines for Smart Grid Cybersecurity, Volume 2 - Privacy and the Smart Grid, 2014 (http://nvlpubs.nist.gov/nistpubs/ir/2014/NIST.IR.7628r1.pdf).).(http://nvlpubs.nist.gov/nistpubs/ir/2014/NIST.IR.7628r1.pdf).

[70] Hawaiian Electric Companies - Privacy Policy: https://www.hawaiianelectric.com/privacy-policy

The Companies understand and are vigilant about mitigating the potential risks posed by the implementation of customer-facing and grid technologies. Customer information and privacy is one of the Companies' highest priorities. That is why, in addition to existing cybersecurity systems discussed in Section 7.6, the Companies have extensively prepared their operational configurations to protect against any unwarranted intrusion or cyber-attacks on a modernized grid.

6.2 CUSTOMER CONTEXTUAL INFORMATION

Hawaiian Electric launched its O`ahu Outage Map at the end of October 2016.[71] The online map provides customers with information on status and allows them to report their outage online instead of calling the trouble line.[72] The outage map displays all known outages, while major outages are pushed proactively through social media channels. Also, customers are able to evaluate rooftop solar options through another shopping tool, where the customer inputs location and usage information and the tool estimates what size PV system may be appropriate and summarizes the different financing options. [73]

6.3 CUSTOMER COLLABORATION

As the Companies focus on improving overall customer satisfaction, social media plays an important role in interfacing with customers. Engagement and social listening enable us to share and receive relevant information with and from customers and use that information to make smarter business decisions. In order to do this, the Companies utilize social media to enhance customer service, build a relationship with the communities, and provide thought leadership.

> *Engagement and social listening enable us to share and receive relevant information with and from customers and use that information to make smarter business decisions.*

Customers often reach out either proactively or indirectly by sending messages or posting statements on their social media accounts. In both situations, the Companies' practice is to quickly acknowledge a customer's complaint or issue and work with internal departments to resolve the issue, depending on the situation. Customer service issues can range from getting information about a customer's electric bill and facilitating payments, to receiving an update

[71] O`ahu Outage Map: www.hawaiianelectric.com/outagemap

[72] Hawaiian Electric Companies – Report an Outage: www.hawaiianelectric.com/reportoutage

[73] Hawaiian Electric Companies - WattPlan for Solar: www.hawaiianelectric.com/WattPlan

on their distributed energy resources' rooftop solar application. Social media provides an opportunity to engage in real-time two-way communication. Most customers are grateful for the quick response and happy to speak with someone that may help address their issues and concerns.

For all social media channels, the Companies build online social communities by sharing news regarding community events, programs, and energy-saving and safety tips. Depending on the social media channel, the content is disseminated in a way to help garner the most views and expand reach to customers.

The Companies communicate and correspond with our customers through different forms of social media. For example, videos that have been created to share knowledge regarding how the existing system works from a reliability standpoint and how solar needs to be equitable for all customers include the following titles:

- Maintaining Safe and Reliable Energy for Customers[74]
- Managing a Two-Way System to Integrate More Renewable Energy[75]
- A Sustainable Solar Future for Hawai`i[76]

All online efforts are focused on building trust and transparency with our customers. In 2014, the Hawaiian Electric Companies launched their Facebook and Twitter accounts and took a proactive approach to engage with customers in the social media space. Prior to that, we had made some use of YouTube and Flickr. Only when the Companies launched our official Facebook and Twitter accounts did we start being a part of the social media conversation. Most of the social media accounts are consolidated into one account representing Hawaiian Electric, Maui Electric and Hawai`i Electric Light collectively as the Hawaiian Electric Companies.

The Companies' Twitter campaign was created with separate accounts for the three companies to account for proactive outage notifications. Real-time proactive outage notifications are pushed through Twitter and Facebook/Instagram if the severity of the outage and the number of customers affected warrants getting the message out to a broader group.

With social media the Companies get feedback directly from customers in real time. The Companies first started off with the Hawaiian Electric account (@HwnElectric) on Twitter and Hawai`i Electric Light and Maui Electric companies followed shortly afterward. In August 2014, Tropical Storm Iselle hit the islands and Instagram allowed customers to share photos of the damages and impact from the storm. Decisions were then made on what updates needed to be included for communication to customers through news releases and postings on social media. The Companies opened a Customer Information Center on Hawai`i Island to help

[74] Hawaiian Electric Companies - Maintaining Safe and Reliable Energy for Customers: https://youtu.be/QECzuo8WD4I

[75] Hawaiian Electric Companies - Managing a Two-Way System to Integrate More Renewable Energy: https://youtu.be/nH47jRCk5cw

[76] Hawaiian Electric Companies - A Sustainable Solar Future for Hawai'i: https://youtu.be/IA2Z48nlDoQ

customers stay informed about the progress of the restoration efforts and images were shared by customers and reposted on the Companies' social media accounts.

6.4 CUSTOMER CO-CREATION

Customer co-creation involves utilizing customer DER and energy conservation as instrumental resources to manage the power system efficiently and reliably. Given the role that DER will increasing play to enable the state's renewable goals it is essential to engage customers and aggregators proactively to participate in programs and procurements. The term "prosumer" has also been used to describe those customers that both consume and produce energy and related services. The act of prosumers providing services to the grid is co-creation. The Companies demand response programs, DER aggregation procurement are current efforts at leveraging customer DER. The rise of customer battery energy storage is expected to play a key role in enabling dispatchable distributed supply resources in addition to dispatchable demand resources.

6.4.1 Demand Response Programs

The Companies' proposed DR portfolio creates the economic and technical means by which customers can use their own equipment and behavior to have a role in the management of the electric grid. The Companies' DR initiatives will result in a more flexible and reliable grid while at the same time empowering customers with expanded energy options and economic opportunity.

The Hawaiian Electric Companies' DR portfolio application was filed in accordance with Order 32054,[77] Policy Statement and Order Regarding Demand Response Programs (DR Policy Statement), issued by the Commission on April 28, 2014, and in accordance with the Companies' Integrated Demand Response Portfolio Plan (IDRPP).[78]

The Companies have requested approval for DR programs focusing on four system-level grid service tariffs and a selection of riders to allow customers to deliver the following programs:[79]

1. Capacity programs that compensate customers for providing DR services to the grid through time-of-use (TOU) rates, real-time pricing, critical peak incentives (CPI) and/or day-ahead load shifting

[77] HPUC Policy Statement and Order Regarding Demand Response Programs, Docket No. 2007-0341, April 28, 2014: http://puc.hawaii.gov/wp-content/uploads/2014/04/Order-No.-32054.pdf

[78] The Companies' IDRPP was filed on July 28, 2014, and updated on March 31, 2015 (IDRPP Update). http://puc.hawaii.gov/wp-content/uploads/2014/08/HECO-Companies-Integrated-Demand-Response-Portfolio-Plan-07-28-14.pdf

[79] HPUC Docket No. 2014-0192, Distributed Energy Resources Policies and Docket No. 2015-0412, Demand Response Portfolio Structure.

2. Fast frequency response (FFR) programs that compensate customers on O`ahu for providing a load-reducing response following a contingency scenario (e.g., a generation trip)
3. Regulating reserve programs that help the Companies to balance their electric grids by operating DR resources in response to automatic generation control signals from the energy management system
4. Replacement reserve programs that compensate customers for providing load-reduction in place of the Companies starting a fast start generator

DR Programs will enroll customers in programs that control customers' equipment to increase or decrease their electricity demand. Customers can utilize many end-use devices to provide DR, including water heaters and air conditioners, and in the future potentially alter charges or dispatch schedules of behind-the-meter storage and EVs. The goal is to utilize DR to support grid reliability and stability.

6.4.2 Customer-Sited Energy Storage

Customer sited energy storage can enable more DER on distribution circuits, but proper coordination and controllability of these resources is essential to maximize the benefits they can provide. Customer storage systems promise an array of potential benefits for customers as well as company operations, including the following:

- Storing excess energy
- Time-shifting the net customer demand away from on-peak periods
- Avoiding the need to add capacity to serve peak loads
- Smoothing ramping due to daily and transient changes in output from large-scale renewable generation installations
- Smoothing the net load from customers with similarly variable renewable generation
- Improving customer experience through better reliability and resiliency on site
- Deferring investments in new or upgraded transmission capability
- Serving markets for ancillary services such as operating reserves and frequency or voltage regulations

Today, customers are taking advantage of opportunities to install energy storage in an effort to manage their energy bills.

- Hawaiian Electric installed 499 grid-interactive water heaters[80] at Kapolei Lofts, a rental housing development in West O'ahu. The installation tests demand response technology and its ability to shift demand or provide regulation services.
- Commercial customers participated in a pilot program that deployed nearly one megawatt of intelligent battery energy storage to optimize their use and reduce

[80] http://www.bizjournals.com/pacific/news/2016/07/13/forest-city-puts-499-unit-west-oahu-rental-complex.html?ed=2009-07-27

demand charges, with benefits to the grid through demand response program participation.[81]

- Over 750 customers have opted to participate in the customer self-supply program, which provides the option to install a battery system in combination with PV[82]. These customer self-supply systems not only benefit a customer's management of energy bills, but also are in a position to participate in future demand response programs to provide grid support.
- Numerous other customers simply install energy storage for added resiliency to power critical loads in the event of a power outage.

The Companies will continue to develop co-creation opportunities with stakeholders and customer to find symbiotic opportunities for customer-sited energy storage.

6.5 SMART CITIES & COMMUNITIES ECONOMIC GROWTH

Many cities and communities around the country are participating in a dialogue about how to leverage technology innovation to transform themselves into "smart cities." One of the goals of a smart city transformation is to create cities that would be interconnected, via the Internet of Things, and allow a free flow of data that can both enhance existing city functions as well as create new ways to positively impact the communities they serve through synergistic value from integrated critical infrastructure such as water, telecommunications, transportation, and electricity. As noted in a recent Forbes article:[83]

> "As more smart cities emerge, embracing technology and learning from the insights that big data offers, we will likely see a new business strategy emerge–geo-collaboration. When we think of cities now, we typically envision businesses, systems, and people operating among one another with almost no connection or collaboration. Now, imagine what will happen once cities become more connected and smart? Once local companies realize the value they could create together through interconnectivity, the possibilities are virtually endless."

These discussions have much in common with transformation of the grid. One key concept that has emerged is the idea of convergence. Convergence of networks can create strong economic benefits for communities, businesses, and customers as well as the infrastructure owners. The opportunity to converge two or more networks arises from the potential to

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[81] https://www.hawaiianelectric.com/hawaiian-electric-and-stem-inc-successfully-test-1-mw-of-energy-storage-at-29-commercial-customer-sites

[82] See, Weekly Report – week ending 2017-06-13, filed in Docket No. 2014-0192 on June 20, 2017.

[83] D. Newman, Smart Cities May Turn Competition Into Collaboration, Forbes, November 25, 2016 https://www.forbes.com/sites/danielnewman/2016/11/25/smart-cities-may-turn-competition-into-collaboration/#39eee58a395f

integrate various elements of the respective networks or systems in the context of resources sharing common infrastructure. This integration is intrinsically synergistic. The convergence of the electric network with other critical infrastructure along with social and economic networks is the energy Internet of Things.[84] A modern distribution system as envisioned in this strategy allows the value of convergence to grow.

One example is the opportunity to leverage the operational flexibility of water pumping and wastewater treatment to manage the dynamics on the power system through adjustments to pumps and processes without impacting the quality or production of water. Another is the deployment of 5G cellular service on Hawai`i, the need for highly reliable electricity to power this new network, and the opportunity to collaborate with other service providers in a mutually beneficial way for all customers. Other telecommunications opportunities include leveraging the implementation of Spectrum's fiber optic cable for substation communications in return for access to utility poles and other infrastructure. A final example is the potential to leverage the new field of wireless communications for smart LED street lighting control for communities to manage energy and improve public safety. These modest first examples are expected to grow as the Companies draw insights from global smart city efforts.[85,86]

Microgrids that encompass more than one building are part of this smart community discussion. As the DOE has defined it,[87] a microgrid interoperates with the grid in a manner that is coordinated and can provide benefits to the grid as well as to customers/communities. This holds whether the microgrid is developed by the utility or another entity. This strategy contemplates the ability of the integrated grid planning process to cooperatively develop microgrids with communities and customers.

6.5.1 Electrification of Transportation

Electrifying the transport of people and goods in Hawai`i is an important opportunity to capture the synergistic value of clean energy to reduce greenhouse gases while also reducing the net cost of the grid for all customers through more efficient utilization. With Hawai`i's planned 100 percent RPS by 2045 and its goal to reduce greenhouse gas emissions to 1990 levels by 2020, the electrification of transportation becomes even more compelling because it enables reductions in fossil fuel use. Many of the electrification of transportation (EoT) growth opportunities also offer flexibility in the timing of their energy consumption, opening the possibility of the technologies being an essential resource for integration of renewables. Hawaiian Electric has detailed many of these opportunities in its 2017 Test Year Rate Case

[84] P. De Martini and J. Taft, Value Creation Through Network Integration & Convergence, Caltech-PNNL, 2015 http://smart.caltech.edu/papers/ElectricNetworksConvergence_final_022315.pdf

[85] Meeting of the Minds - http://meetingoftheminds.org/

[86] Smart Cities Council - http://smartcitiescouncil.com/

[87] The U.S. Department of Energy's Microgrid Initiative: https://energy.gov/sites/prod/files/2016/06/f32/The%20US%20Department%20of%20Energy%27s%20Microgrid%20Initiative.pdf

filing to the Hawai'i PUC.[88] EPRI has also conducted research to characterize many of these opportunities.[89,90]

EoT in Hawai`i not only includes ground transportation but also airport activities and harbor equipment. Stakeholders for each of these groups are coming together around a shared vision for EoT in Hawai`i. In addition, stakeholders from the Companies, the public sector, and non-profit organizations have signed a memorandum of understanding called the "Drive Electric Hawai`i Initiative" that will set forth a shared vision of powering ground transportation using 100 percent renewable energy. The "Drive Electric Hawai`i Initiative" is aimed at cost-effectively electrifying transportation by strategically placing incentives to achieve the optimal transition to EVs. The strategy and incentives are necessary since it is widely agreed that the optimal level of EV adoption is much greater than the level that would occur organically.

The electrification of transportation represents a significant opportunity to assist in achieving Hawai'i's 100% renewable energy goal

The Companies have organized their EoT efforts under four categorical themes:

1. **EV Adoption Leadership** – The Companies are also implementing several initiatives to "lead by example" and raise awareness of the benefits of EVs.
2. **Stakeholder Partnership** – The emphasis is on developing initiatives as partnerships, including public-private partnerships for funding and a greater likelihood of successful implementation.
3. **Trusted Partner/ Advisor** – The Companies will work collaboratively with their customers to facilitate and participate in educational programs, online product developments, and societal impact analyses to address EoT.
4. **EoT Investment / Innovation** – The Companies plan to lead the way in defining charging infrastructure needs and will explore innovative EoT policies, programs, rates, and tariffs to maximize EV benefits for all of Hawai`i.

The EoT represents a significant opportunity to assist in achieving the 100 percent renewable energy goal, but only if properly planned for and leveraged. The Companies do not plan to merely accommodate EVs but to leverage the emerging technology as an asset.

[88] Hawaiian Electric, HPUC Docket No. 2016-0328, Application for Approval of General Rate Case and Revised Rate Schedules and Rules.

[89] Initial Data for Non-Light-Duty Electric Transportation Options. EPRI, Palo Alto, CA: 2017. 3002009754.

[90] Assessment of a Full Electric Transportation Portfolio, Volume 1: Background, Methodology, and Best Practices. EPRI, Palo Alto, CA: 3002006875 (The executive summary for this three-volume series is provided in EPRI report 3002006881): https://www.epri.com/#/pages/product/3002006881/

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7 Grid-Facing Technologies

This section identifies technologies and strategies needed to transition from the current state of the grid toward our vision of a reliable grid affordably served by renewable energy. Given the multiple unknowns for future grid use, this strategy enables a platform to accommodate multiple possible future scenarios rather than assuming a single path forward. As described in Section 3.2, this strategy is based on developing the grid as a platform by which technology can be incrementally added and developed proportional to customers' needs while incorporating the flexibility to adjust to changing circumstances and leveraging future innovations. The platform requires certain foundational technologies, such as software, to enable the incorporation of new applications. Without the appropriate foundational technologies in place, no scenario for grid modernization is possible. The Companies believe that this strategy sets into motion the grid modernization that is necessary in Hawai`i by enabling a multitude of future scenarios. Figure 15 and Table 6 provide an overview of the components of a modern distribution grid.

Figure 15 Technology Components of the Envisioned Modern Distribution Grid

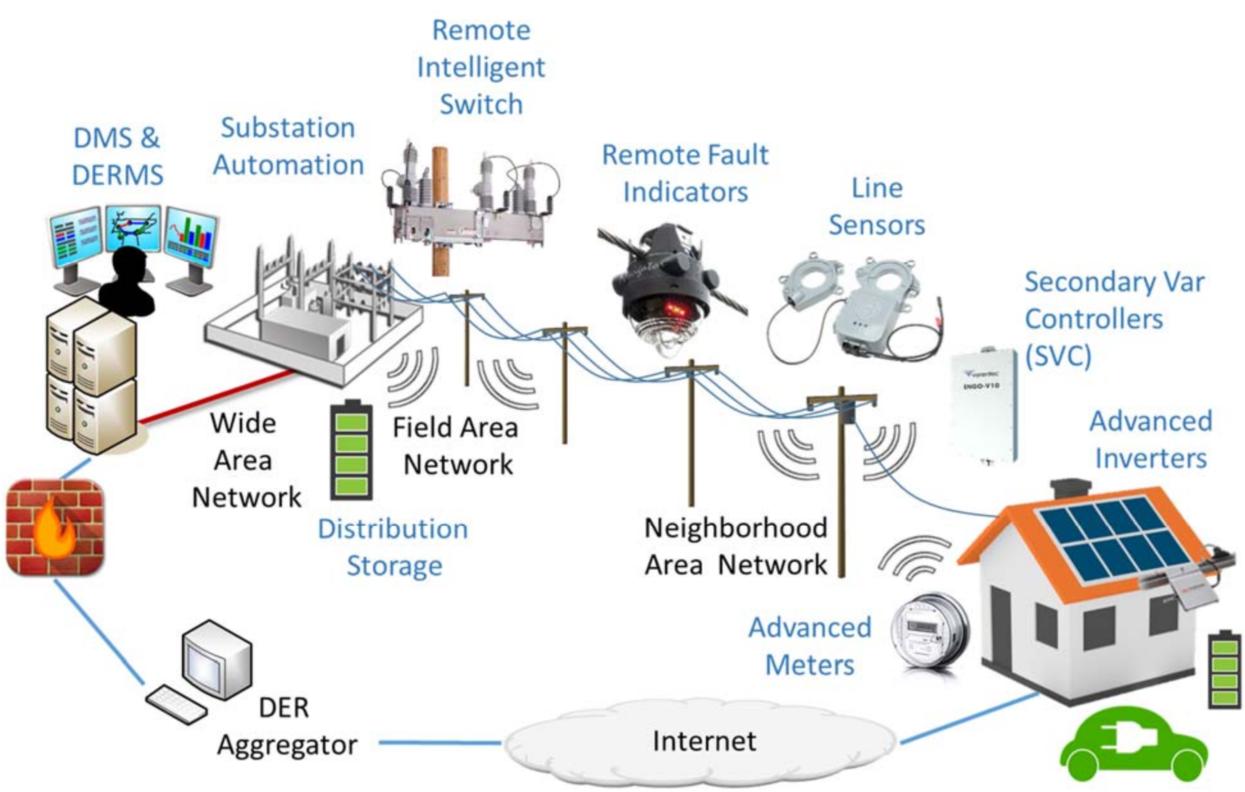


Table 6 Components of a Modern Distribution System

Category	Component	Description
Advanced Operational Systems	Distribution Operations Center (DOC)	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 Management System (DMS)	An operational system capable of collecting, organizing, displaying, and analyzing real-time or near real-time electric distribution system information. A DMS can also allow operators to plan and execute complex distribution system operations to increase system efficiency, optimize power flows, and prevent overloads. A DMS can interface with other operations applications, such as GIS, OMS, and Customer Information System (CIS) to create an integrated view of distribution operations.
	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.
	Outage Management System (OMS)	A system that 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 CIS, 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.
	Geographic Information System (GIS)	A software system that maintains a database of grid assets, including transmission and distribution equipment, and their geographic locations to enable presentation of the electric power system or portions of it on a map. GIS may also serve as the system of record for electrical connectivity of the assets.
	Situational Awareness	A software system that provides real-time visibility to grid and telecommunications network operations and operational data analysis for decision support

Category	Component	Description
Distribution System Components	Advanced Meters	Meters capable of two-way communication, advanced power measurement, computing platforms, outage and service quality information, and service switching.
	Faulted Current Indicators	Field devices that sense fault current to help determine the location of a fault and with communications capability.
	Remote Intelligent Switch (reclosers)	Sectionalizing and tie switches that enable shifting portions of one circuit to another for maintenance and outage restoration.
	Secondary Var Controllers (SVC)	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.
	Substation Automation	Utilizing data from SCADA and other intelligent electronic devices (IED) in combination with substation automation and control capabilities to manage substation operations.
Network Components	Wide-Area Network	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.
	Field-Area Network	The second level of a tiered utility communications structure connecting distribution substations and field devices such as field routers
	Neighborhood-Area Network	The third level of a tiered utility communication structure that connects reclosers, switches, capacitor banks, advanced meters, and utility-managed demand response devices such as A/C cycling devices.
Customer Assets	Advanced Inverters	Inverters for converting between direct current (DC) and alternating current (AC) with Hawai`i specific IEEE 1547 compliant (when available) voltage control from volt-var and volt-watt functions and greater resiliency during voltage or frequency deviations, with visibility into distribution system conditions via data collection. These inverters would operate autonomously.

Utilizing these and other grid technologies, situational awareness and grid control capabilities will evolve to address both current grid issues and begin the process of proactively utilizing data and technology to efficiently maintain a resilient and reliable grid. The proposed integrated grid-planning process will provide stakeholder input on the assumptions utilized in order to ensure that application of these technologies will economically meet customer needs.

7.1 PHYSICAL INFRASTRUCTURE

Efforts to modernize the grid must also take into account ongoing operations and maintenance efforts to replace aging infrastructure and components that fail during operation. A proportional approach to grid modernization will prioritize the components of the grid that must be upgraded to cost effectively and reliably meet customer needs and quality of service. Therefore, ongoing asset renewal programs for aging and problematic equipment provide opportunities to incrementally upgrade transmission and distribution infrastructure capabilities that support new functional requirements in coordination with other elements of this strategy.

Aging infrastructure replacement programs currently underway will incorporate modern grid technologies in coordination with the proportional deployment strategy.

Replacing significant quantities of older transmission and distribution infrastructure that are problematic (unsafe, obsolete, or high maintenance), failing, or nearing end of life, requires considerable, ongoing capital investment through asset renewal programs. In coordination with grid modernization, asset replacement will not be handled on a one-for-one or like-for-like basis. Rather, as assets are due for replacement, plans for their future integration into a modern grid are considered, and cost-effective technologies and functionalities are embedded in the infrastructure replacements being deployed. A potentially familiar analogy is that the Companies are planning to avoid paving the road twice, where the first pavement fixed the road surface and the second paving resurfaced the trench made to replace the under-road piping. This coordination between grid modernization and asset replacement is a framework to ensure the road to a modern grid only needs to be paved once and that modern grid investments are planned, targeted, and coordinated.

7.2 TRANSMISSION

The transition of the Companies' grid from its current state to the future vision described in this report will entail substantial changes at the bulk system level. The Companies identify this need as an overall approach to grid modernization, and the related technologies and action plans are extensively discussed within the December 2016 PSIP.

Alternatives to traditional system stability approaches are needed that utilize advanced technologies

Operational resiliency and reliability (or system security), is the ability of the electric system to withstand disturbances such as electric short-circuit faults or the unanticipated loss of system components. Frequency support is required to stabilize frequency on the synchronized grid and to maintain continuous balancing of generation resources and customer load by deploying

automatic generation response functions in response to frequency deviations. Under pre- and post-contingency conditions, system operators must have the ability to raise or lower generation (or load) either automatically or manually. Voltage support and short-circuit availability is also required to maintain system-level voltages on the grid within established limits to prevent voltage collapse, system instability, or delayed fault clearing.

The Companies plan to integrate large quantities of variable wind and solar into the island grids, displacing traditional conventional central station generation. However, the de-committing of conventional generation also results in the system loss of voltage control, short-circuit availability, inertia, and primary frequency response services. Because conventional generators historically provided these grid services for system security, replacing these services with multiple assets will require innovative planning and operations.

The deployment of autonomous resources like IEEE 1547-compliant advanced inverters, with settings appropriate for Hawai`i, which are not directly controlled by the utility can potentially help balance the grid, while not compromising system security. Some of the Companies' technical strategies for operating reliability are outlined in Table 7.

Table 7 Strategies for Maintaining Operating Reliability

Issue	Current Methods	Future Methods
Frequency Support	Inertia is the stored rotating energy in a power system provided by online synchronous and induction generation operating at least their minimum power output level. Primary frequency response (droop) is the automatic corrective response of the system, typically provided by synchronous generation, to react or respond to a change in system frequency. Spinning reserve is typically provided by synchronous generation that is ready to ramp up or down in response to a frequency deviation. Demand response is the reduction of load to balance loss of generation triggered at a predetermined frequency set point and limited by program participants. Under-frequency load shed scheme is the automatic disconnection of blocks of load to rebalance the system during a frequency disturbance.	Synchronous condensers and flywheels to provide inertia. Fast frequency response resources such as batteries, flywheels, curtailed PV, and wind energy that can respond in cycles, upwards, by injecting energy into the grid. Demand response resources (with fast frequency response characteristics) that can respond within a specified time adequate to correct frequency imbalances. This can include reductions in load or injection of real power from DER aggregated into a controllable and quantifiable program to respond to under-frequency events, or a fast injection of controllable load in response to an over-frequency event. Autonomous downward response of inverter-based DER resources configured with the advanced inverter frequency-watt function to respond to an over-frequency event.

Issue	Current Methods	Future Methods
Voltage Support/Short-Circuit Availability	Reactive power supply and voltage control provided by synchronous generating facilities, excitation systems, and capacitors. Protective relay schemes designed to isolate faults within cycles. Fault current supplied by synchronous generators. Dynamic reactive power capability of synchronous generators and static var compensators.	Synchronous condensers to provide reactive power support and short-circuit current. Repurposing deactivated generators as condensers. Storage systems such as battery storage, electric vehicles, flywheels, and thermal storage to provide quick and flexible energy sources to stabilize system balancing.

The Companies understand that investment in all of these technologies, systems, and solutions cannot occur concurrently, nor are they needed at all points in the grid at this time. Therefore, this strategy calls for an integrated grid-planning process to 1) identify the technologies and solutions to address specific issues being encountered on the distribution grid and 2) coordinate aging infrastructure replacement to utilize equipment compatible with grid modernization efforts. Foundational investments in a DMS and the enabling telecommunications (discussed in Section 7.5) will be approached to enable expansion of both capabilities and performance over time with prioritized deployment of field devices and system functionality.

7.3 DISTRIBUTION

Modernizing the distribution system involves transitioning from the traditional analog, mechanical devices to digital, automated and communicating systems. This evolution is underway as described in Section 5 regarding operational systems and sensing, for example. Several additional key technologies are needed in the near-term to advance the distribution grid for our customers' needs and benefit. This includes expanding operational controls and situational awareness as described in Section 8. In this subsection, several other key technologies highlight the structural changes needed to move from a 1960s era grid toward an intelligent, automated distribution system. This includes distribution substation automation, distribution field automation and integrated volt-var management.

7.3.1 Distribution Substation Automation

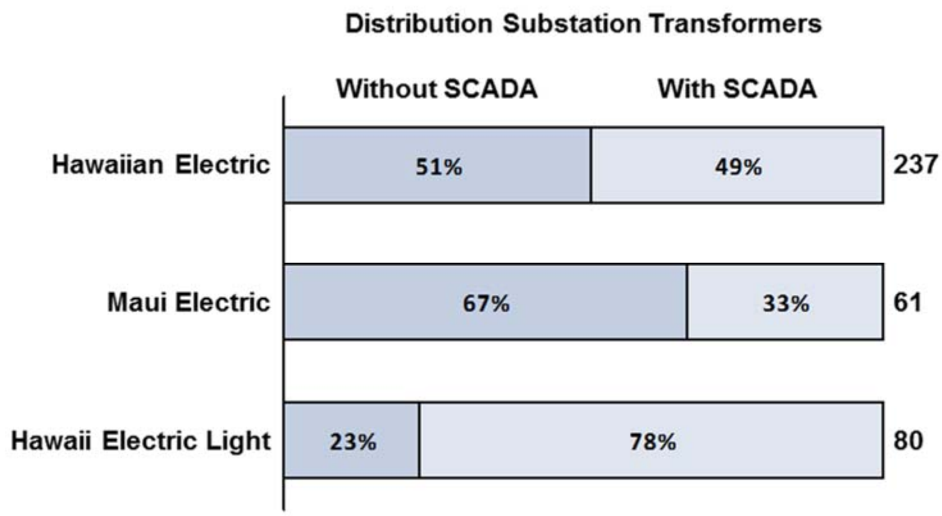
SCADA deployment at distribution substations is often seen by utilities as a fundamental and integral component to grid modernization strategies, and this is especially true in Hawai`i. The insight provided by SCADA systems is a good first step toward improved situational awareness

and automated controls to address reliability, resiliency, and operational flexibility. For example, SCADA is used to remotely control circuit breakers at substations to reduce outage duration and improve operational efficiency. Also, SCADA information is used to validate the power information across individual feeders.

The Companies have installed SCADA to both power plants and transmission substations with data transport provided by the Companies' telecommunications systems utilizing company-owned fiber, microwave, or other wireless solutions. With the increased activity on the distribution system today, the Companies must continue implementing SCADA to the distribution system for improved operational efficiency through situational awareness.

The Companies have implemented distribution SCADA (DSCADA) at many distribution substations, as detailed in Figure 16.

Figure 16 Current Status of the Companies' Distribution SCADA Deployment[91]



However, DSCADA upgrades can be challenging, given that wide-area network (WAN) communications are required to provide the connectivity between the operational center and the distribution substations. For context, the Companies' existing WAN telecommunications systems utilize company-owned fiber, microwave, or other wireless solutions. Future DSCADA projects must also consider the enabling telecommunication infrastructure approach, as discussed further in Section 7.5.

The Companies will prioritize which distribution substations should be upgraded using the proposed proportional approach, which considers the relative contributions of DSCADA toward customer reliability expectations and the goal of incorporating more renewable

[91] Hawaiian Electric and Maui Electric MECO data pulled from DASIP Final Report – October, 2015. Hawaii Electric Light HELCO data consistent with DASIP and interview with system operations.

generation. Deployment and implementation of automation may proceed based on prioritized substation classes; however, individual substations may be reclassified as the impact of renewables, reliability, and the customer load mix change priorities over time. Regardless of individual business drivers, deployment and implementation of automation is ideally prioritized at individual substations, where the greatest anticipated utility and customer benefits may be realized. Distribution substations, where automation provides the fewest anticipated utility and customer benefits, may be deferred as a lower priority or not automated at all.

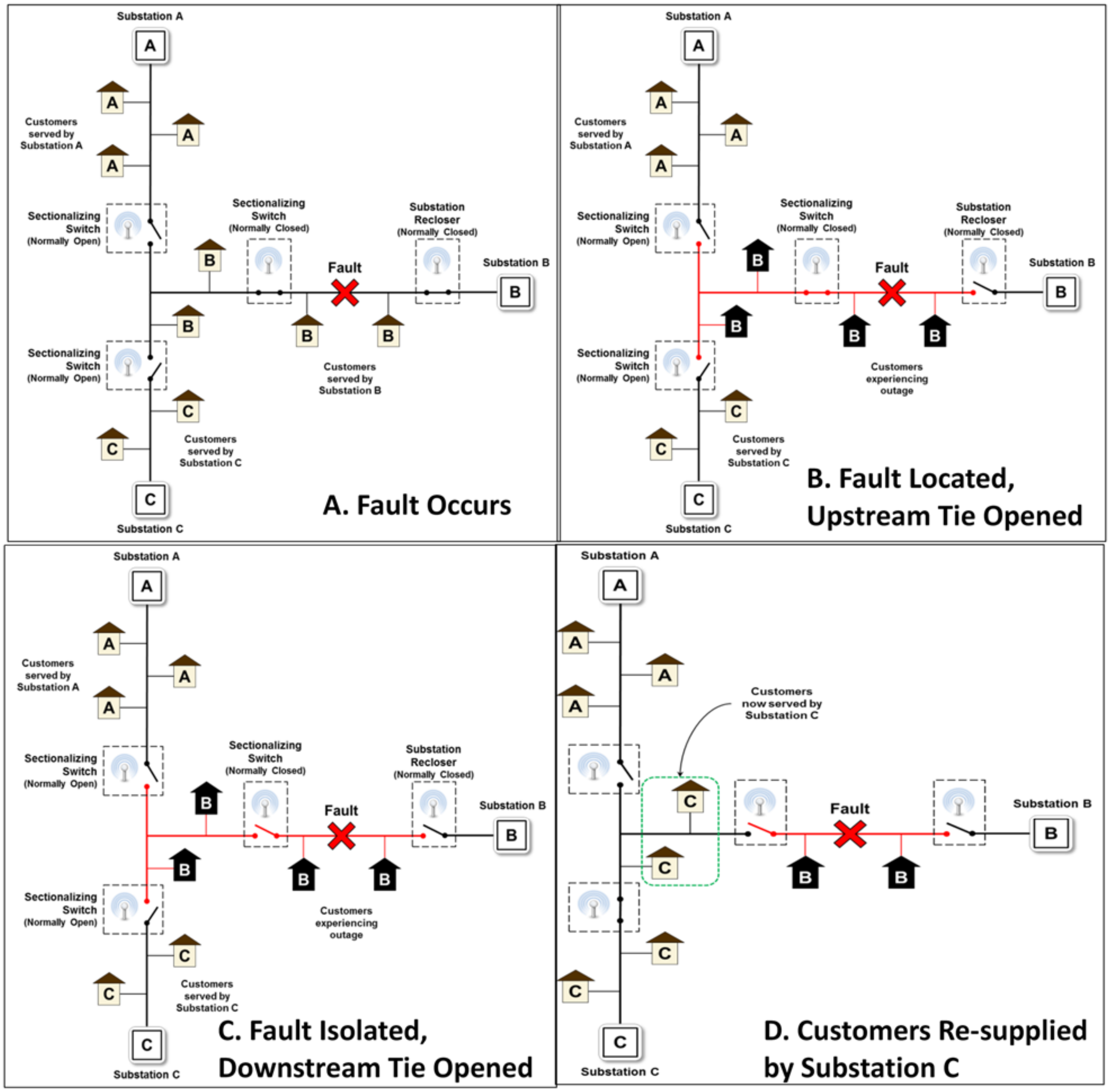
7.3.2 Distribution Field Automation

For example, the Companies' adoption of first generation automation and fault identification has been effective for one-way power flow. But, a new generation of distribution field automation technology will substantially improve customers' service reliability and provide more efficient grid operations.

The specific difference in the existing technology deployed in the Companies' distribution system and the new generation is the level of digital automation, sensing, measurement, and communications capability. For example, one key new component is an intelligent recloser switch (recloser) for distributed field automation. Reclosers with overcurrent protection have the ability to open and interrupt a fault before the circuit breaker operates, then after a short delay, close automatically to re-energize the power line. This reduces the number of customers impacted - especially since these types of reclosers are typically installed at the mid-point of a circuit. Grid operations are made more efficient by pairing an intelligent recloser with automated switches on ties to adjacent feeders. This enables the feeder to automatically bisect and restore service to the unaffected half by switching the customers and associated DER to the adjacent circuit as illustrated in Figure 17 from DOE[92].

[92] DOE, Distribution Automation: Results From the Smart Grid Investment Grant Program, September 2016

Figure 17 Reclosers and Sectionalizing Switch Operation



Intelligent reclosers are sophisticated and include power measurement capabilities in addition to fault detection and peer to peer communications. The measurement capabilities include voltage, current, power factor, and other important measurements, for an increasingly dynamic system. Intelligent advanced reclosers linked to a field communications network with operational controls and analytics to improve reliability is considered leading practice in the industry.

Intelligent reclosers also benefit DER when integrated into a revised grid architecture and can improve the availability and power production of distributed resources. These changes are achieved by improving the uptime of distribution systems and thereby increasing the time

DERs are available to produce power. This is critical as the distribution system is increasingly being used as a means to connect, in the aggregate, a large portion of the generation portfolio to the transmission system. For these reasons, distribution field automation is identified as a foundational component to transform the distribution system from a one-way to a bi-directional system.[18]

These automated field devices can provide additional operational flexibility by reconfiguring circuits to maintain DER production and optimally leverage existing infrastructure. For example, consider a circuit segment that is heavily loaded and has PV generation that exceeds its load. This segment is normally connected to a circuit with light loading but high PV generation, but it also has a tie point to a heavily loaded circuit with low PV generation. Using automated devices, this segment could be switched to the heavily loaded circuit with low PV during peak solar production hours and then reconnected to the lightly loaded circuit at other times. This command could be sent manually via SCADA or autonomously via a DMS. Implementing this scheme with advanced automation devices helps maximize the DER utilization. In the near term, these devices benefit the most problematic circuits in terms of their reliability, as well as benefitting those circuits with significant DER adoption.

In addition to direct reliability improvement benefits to customers, this automation also can reduce the operational expense of field personnel related to faster identification, isolation and restoration of outages. The results of this analysis are consistent with the DOE's findings in its post-Smart Grid Investment Grant (SGIG) report on distribution automation deployments under the program. [93,94,95]

As such, the strategy going forward is to selectively deploy midpoint automated reclosers on the most problematic circuits (primarily overhead) as identified in the proposed integrated grid planning process. Additional devices are especially useful if a normally open tie point to another circuit is available, because the fault can be isolated in smaller segments, allowing more customers and DER to have power restored from the alternate circuit. Older reclosers may be replaced with advanced reclosers as more demanding operational situations require. Additionally, automated reclosers will be selectively deployed on those circuits with high concentration of DER to improve reliability and operational flexibility to improve the availability of DER where cost-effective.

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[93] American Recovery and Reinvestment Act of 2009, Reliability Improvements from the Application of Distribution Automation Technologies, Smart Grid Investment Grant Program, December 2012: https://www.smartgrid.gov/files/Distribution_Reliability_Report_-_Final.pdf

[94] American Recovery and Reinvestment Act of 2009, Smart Grid Investments Improve Grid Reliability, Resilience and Storm Responses, Smart Grid Investment Grant Program, November 2014: http://energy.gov/oe/downloads/smart-grid-investments-improve-grid-reliability-resilience-and-storm-responses-november

[95] American Recovery and Reinvestment Act of 2009, Fault Location, Isolation, and Service Restoration Technologies Reduce Outage Impact and Duration, Smart Grid Investment Grant Program, December 2014: https://www.smartgrid.gov/files/B5_draft_report-12-18-2014.pdf

7.3.3 Integrated Volt-var Management

Power quality is an important dimension of service for customers. The Companies have an objective responsibility to ensure that electricity is delivered with power quality[96] that is within established service limits for the customer. One of the key elements of power quality is to manage the steady-state and transient voltage at the customer consistent with the Companies Tariff Rule No. 2 (Character of Service), which is similar to ANSI C84.1.[97] Voltage variations on circuits with high DG-PV adoption, especially on the secondary side of the circuit, are a significant existing and growing issue.

Voltage management involves coordinated control of both real (watt) and reactive power (var) either with grid-side equipment and or customer devices such as inverters associated with DG-PV and battery energy storage. Traditional voltage management methods continue to be effective solutions, but they are not always the most cost-effective means. Innovation in advanced power electronics have resulted in customer advanced inverters and grid-connected var controllers, described in Section 5.2.3.1 as "SVCs". These advanced power electronic devices, when integrated as part of a holistic distribution voltage system, can cost-effectively manage steady-state and transient voltage issues that arise from increased customer adoption of dynamic distributed energy resources, such as DG-PV.

The Companies are pursuing a strategy that leverages the innovation in power electronics with existing voltage management equipment and incremental traditional techniques, as needed, to satisfy power quality requirements and improve hosting capacity to enable customer adoption of DER. The SVC technology has the potential to increase the hosting capacity of existing circuits in the range of at least 5 percent up to 40percent, based on the recently completed pilot project noted in Section 5.2.3.1. The following discussion outlines the elements of this strategy.

Integrated Voltage Management Strategy

Given the results of the Companies' study of advanced inverter grid support with the National Renewable Energy Laboratory (NREL),[98] various pilots, and experience to date, the Companies believe the following approach will address customers' service quality requirements and improve hosting capacity most cost-effectively.

First, where possible:

- Seek to align aging infrastructure replacement with areas of DER growth to enhance hosting capacity in addition to the inherent reliability improvements,

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[96] Power quality includes steady-state voltage levels, as well as flicker, harmonics, and transients (rapid single events)

[97] American National Standard for Electric Power Systems and Equipment—Voltage Ratings (60 Hz): https://www.nema.org/Standards/Pages/American-National-Standard-for-Electric-Power-Systems-and-Equipment-Voltage-Ratings.aspx

[98] NREL Hawaiian Electric Advanced Inverter Grid Support Function Laboratory Validation and Analysis, December 2016: http://www.nrel.gov/docs/fy17osti/67485.pdf

- Leverage the autonomous functionality of advanced inverters to mitigate voltage issues and those that may otherwise arise from increased DG-PV adoption, especially on the secondary side of the distribution circuit. This may involve customized settings for different distribution circuits, or locations on a distribution circuit, improving the coordinated benefits of the overall voltage management system, and
- Exhaust all low-cost options to modify existing infrastructure. For example, adjustments of load tap changer settings, including load drop compensation, or phase balancing, can be completed on all circuits that are already equipped with sensing equipment and have actual field data. Sensing equipment should therefore be added to circuits without monitoring capabilities that are nearing their hosting capacity.

Second, when DER used as supply resources reach 100 percent of the circuit hosting capacity, SVCs will be used to augment the autonomous advanced inverter functionality. For those circuits or sections with insufficient customer advanced inverters installed/upgraded, then SVCs will be cost-effectively employed as needed to address voltage quality issues.

The SVC solution is a device connected to the secondary side of a pole- or pad-mounted service transformer that can inject vars and can regulate the voltage tightly (± 0.5% within control range) locally and/or feeder-wide. The devices are autonomously controlled once a set-point is dispatched via the utility DMS system or SCADA. The assumption is that SVCs will be deployed at locations identified based on existing or anticipated voltage issues in a just-in-time solution deployment.

Third, if the above measures or other low-cost mitigations are not sufficient to address the identified service quality need on selected circuits or sections, then traditional upgrades will be employed, such as reconductoring and replacing transformers, to reinforce the distribution circuit.

Additional Considerations

The Challenges of Advanced Inverter Implementation

Although Hawai`i interconnection standards require certain advanced functionality from inverters installed after January 1, 2016,[99] it will take some time for customers working with their inverter suppliers to upgrade their inverters. This may create some uncertainty on how best to address identified voltage quality issues on certain circuits or sections during this transitional phase. The Companies recognize the contribution that advanced inverters may make, but they also note that customers are clearly expecting high service quality and reliability that may necessitate alternatives if the implementation of advanced inverters is slow or stalled.

[99] Hawaiian Electric Companies - Standard Interconnection Agreement: https://www.hawaiianelectric.com/clean-energy-hawaii/producing-clean-energy/standard-interconnection

The Companies also anticipate that it may be useful to periodically send coordination set-point changes to advanced inverters. This is expected to be done through messaging with the inverter manufacturer and/or inverter aggregator's back-end systems as opposed to the Companies directly communicating with the customer's inverter. This approach simplifies the interface and systems needed. However, if this proves to be unworkable should inverter manufacturers or aggregators be unable to reliably access customers' inverters, then it may be necessary to consider a direct communication link to the inverter.

This creates two potential issues. One, there are at least four options (recognized by IEEE[100]) for advanced inverter communications. This creates challenges for an aggregator to provide interoperability between these various communications systems. Additionally, the use of a standard protocol or specification (such as SunSpec[101]) will be needed. However, as with many industry standards, manufacturer implementation is often incomplete or a key portion is crafted in a proprietary manner which complicates the ability to communicate and control products from different manufacturers.

Advanced Inverter Integration with Voltage Management Applications

Integrated volt-var control (IVVC) systems that coordinate the various grid-side pieces of equipment with advanced inverters are in their infancy, with limited capabilities currently available. These IVVC systems, thus far, have often been developed completely independently for each project or utility customer. In some cases, this functionality is incorporated into DERMS, in other cases as a module associated with a DMS to create an advanced distribution management system (ADMS). The Companies are working with vendors to explore this development. In the near term, this does not impede the Companies' strategy as described above.

7.4 DER MANAGEMENT

The Demand Response Management System (DRMS)[102] project involves the purchase, installation, and configuration of the software platform that is a prerequisite for the successful implementation of the IDRPP across all three Companies. Installation of a DRMS will allow the Companies to manage DR resources and other DER through a single integrated system.[103,104]

[100] IEEE Advanced inverter functions and communication protocols for distribution management: http://ieeexplore.ieee.org/document/7520035/

[101] SunSpec Alliance: http://sunspec.org/

[102] HPUC Docket No. 2015-0411, Application for Approval to Defer Certain Computer Software Development Costs for a Demand Response Management System (DRMS).

[103] The term "DR resources" in the PUC Docket No. 2015-0411 Application is inclusive of any customer sited DERs including but not limited to PV, distributed storage and EV

[104]

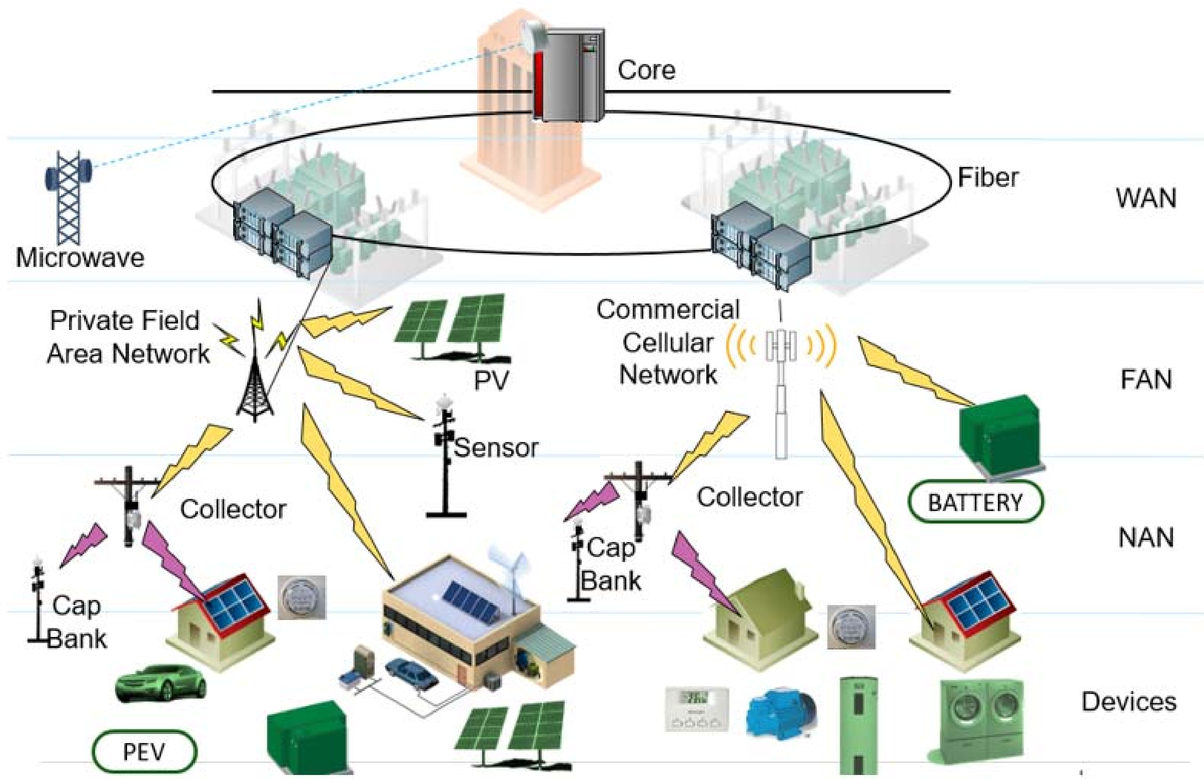
The functionality of the DRMS will evolve to a full DER management system (DERMS) to facilitate the utilization of the Companies' DR programs and aggregated DER from others to manage the power system.

7.5 TELECOMMUNICATIONS

Telecommunications are a core component in the safe, secure, reliable, and efficient operation of a modern electric system.[18] Utility communications networks are typically deployed in a layered (tiered) manner, as illustrated in Figure 18. At the highest level, the operations center, power plants, substations, and data centers are interconnected with a wide-area network (WAN). The next layer down is a field-area network (FAN), which communicates between distribution substations and field devices, such as field communication routers, which link to a neighborhood-area network (NAN), which connects reclosers, switches, capacitor banks, advanced meters, and utility-managed demand response devices, such as water heaters and A/C cycling devices.

HPUC Docket 2015-0412, Application for Approval of Demand Response Program Portfolio Tariff Structure.

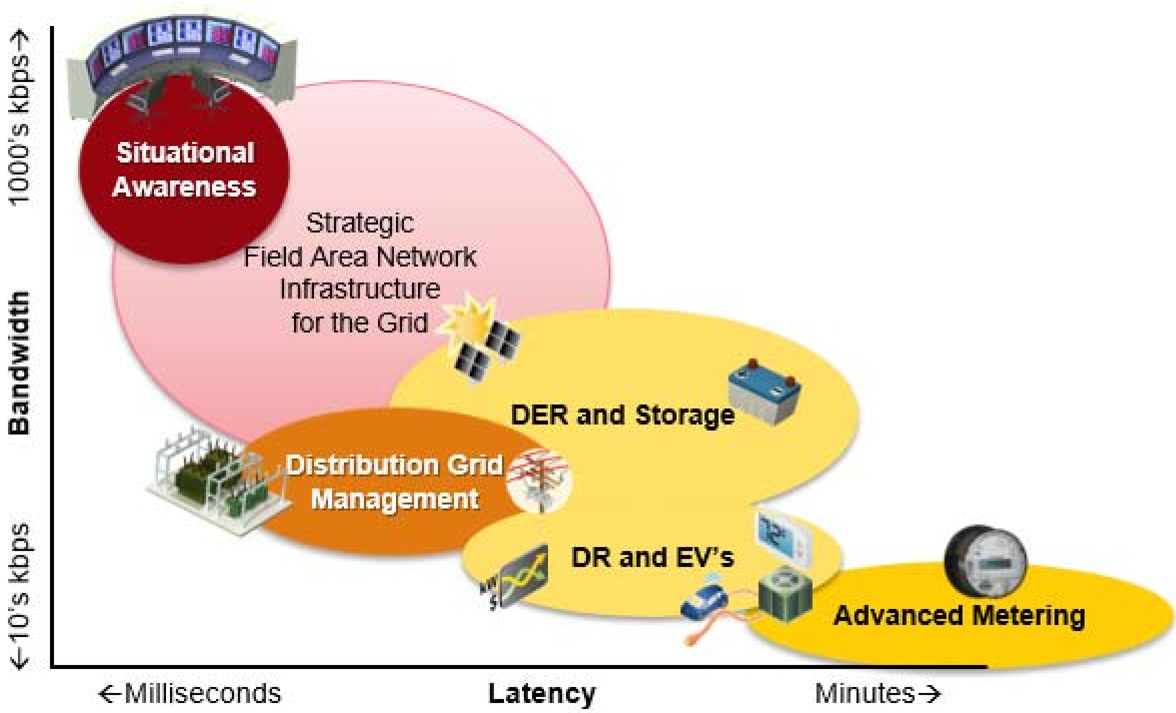
Figure 18 Tiered Utility Communication Network Structure



The architectural requirements for the communications solution may be categorized into two broad types; hierarchical and peer-to-peer. The first refers to communication traffic flows between a centralized control center and grid assets located in the field. The peer-to-peer communication flows are a newer and emerging requirement to support modern grid functions to enhance reliability and DER integration and utilization. This capability also enables applications such as microgrids and islanding. In this case, the communicating devices located in the distribution grid, and at the grid edge, directly pass communications traffic without the flow routing through the central operating systems.

Bandwidth requirements, which are specified in terms of data rate (kilobits per second, or kbps) and latency requirements, which is the time required for a message to traverse the network, vary widely depending on the application and the device that originates the communication. Figure 19 shows a range of latency and bandwidth requirements for a number of applications and device types.

Figure 19 Bandwidth and Latency Requirements



In general, each tier of the modern electric grid communications network requires pervasive data communications at higher data rates and lower latencies than utility communications networks have provided in the past.

7.5.1 Legacy Telecommunications Infrastructure

All of the Companies' power generation stations and transmission substations and approximately 53 percent of the distribution substations are connected using a variety of solutions for the WAN, mainly consisting of fiber optic,[105] point-to-point (PtP) microwave radio, point-to–multi-point (PtMP) wireless, leased wired, and commercial cellular data modems.

For the FAN, the Companies have historically deployed single-purpose telecommunications systems using various leased, wired, and wireless technology solutions to support the limited number of applications that require communications. Over the past few years, the number of applications requiring communications, and the associated single-purpose telecom systems, has grown dramatically. It has become increasingly challenging to manage this growing number of disparate telecom systems and maintain a reliable, robust, and secure network.

[105] The use of dark fiber on the Island of Hawai`i is assumed to be included in the definition of the Companies' private network.

NAN peer-to-peer communications among distribution assets does not currently exist.

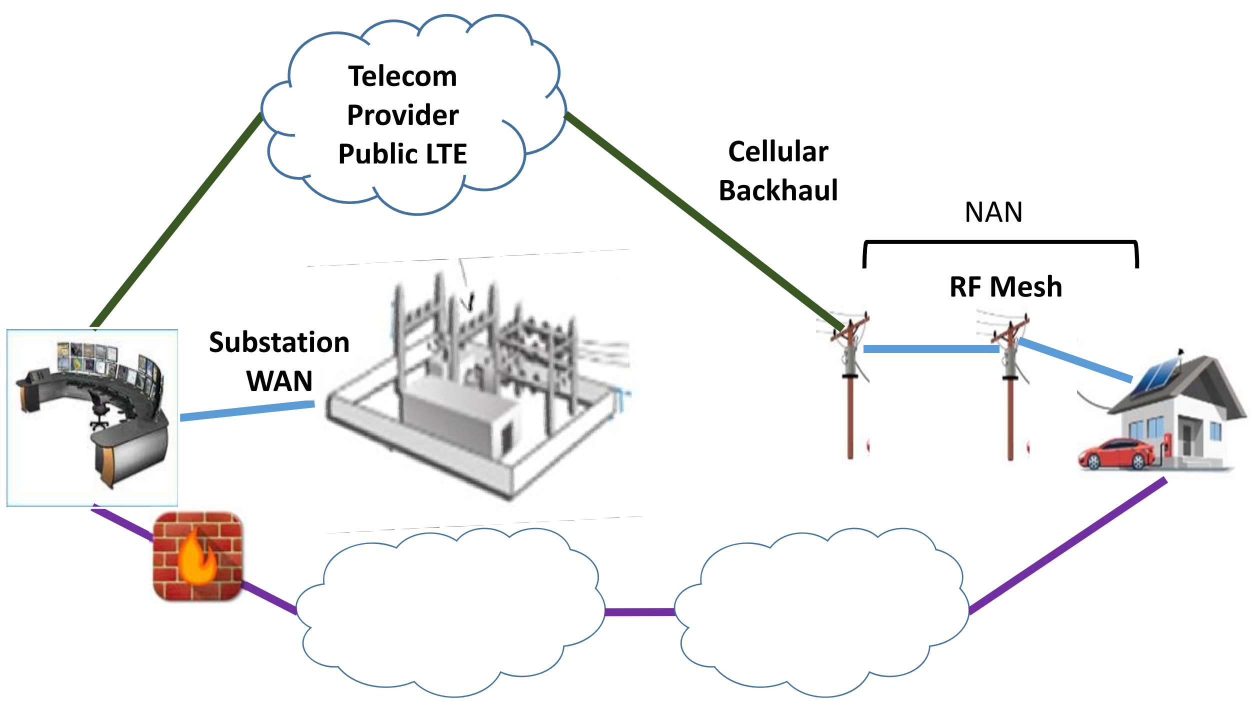
7.5.2 Strategic Approach for Building Out the Telecommunications Infrastructure

The Companies' proposed grid modernization strategy approach for telecommunications incorporates flexibility with a logical progression of targeted deployment based on grid and customer needs. The Companies' strategic approach to utility communications takes a two-step approach.

The telecommunications strategy incorporates flexibility with a logical progression of targeted deployment based on grid and customer needs.

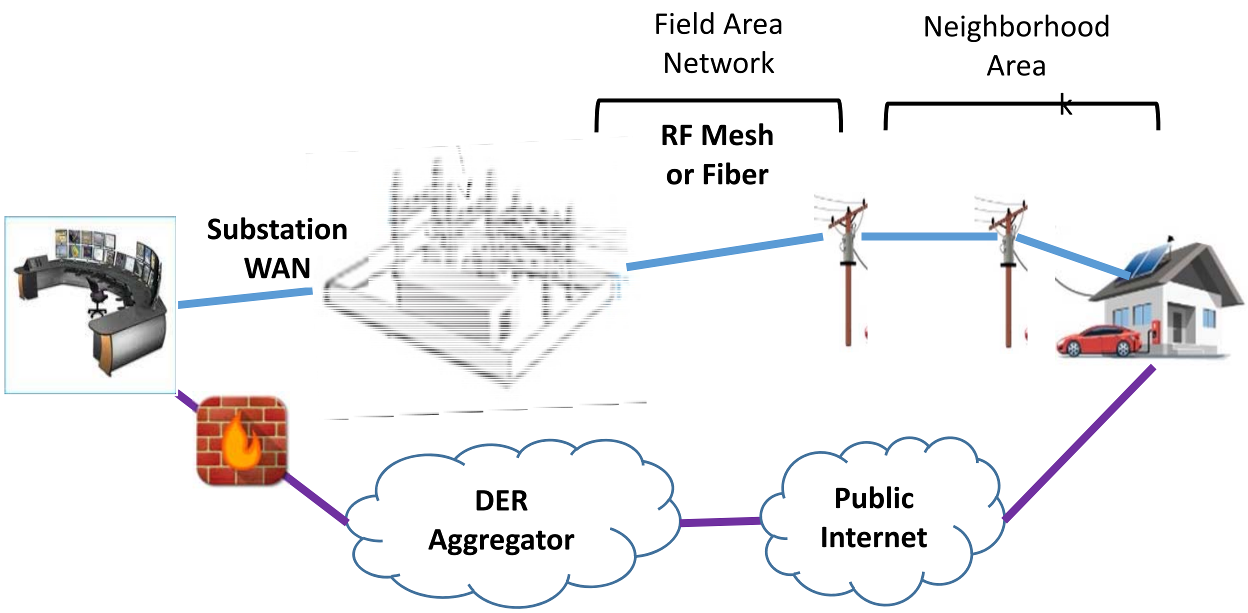
Step 1 utilizes a multi-purpose radio frequency (RF) mesh NAN that is capable of peer-to-peer traffic and leverages an open standard such a Wi-SUN to link communicating field devices such as reclosers and advanced meters, as shown in Figure 20. With a mesh network, each device or node on the network is capable of relaying the data from any other node on the network. The data is then relayed from node to node until the data reaches a data collector, which then utilizes a cellular communications backhaul to send the data to the utility back-office systems. Additionally, substation WAN deployment would be expanded to incorporate prioritized distribution substations and would use leased wire line. Third party aggregated DER would utilize their own systems, which typically leverages the Internet from customers' premises and the customers' Wi-Fi or Ethernet communications to the DER.

Figure 20 Hybrid Mesh to Cellular FAN and Substation WAN



Step 2 replaces the cellular backhaul with a FAN connection between the substations' WAN and the NAN, as illustrated in Figure 21. This step would increase the telecommunication bandwidth to accommodate more data transfer as more communicating devices are deployed and would also reduce latency to enable fast response.

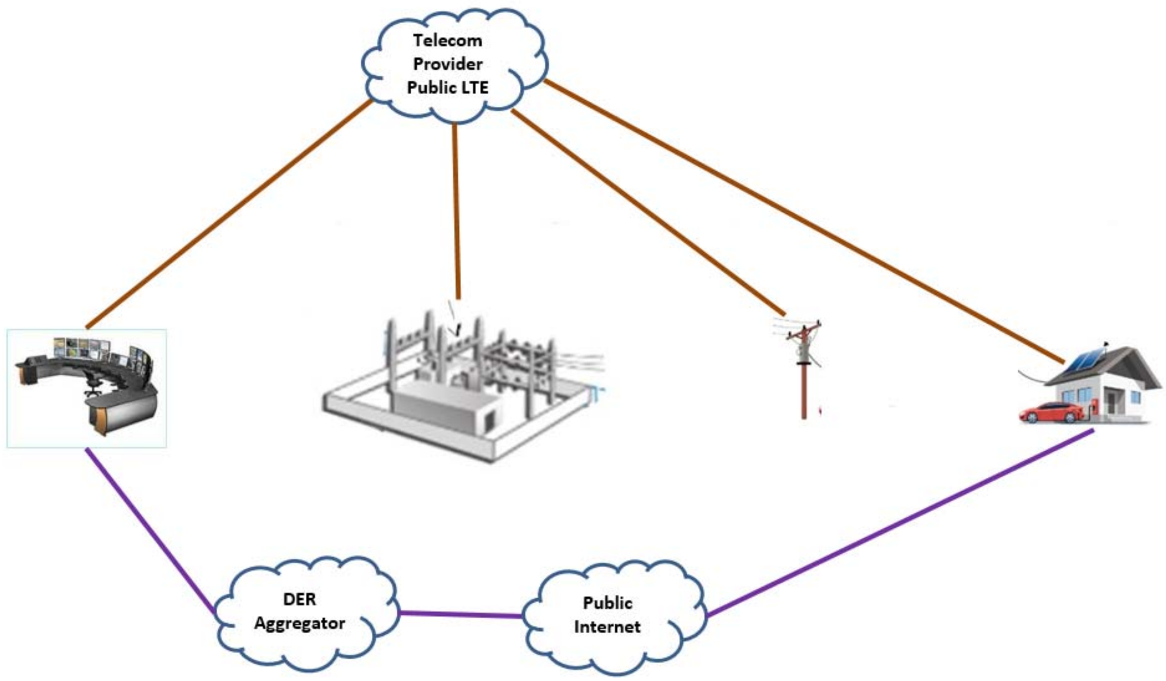
Figure 21 Leveraging Substation WAN for FAN and FAN Backhaul



Cellular Communications Option

An alternative approach for operational communications is a solution entirely based on public cellular communications as shown in Figure 22.

Figure 22 Commercial Cellular-Only Communications Approach



Cellular systems (by design) do not enable peer-to-peer communications. Peer-to-peer communications will be needed for devices on the distribution system to communicate and coordinate directly to achieve grid coordination services without the latency associated with communicating to a cellular carrier's back office.

Additionally, a cellular-based solution may not provide adequate reliability, especially during emergency conditions, when the public cellular network may become oversubscribed and unable to meet the traffic demands. The ability to provide Quality of Service (QoS) that differentiates traffic by source or content has long been a staple of the wire-line telecommunications industry but is only now developing in the commercial wireless industry. Even if QoS becomes available on cellular in the Hawaiian Islands, the issue of network hardening of the cellular infrastructure would need to be investigated. This includes items such as the duration of backup power and the wind speed for which the cellular towers are designed. These critical weaknesses were demonstrated during Hurricane Katrina and more recently during Superstorm Sandy and Hurricane Irene. Critical infrastructure industries that relied on cellular communications were left without communications for significant amounts of

time after the storms made landfall. However, for non-critical communications, such as some DA devices and DSM, the cellular solution may be adequate and economical.

7.6 CYBERSECURITY

As smarter energy infrastructure is implemented with increasing connectivity and information flow internally and with others externally, this also increases the attack surface for any potential adversary. Recognizing this, our modernization strategy addresses the need to enhance and extend cyber defenses, and evolve into a proactive deterrence rather than the traditional reactive defense.

7.6.1 Grid-Side Cybersecurity

Our approach to cybersecurity is consistent with industry best practices including the National Institute of Standards and Technology's (NIST) Framework for Improving Critical Infrastructure Cybersecurity[106], DOE Energy Sector Cybersecurity Framework Implementation Guidance[107], DOE Risk Management Process[108], EPRI's Risk Management Guide[109], and the National Association of Regulatory Commissioners (NARUC) primer on cybersecurity.[110] These frameworks and others describe two fundamental aspects for securing the grid which we apply:

- Identifying the threats and developing mitigation measures, and
- Assessing the level of risk and impact and prioritizing the mitigations appropriately. That is, proportional to the cyber-threat risk.

As examples of this two-prong approach, the NIST frameworks identify five core risk mitigation functions, or stages: Identify, Protect, Detect, Respond, and Recover. The Companies continue to utilize the framework best practices and collaborate with numerous departments and agencies to strategically develop a more proactive advanced persistent threat identification process. As the grid is modernized and integrated, the increased interconnection across the organization increases the attack surface for any potential adversary. The Companies continue to utilize the framework best practices and collaborate

[106] National Institute of Standards and Technology (NIST) Framework for Improving Critical Infrastructure Cybersecurity Version 1.0, February 12, 2014: https://www.nist.gov/document-3766

[107] U.S. DOE, Energy Sector Cybersecurity Framework Implementation Guidance: https://energy.gov/oe/downloads/energy-sector-cybersecurity-framework-implementation-guidance

[108] U.S. DOE, Cybersecurity Risk Management Process (RMP): http://energy.gov/oe/services/cybersecurity/cybersecurity-risk-management-process-rmp

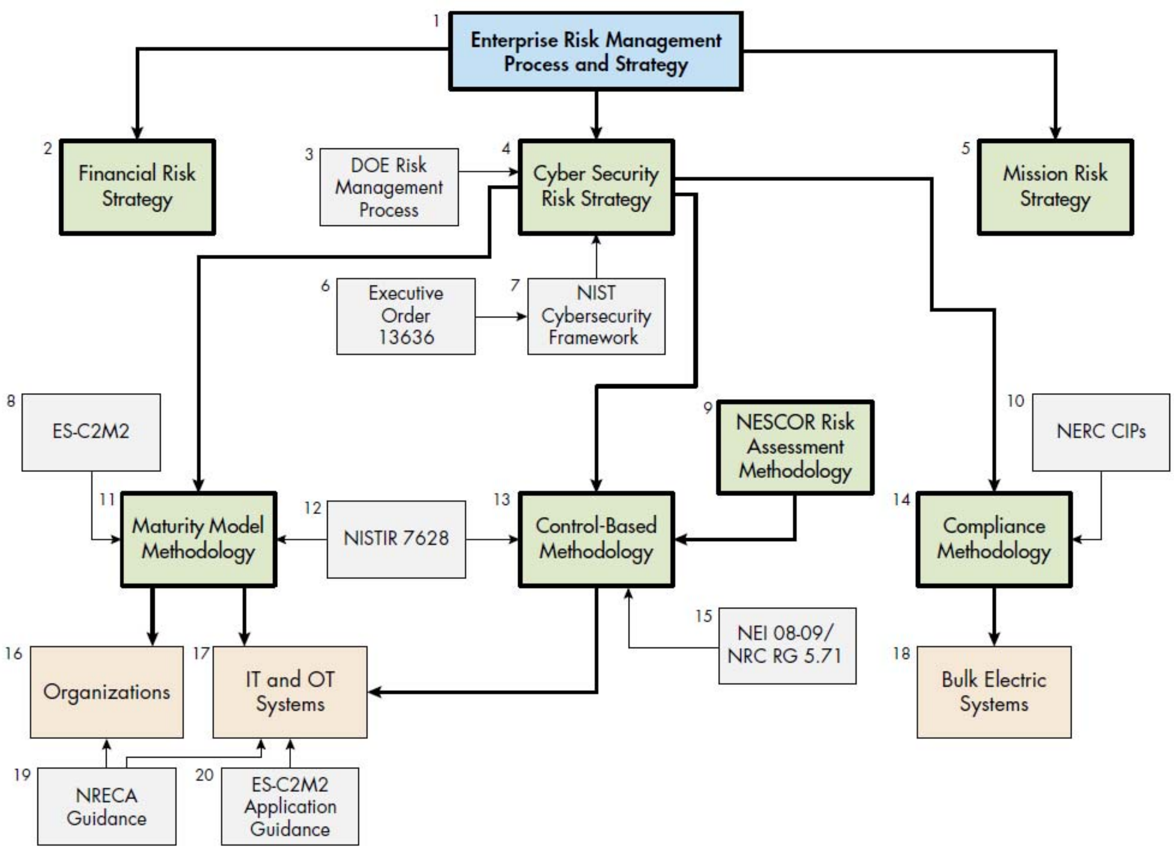
[109] Risk Management in Practice – A Guide for the Electric Sector, EPRI Technical Update, December 2014. http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002003333

[110] Keogh, M. and Thomas, S., Cybersecurity: A Primer for State Utility Regulators, Version 3.0, NARUC-DOE, January 2017 https://pubs.naruc.org/pub/66D17AE4-A46F-B543-58EF-68B04E8B180F

with numerous departments and agencies to develop a more proactive advanced threat identification process.

Together, these functions, and the tools and processes that enable each, providing a holistic "defense-in-depth" approach to secure the grid. EPRI's risk based process in Figure 23 is an example of a holistic risk management process to develop a cybersecurity strategic roadmap. In this figure, documents that may be used to address the risk of operational systems are noted in the gray boxes.

Figure 23 EPRI Enterprise Risk Management Process and Strategy Overview[111]



7.6.2 DER Cybersecurity[112]

Cybersecurity is increasingly recognized as an important consideration for interconnecting DER. This is particularly true for the aggregation of inverters. Cybersecurity requirements are

[111] From Research to Action: How to Navigate Existing Cyber Security Risk Management Guidance, http://www.electricenergyonline.com/show_article.php?mag=103&article=840

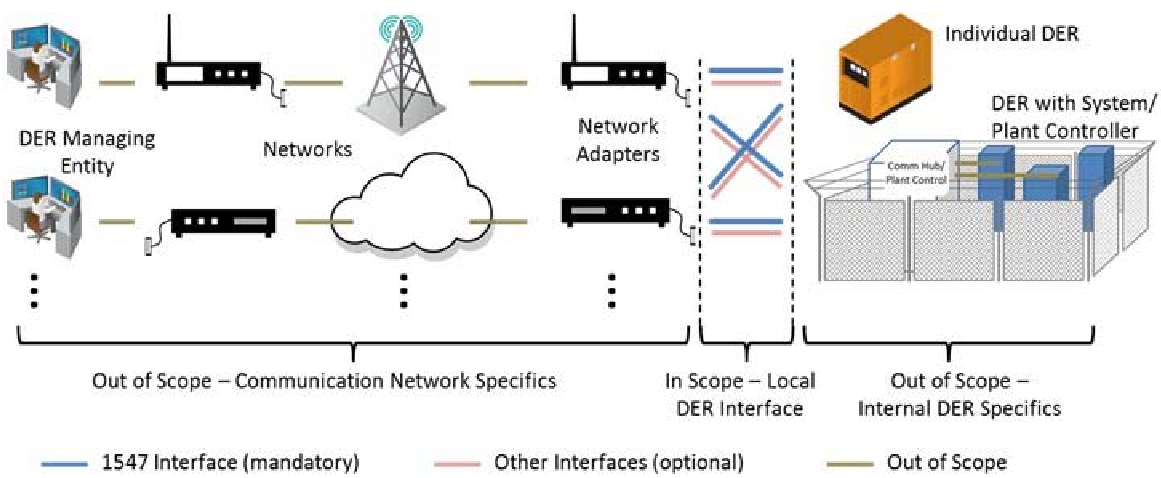
[112] Subsection material adapted from DOE, Modern Distribution Grid Report: Volume III, 2017

as essential for DER service providers and device manufacturers as they are for utilities and independent power producers. In an integrated grid, all interconnected resources are part of the cyber footprint. "Overall system security is only as strong as the weakest link – today a weak link is the integration of DER, especially those used for grid management."[113]

IEEE 1547 enables, but does not directly specify, cyber security – responsibility falls on inverter manufacturers and aggregators to establish security for aggregated devices.

In a new paper, EPRI summarizes the treatment of cybersecurity in the proposed revision to IEEE 1547.[114] In simple terms, IEEE 1547 enables, but does not directly specify, cybersecurity. Cybersecurity is expected to be addressed in the communication networks linked to DER and inverters. Communications networks and communications within the DER device itself are beyond the scope of IEEE 1547, as identified in Figure 28 below. Under IEEE 1547, cybersecurity is not mandated at the local DER interface.

Figure 28: IEEE 1547™ Scope of Communication Applicability



The IEEE working group believed the risk associated with onsite manipulation of an individual DER through its communication interface is only equivalent to the risk that exists if physical access is gained (e.g., through the keypad or disconnect switches). Because only one DER is involved in such cases, impact on power quality and grid reliability is limited. However, this is a very narrow perspective, as most advanced inverters are expected in practice to have one or more points of aggregation. One point of aggregation is the interface that the inverter manufacturers are expected to maintain to monitor performance and provide software

[113] DOE Modern Distribution Grid Report, Volume III, 2017

[114] EPRI, IEEE Standard 1547—Communications and Interoperability, 2017

updates to each inverter. A second interface is with DER aggregators that control the inverter/DER for critical grid services. A breach at a single device could be exploited to compromise an entire manufacturer's and/or aggregator's inverters/DER.

An attack on multiple inverters or DERs through a compromised network could occur either top-down from the controlling system or bottom-up through a compromised device working back up into an aggregated system. Such an attack on the aggregated devices could have very large consequences for the power system and customers. As highlighted by Sandia National Laboratory in its recent report:[115]

> "When integrated with energy demand management programs and technologies, these combined technologies significantly increase the attack surface of the national power grid and opportunity for risk to system operation from malicious actors."

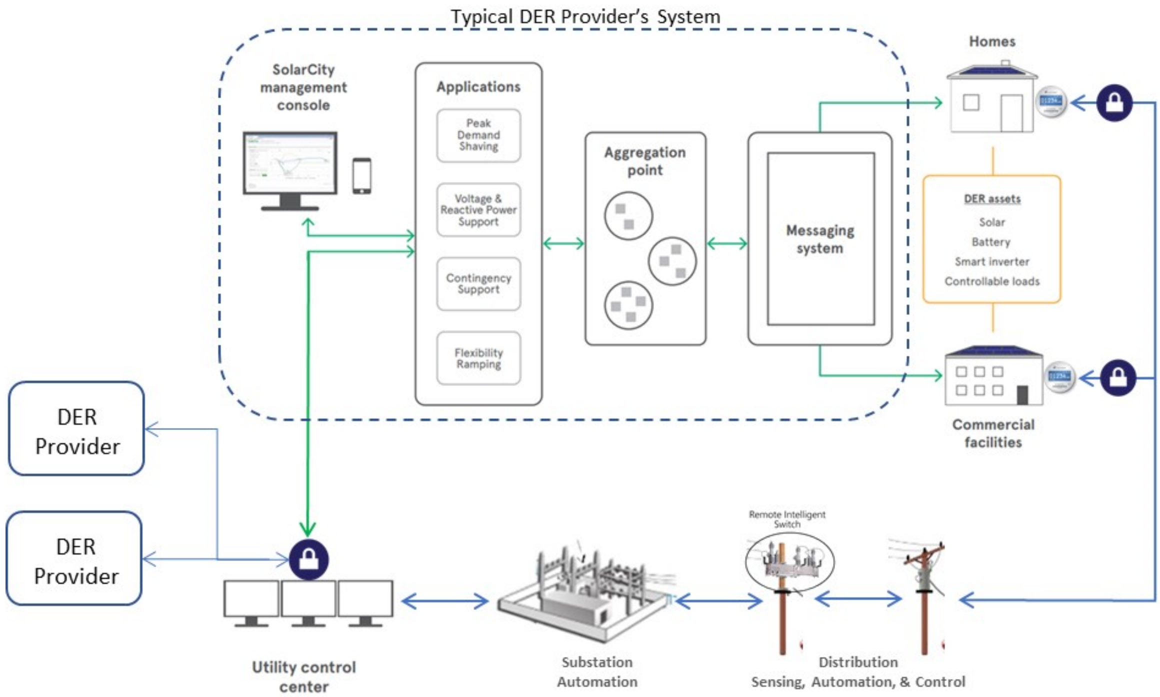
This issue already exists since some DER manufacturers and aggregators have connectivity to large numbers of devices – in some cases, a single inverter manufacturer has aggregated PV generation greater than the largest conventional generation on the grid. A DER manufacturer and aggregators investment in sensing, controls, and communications should be viewed as complementary to the utilities' investment in core cyber-physical grid platform technology. It is also important to note that many aggregators' and manufacturers' communications are typically provided over the public Internet and through a customer's Wi-Fi or wired communications. This approach to communication is wholly independent of the grid and grid devices and does not have the reliability, service quality, and cybersecurity required for critical infrastructure.

As illustrated in the diagram below, utility systems and interfaces with edge devices and aggregators are secured according to the best practices described in the NARUC Primer.[116] The same expectation is required for aggregated DER/inverters whether by manufacturers or aggregators. Today, there is no cybersecurity requirement or oversight on the aggregated DER/inverters. This is a significant gap and has very material consequences on overall electric system security as DER adoption becomes a large portion of system resources. An attack on a single manufacturer's system linked to all of its installed inverters, for example, could disconnect all inverters and create major system instability – possibly resulting in an island-wide outage. Cybersecurity standards should be established for DER/inverter managing systems and networks.

[115] Stamber, K., Kelic, A., Taylor, R., Henry, J., Stamp, J. Distributed Energy Systems: Security Implications of the Grid of the Future, Sandia National Laboratory, January 2017 Available online: http://prod.sandia.gov/techlib/access-control.cgi/2017/170794.pdf

[116] Keogh, M. and Thomas, S. Cybersecurity, a Primer for State Utility Regulators Version 3.0, NARUC-DOE. January 2017.

Figure 29: DER Aggregator & Utility Communication/Security Interfaces



Adapted from SolarCity & Joint CA Utility Presentations at CPUC Workshop on Jan 24, 2017

8 Grid Modernization Roadmap

The Companies' grid modernization roadmap is focused on maximizing customer value from advanced technology investments. This plan is based on the proportional approach discussed in Section 3, which focuses on the prioritized deployment of advanced technologies to address customer needs and value while providing flexibility to adjust to changing technology and innovation. As such, this is a least-regrets plan to develop the grid needed in Hawai`i.

8.1 NEAR-TERM ROADMAP

In this strategy, the near-term covers the period 2018 through 2023. The focus in the near term is to mitigate existing service quality issues that are arising in order to enable continuing customer adoption of DER and to create a grid platform that allows DER to become an important system resource along with centralized renewables to achieve Hawai`i's goals by 2045.

A least-regrets plan to develop the grid we need in Hawai`i at the pace of value for all customers

The sequence of technology investment enables the further development of the grid modernization capabilities that have already been deployed. The platform orientation creates a foundation that is flexible, interoperable and secure and accommodates future innovation. This roadmap also envisions a coordinated field deployment with ongoing grid asset management work to minimize the installation costs where possible. These investments are incremental and enable the utilization of DER services as non-wire alternatives. Additionally, customer-facing solutions are expanded to further engage customers to enable them to directly benefit from modernization and DER integration and utilization.

In the longer term, the strategy is to continue to evolve the grid as a platform to spur statewide economic development by enabling customer choice, state policy, electrification, and smart communities. This will involve keeping pace with changing use of the electric grid by customers and other users of the grid. The scope and timing of future investments will be informed by the integrated grid-planning process discussed in Section 4. Ongoing foundational technology investments in sensing and measurement, communications, and distribution automation will become the new business as usual and continue to be proportionally deployed based on prioritized need.

8.1.1 Customer-Facing Technologies

Customers will have several options for an advanced meter installed with the grid sensing and measurement capabilities described in Section 6.1.1. Meters will be deployed to customers opting to install distributed generation or battery energy storage or who want to participate in a responsive demand program or tariff. Meters will also be available for customers who choose to take advantage of advanced meter data and capabilities to manage their electricity usage and as bellwether meters on selected circuits with potential hosting capacity issues. Additionally, they will be available for new customer service requests and as part of inventory for replacing old or failed meters as part of a transition to the new business as usual.

The initial deployment of meters will require installation of related software systems, including the head-end and meter data management system (MDMS). The Companies plan to explore using a hosted Software as a Service (SaaS) option for the head-end and MDMS at the beginning, given the relatively low meter counts, until the installation of enterprise software is more cost-effective for customers (perhaps by 2021). Customer-facing technology will be implemented concurrent with the enterprise MDMS to provide customers access to the information from advanced meters and to decision-support analytics to manage their energy bills and choices related to DER and EVs, for example.

The smart meters currently in use in the Smart Grid Foundation initial phase will continue to be used until the results of the telecommunications procurement identifies the solution for going forward. If a different communications vendor is selected that is not compatible with the current meters, they will be replaced with new, advanced meters.

8.1.2 Sensing & Measurement

Faulted current indicators will continue to be deployed based on the current strategy. All new FCIs will be communicating and compatible with the new field communications network.

Distribution transformer measurement devices will be installed on those distribution secondary systems with multiple legacy inverters and those secondary systems that have high transformer loading from DG-PV and energy storage acting as a supply resource.

Installation of advanced meter deployment and sensing devices will optimize the development of the RF mesh communications network connectivity. Concurrently, situational awareness software will be installed to analyze data for operational use. A single enterprise solution for the Companies will be used, and the option of a SaaS solution for the first few years will be evaluated until a larger number of sensing and advanced meters are deployed. Supporting IT hardware and data management will also be implemented.

8.1.3 Operational Telecommunications

The field operational communications will be selected through a competitive procurement. The Companies anticipate deployment can begin by 2019. The RF mesh network is established

through a combination of communicating devices and routers that form the RF mesh. The routers act as the interface with the commercial cellular service that will be used in the near term to backhaul the information and data. Routers will be deployed during this period, along with establishing a network operations center in 2019 to manage the deployment and ongoing operation and cybersecurity of this network.

8.1.4 Advanced Operational Systems

Distribution management systems (DMS) and enhanced outage management systems (OMS) for each of the operating companies will be installed by early 2021. Distribution operations center (DOC) technology to support grid operator utilization of the information and controls will be deployed as part of this program. Supporting IT hardware and data management will also be implemented. Customer-facing technology to enhance outage reporting and information will be implemented concurrently with the operational systems.

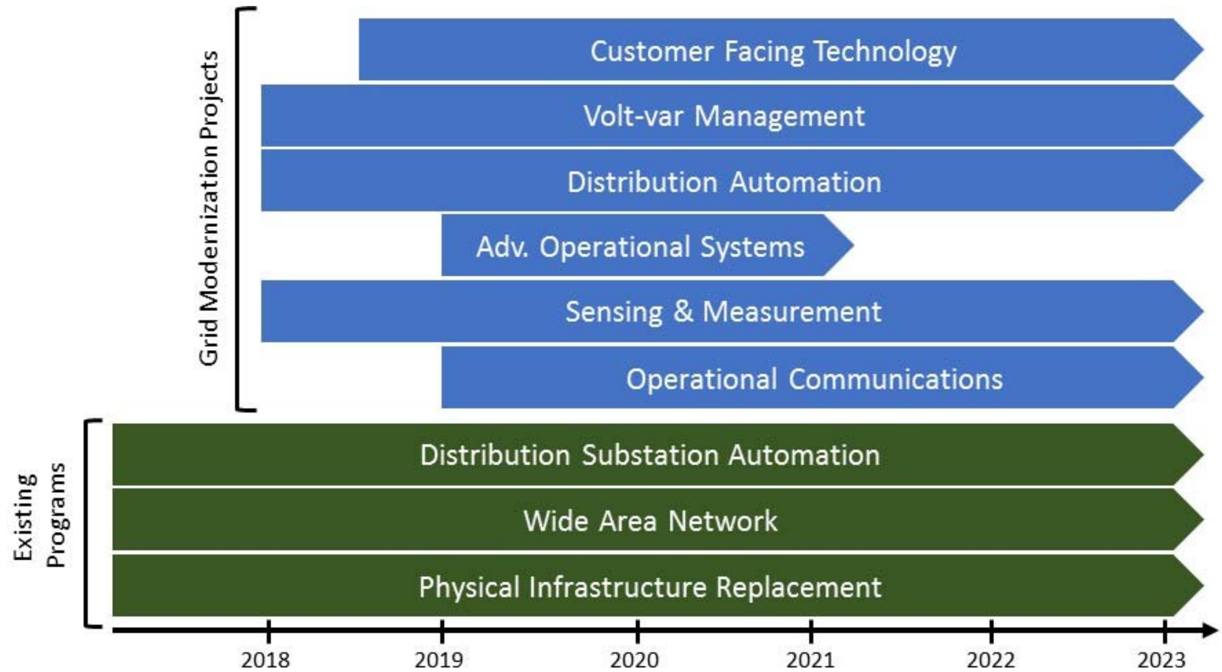
8.1.5 Distribution Automation

Intelligent "recloser" switches that communicate with the selected field communications will be deployed beginning in 2019 on the overhead distribution circuits most problematic in terms of susceptibility to outages. Also, those circuits where DER energy exports exceed the minimum load will be evaluated so that reclosers can improve operational flexibility and enhance reliability. A midpoint recloser and a back-tie switch will be installed in pairs on each identified circuit. An initial deployment in 2019 and 2020 will focus primarily on outage improvement followed in 2021 and beyond on a combination of reliability improvements and increasing operational flexibility for use of export DER.

8.1.6 Volt-var Management

Starting in 2018, secondary var controllers will be deployed on those distribution secondary systems that are experiencing voltage violations that are not first addressable through adjustment of existing load tap changers, phase re-balancing, or other lower-cost options. This is expected to involve a subset of those circuits with significant DER adoption. Advanced inverter functions may reduce the need for var controllers when autonomous inverter functions start to establish a critical mass.

Figure 24: Near-Term Grid Modernization Roadmap



8.2 CONCEPTUAL COST ESTIMATE FOR NEAR-TERM ROADMAP

Conceptual cost estimates for the grid modernization projects identified above are summarized in Table 8 below. These proposed technology costs are incremental to existing expenditures by the Companies. For instance, distributed resource management is covered by the Demand Response Management System (in Docket No. 2015-0411), and wide-area network deployment to the substation is part of an existing program to replace substation switchgears. These estimates are conceptual in nature and will be refined through project engineering, detailed requirements, and competitive procurements during the near-term period. As such, these estimates are directional only. This industry leading strategy should provide the Companies with prospects to pursue external funding opportunities.

Table 8 Conceptual Capital and Software Cost Estimate for Near-Term Investments

Investment Category (dollars in millions)	2018	2019	2020	2021	2022	2023	Total
Volt-var Management	$3.2	$3.2	$3.2	$4.3	$3.2	$3.2	$20.3
Adv. Operational Systems	-	$17.7	-	$24.4	$8.7	-	$50.8
Distribution Automation	-	$1.8	$4.8	$4.8	$4.8	$4.8	$21.0
Operational Communications	-	$0.4	$0.4	$0.4	$0.4	$0.4	$2.0
Customer Facing Technology	$1.3	$23.4	$22.8	$34.9	$8.1	$9.0	$99.5
Sensing and Measurement	$1.9	$1.9	$1.9	$1.9	$1.9	$1.9	$11.4
Annualized Total	$6.4	$48.4	$33.1	$70.7	$27.1	$19.3	$205.0
Cumulative Total	$6.4	$54.8	$87.9	$158.6	$185.7	$205.0	$205.0

8.3 ALTERNATIVES

In the December 2016 PSIP, the Companies outlined the alternatives to address DER integration and utilization at the distribution level in the December 2016 PSIP Appendix N. This comparison has been expanded to assess an enhanced business-as-usual approach (Wires) and a technology-centric approach (Grid Mod).

The Wires case assumes DER integration and utilization will continue to require distribution circuit reconductoring, service transformer replacements, and line regulators as identified in the PSIP. The Wires case, in this comparison, is enhanced with customer-facing technologies, sensing and measurement, telecommunications, distribution automation, and operational systems.

The Grid Mod case assumes that an integrated Volt-var management solution leveraging advanced inverters' autonomous functions will primarily be used to enable DER integration. Selective physical upgrades may be required if technology solutions cannot meet the engineering need. This case also includes the same customer-facing technologies, sensing and measurement, telecommunications, distribution automation, and operational systems as the Wires case.

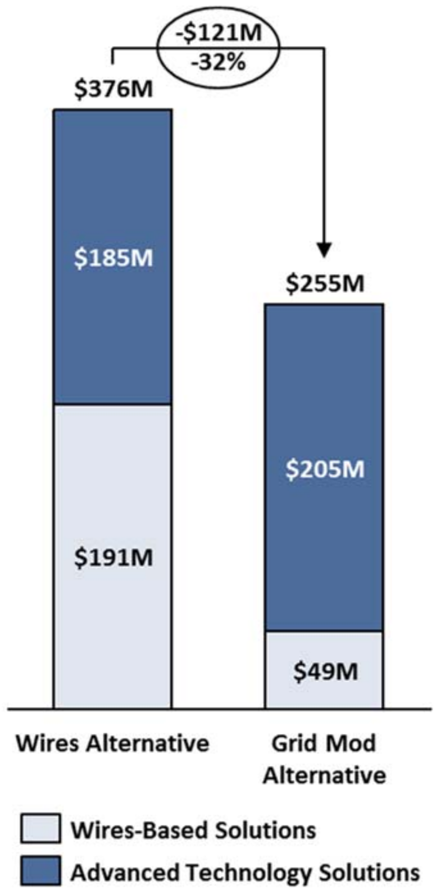
Table 9 Grid Issues With Traditional Wires and Alternative Grid Modernization Approaches

Issue	Wires	Grid Mod
Voltage Quality	Voltage regulator installation Distribution transformer and secondary conductor upgrades	Secondary var controllers, Volt-var management software Leverage advanced inverters Selective physical upgrades

Issue	Wires	Grid Mod
Customer Engagement	Advanced metering	Advanced metering
Connectivity	NAN and Cellular Backhaul	NAN and Cellular Backhaul
Situational Awareness	FCI, distribution transformer monitor equipment, situational awareness software, data management	FCI, distribution transformer monitor equipment, situational awareness software, data management
Operations Management	DMS, OMS, DOC	DMS, OMS, DOC
Operational Flexibility	Reconfigure circuit New circuit and/or substation transformer	Intelligent reclosers Selective physical upgrades

The customer benefit of a grid modernization strategy versus an enhanced business-as-usual strategy is summarized in the difference in the conceptual cost estimates for each alternative in Figure 25. This figure adapts the conceptual Wires estimate in the PSIP to that of the conceptual grid modernization estimate above aligned to the same time period. The Grid Mod alternative includes a small amount for the selective physical upgrades to create an "apples to apples" comparison. Based on this comparison, grid modernization as proposed in this strategy is more cost-effective than the Wires alternative by $121 million in the near term and more longer-term. This reduction improves the overall cost-benefit of DER for all customers.

Figure 25; Comparison of Wires and Grid Mod Alternatives (2018–2023)



8.4 NEXT STEPS

We will refocus our grid modernization program to align with this strategy.

The Companies' existing grid modernization activities will be aligned to this strategy and expanded to include the broader scope. This includes development of detailed engineering requirements, project planning, competitive technology selections, and the related cost estimates that are needed to advance applications for funding and organize a program approach to manage the execution of the near-term roadmap.

We will seek to prepare an application(s) to execute the near-term roadmap.

Most of the roadmap technology investment identified in Section 8.1 will require an application for funding. Some technologies, such as sensing, may continue under existing programs within base capital expenditures.

We will seek to initiate the integrated grid planning process in 2018.

Consistent with the discussion in Section 4, we anticipate launching the integrated grid planning process with stakeholder engagement beginning in 2018.

Appendix A: Acronyms and Glossary of Terms

An acronym list and glossary table is provided below for industry and technology terms leveraging the glossary used by the DOE DSPx effort.[117]

Table A 1 Acronym List

Acronym	Definition
ADMS	Advanced Distribution Management Systems
AMI	Advanced Metering Infrastructure
CIS	Customer Information System
DER	Distributed Energy Resources
DERMS	Distributed Energy Resource Management System
DERs	Distributed Energy Resources
DML	Daytime Minimum Load
DMS	Distribution Management System
DOE	U.S. Department Of Energy
DR	Demand Response
DRMS	Demand Response Management System
EMS	Energy Management System
EPRI	Electric Power Research Institute

[117] DOE – Office of Electricity Delivery & Energy Reliability: Next Generation Distribution System Platform (DSPx) Modern Distribution Grid, Volume 1: Customer and State Policy Driven Functionality Version 1.1 March 23, 2017 http://doe-dspx.org/wp-content/uploads/2017/03/Modern-Distribution-Grid_Volume-I_03232017v1.1.pdf

Acronym	Definition
EV	Electric Vehicle
FAN	Field Area Network
GMS	Grid Modernization Strategy
HNEI	Hawaii Natural Energy Institute
IEEE	Institute Of Electrical And Electronics Engineers
IoT	Internet Of Things
IP	Internet Protocol
IT	Information Technology
IVVC	Integrated Volt-Var Control
kW	Kilowatt
MW	Megawatt
NAN	Neighborhood Area Network
NIST	The National Institute Of Standards And Technology's
NREL	National Renewable Energy Laboratory
OMS	Outage Management System
OT	Operating Technology
P2P	Peer-To-Peer Communication
PNNL	Pacific Northwest National Lab
PtMP	Point To Multi-Point
PtP	Point To Point
QoS	Quality Of Service
RF	Radio Frequency
RFI	Request For Information
RFP	Request For Proposals
SaaS	Software As A Service

Acronym	Definition
SCADA	Supervisory Control And Data Acquisition
T&D	Transmission And Distribution
WAN	Wide Area Network

Table A 2 Glossary

Term	Description
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); demand response management system (DRMS); automated fault location, isolation, and service restoration (FLISR); conservation voltage reduction (CVR); and volt-var optimization (VVO).
Advanced Inverters	Inverters for converting between Direct Current (DC) and Alternating Current (AC) with Hawai'i specific IEEE 1547 compliant (when available) voltage control from volt-var and volt-watt functions and greater resiliency during voltage or frequency deviations with visibility into distribution system conditions via data collection. These inverters would operate autonomously.
Advanced Metering Infrastructure (AMI)	Typically refers to the full measurement and collection system that includes meters at the customer site, communication networks between the customer and a service provider, such as an electric, gas, or water utility, and head-end data reception and management systems that make the information available to the service provider. It is also referred to as an advanced meter system.
Advanced Meters	Meters capable of two-way communication, advanced power measurement, computing platform, outage and service quality information, service switch
CAIDI (Customer Average Interruption Duration Index)	If a customer experienced an outage during the year, the average length of time the customer was out of power, in hours.
Conservation Voltage Reduction (CVR)	An operating strategy of the equipment and control system used for VVO that reduces energy and peak demand by managing voltage at the lower part of the required range.
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.

Term	Description
Customer Relationship Management (CRM)	A system that provides tools for documenting and tracking all customer interactions. CRM also provides analytical tools to track and adjust marketing campaigns, forecast participation rates, and move customers from potential participants to fully engaged customers.
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.
DER Aggregator	3rd party service working with customers to aggregate 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 Energy Resources (DERs)	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.
Distribution Management System (DMS)	An operational system capable of collecting, organizing, displaying, and analyzing real-time or near real-time electric distribution system information. A DMS can also allow operators to plan and execute complex distribution system operations to increase system efficiency, optimize power flows, and prevent overloads. A DMS can interface with other operations applications, such as GIS, OMS, and Customer Information System (CIS) to create an integrated view of distribution operations.
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 SCADA (DSCADA)	The application of supervisory control and data acquisition software to the distribution grid. SCADA is defined below.

Term	Description
Distribution System	The portion of the electric system that is composed of medium voltage (69 kV to 4 kV) sub-transmission lines, substations, feeders, and related equipment that transport the electricity commodity to and from customer homes and businesses and that link customers to the high-voltage transmission system. The distribution system includes all the components of the cyber-physical distribution grid as represented by the information, telecommunication and operational technologies needed to support reliable operation (collectively the "cyber" component) integrated with the physical infrastructure comprised of transformers, wires, switches and other apparatus (the "physical" component).
Energy Management System (EMS)	
Fault Location, Isolation and Service Restoration (FLISR)	Includes the automatic sectionalizing, restoration and reconfiguration of circuits. These applications accomplish distribution automation operations by coordinating operation of field devices, software, and dedicated communications networks to automatically determine the location of a fault, and rapidly reconfigure the flow of electricity so that some or all customers can avoid experiencing outages. FLISR may also be known as Fault Detection, Isolation and Restoration (FDIR).
Faulted Current Indicators	Field devices that sense fault current to help determine the location of a fault and with communications capability.
Field Area Network	The second level of a tiered utility communications structure connecting distribution substations and field devices such as field routers
Geographic Information System (GIS)	
Global Positioning System (GPS)	A system of satellites and receivers that determines the position (latitude, longitude and altitude) of a receiver on Earth. GPS is also used as a source of precision time signals for device synchronization.
Grid Architecture	The application of system architecture, network theory, and control theory to the electric power grid.
Hawaiian Electric Companies (Companies)	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 herein as "Hawaiian Electric Companies" or "Companies".
Integrated Grid	

Term	Description
Internet of Things (IOT)	The network of physical objects (or "things") embedded with electronics, software, sensors, and connectivity that enables the object to achieve greater value and service by exchanging data with operators, aggregators and/or other connected devices. Each object has a unique identifier in its embedded computing system but can interoperate within the existing Internet infrastructure.
Internet Protocol (IP)	Packet Communication uses IP digital protocol to handle data in variable length packets that are routed digitally to their destinations asynchronously rather than making a fixed circuit connection or relying on fixed time intervals.
Inverter	A device for transitioning Direct Current (DC) to Alternating Current (AC).
Local Distribution Area (LDA)	Consists of all the distribution facilities and connected DERs and customers below a single transmission-distribution (T-D) interface on the transmission grid. Each LDA is not normally electrically connected to the facilities below another T-D interface except through the transmission grid. However, to improve reliability, open ties between substations at the distribution level exist.
MAIFI (Momentary Average Interruption Frequency Index)	The average number of outages a customer experienced during the year that are restored within five minutes.
Markets	Referred to generically in this strategy include any of three types of energy markets: wholesale power supply (including demand response), distribution services, and retail customer energy services. Markets for sourcing non-wires alternatives for distribution may employ one of three general structures: prices (e.g., spot market prices based on bid-based auctions, or tariffs with time-differentiated prices including dynamic prices); programs (e.g., for energy efficiency and demand response) or procurements (e.g., request for proposals/offers, bilateral contracts such as power purchase agreements).
Microgrid	A group of interconnected loads and DERs within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid. A microgrid can connect and disconnect from the grid to enable it to operate in both grid-connected or island modes.
Microgrid Interface	The set of power electronics at the Point Of Interconnection (POI) between the "island-able" portions of a grid, and the larger distribution grid, that support the essential microgrid functions of islanding and reconnection. The microgrid interface may also have the capability to provide services to the macro grid including volt-var control. As services are dropped from the distribution grid side of the interconnection, the microgrid interconnect disconnects, and the microgrid continues to provide service to critical loads in the islanded area.
Microwave Radio communications	High frequency radio systems that may be point-to-point or point-to-multipoint systems. They are widely used for substation and SCADA communications.

Term	Description
Neighborhood Area Network	The third level of a tiered utility communication structure that connects reclosers, switches, capacitor banks, advanced meters, and utility managed demand response devices such as A/C cycling devices.
Net Benefits	Expenditures that are not required for Standards and Safety Compliance or Policy Compliance, but would provide positive net benefits for customers.
Net Load	Net Load is the load measured at a point on the electric system resulting from gross energy consumption and production (i.e., energy generation and storage discharge). Net load is often measured at a T-D interface and at customer connections.
Optical Fiber communication systems	Optical fiber systems are capable of very high bandwidths and form the backbone of high capacity communication systems sending data via modulated light through a transparent glass or plastic fiber
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.
Peer-to-Peer Communication (P2P)	A network service or standalone capability that permits two devices to communicate with one another. As a network service, the central part of the system responds to a request by providing each device the information and resource necessary to establish direct communication. As a standalone capability, P2P becomes synonymous with point-to-point and is a dedicated channel between devices.
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.
Reclosers	Electro-mechanical devices that can react to a short circuit by interrupting electrical flow and automatically reconnecting it a short time later. Reclosers function as circuit breakers on the feeder circuit and are located throughout the distribution system to prevent a temporary fault from causing an outage.
Reliability Metrics	Reliability Metrics are used to assess the operational performance of the distribution system in terms of reliability and resilience.
Remote Intelligent Switch (reclosers)	Sectionalizing and tie switches that enable shifting portions of one circuit to another for maintenance and outage restoration.
SAIDI (System Average Interruption Duration Index)	The total duration of interruptions for the average customer during a given time period. SAIDI is normally calculated on either monthly or yearly basis; however, it can also be calculated daily, or for any other time period.

Term	Description
SAIFI (System Average Interruption Frequency Index)	The average number of outages a customer experienced during a year.
Satellite Radio Frequency Communications	One of the services provided by the more than 2,000 communication satellites in orbit around the Earth. Satellites have the advantage of unobstructed coverage requiring only a suitable ground station. Satellite radio is used in remote locations where the construction of radio towers or other land-based infrastructure is cost-prohibitive.
Secondary Var Controllers (SVC)	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.
Self-Supporting	Expenditures incurred for a specific customer (e.g., interconnection), with costs directly assigned to those specific customers.
Situational Awareness	A software system that provides real-time visibility to grid and telecommunications network operations and operational data analysis for decision support
Standards and Safety Compliance	Grid expenditures required to ensure reliable operations, or comply with service quality and safety standards
Substation Automation	Utilizing data from SCADA and other Intelligent electronic devices (IED) in combination with substation automation and control capabilities to manage substation operations.
Supervisory Control and Data Acquisition (SCADA)	A system of remote control and telemetry used to monitor and control the transmission system and substation automation.
Synchronous Condenser	A conventional synchronous generator whose shaft is not connected to a prime mover (e.g. steam turbine), but spins freely. Synchronous condensers are used to provide voltage support (through control of the machine exciter) and can supply short-circuit current to the connected system.
System Frequency	Alternating Current (AC) follows a sinusoidal waveform. In the U.S. IEEE 15477 specifies a desired waveform frequency of 60 Hz.
System Inertia	Inertial Response is a property of large synchronous generators, which contain large synchronous rotating masses, and act to overcome the real-time imbalance between power supply and demand for electric power systems.
Transactive Energy	Transactive Energy is defined by techniques for managing the generation, consumption or flow of electric power within an electric power system through the use of economic or market-based constructs while considering grid reliability constraints. Transactive energy refers to the use of a combination of economic and control techniques to manage grid reliability and efficiency.

Term	Description
Transmission and Distribution (T&D)	Electricity grid transporting and delivering energy from central utility scale generation to customers.
Transmission-Distribution interface (T-D interface)	Transmission-Distribution interface (T-D interface) is the physical point at which the transmission system and distribution system interconnect. This point is often the demarcation between federal and state regulatory jurisdiction. It is also a reference point for electric system planning, scheduling of power and, in ISO and RTO markets, the reference point for determining Locational Marginal Prices (LMP) of wholesale energy.
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
Wide Area Network	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.

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Appendix B: Ward Research Electric Grid Modernization Study

WARD RESEARCH

INCORPORATED

Electric Grid Modernization Study

Prepared for:

THE HAWAIIAN ELECTRIC COMPANIES

May 2017

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Table of Contents

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Executive Summary

This summary provides an overview of a two-part qualitative study among key stakeholders of Hawaiian Electric, both energy experts/advocates/large commercial users and residential customers. Twenty-three (23) in-depth one-on-one interviews were conducted among individual stakeholders and 11 focus groups conducted among 82 residential customers. Those interviewed represented constituencies of all three Hawaiian Electric Companies across the three counties. Interviews were conducted late April through late May, 2017, with the overall objective of soliciting input on grid modernization and what is expected/hoped for from the grid of the future.

Dramatic differences were seen in the perspectives coming from the energy experts/advocates/large commercial users and those of residential customers. The hopes and expectations of residential customers align around "what's in it for me". They see a modernized grid as a way to allow more rooftop solar and, ultimately, to reduce cost through the use of this renewable energy source. Even when discussing the integration of "renewable resources" into the grid as a topic of discussion, residential customers view this in terms of rooftop solar and not through a systems-wide lens (e.g., wind, biomass, waste to energy, geothermal, etc.). In this way, the focus on individual rooftop solar – with information coming from solar salespeople, the media, and their friends and neighbors --- really stops them from thinking much further about the renewable, clean energy challenge.

The energy experts and advocates, on the other hand, are clearly focused on Hawaii's goal of 100 percent clean energy. They, too, want to see a greater ability of the grid to incorporate rooftop solar, but take a broader view of the various resources available. Whereas

residential customers tended to express impatience related to less expensive energy and lower bills, the energy stakeholders expressed frustration at the pace of the needed grid modernization, wanting us to be further along than we are now. In the interviews, large commercial users focused their attention on grid stability and flexibility; issues far from the residential user's awareness or consideration.

Reliability is important to all stakeholder audiences, with all expressing relatively high levels of satisfaction with current reliability. Large commercial users provide their customer-side backup, if in critical operations such as health and public safety. Residential customers struggled with the idea of less (or more) reliability, believing that the utility's job is to provide the maximum reliability possible, such that incremental differences are imperceptible to them and the concept not well understood. Some of the energy stakeholders were relatively more familiar with the redundancies needed to achieve greater reliability and the associated costs of those redundancies. They believe the utility should be required to provide a threshold level of reliability, such as is provided now, and the customer should bear the cost of any additional needed reliability.

It must be observed that two videos shown to residential customers in the focus groups ("Two-Way Flow" and "Grid Ops") served to educate them about grid management issues; education that they suggested should be broadly shared with the general population. Prior to viewing the videos, it wasn't uncommon to hear participants refer to "the grid in my neighborhood" or the grid "storing energy to use later". Asked (after seeing the videos) what they learned, most said they had no idea that differing sources of energy had to be "balanced" or that it was a challenge for the electric companies. They also indicated a better understanding of the challenges associated with "excess" energy. With this new understanding, they were able to

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engage in deeper discussion about incorporating renewables into the grid, energy storage, and other timely issues.

Storage (and particularly battery storage, at present) is seen by all stakeholder groups as the "Holy Grail" of our energy future, to quote one of the energy experts. (It must be noted, however, that some residential customers believe that energy can be stored in the grid currently and used when needed.) Customers across all stakeholder groups want to see utility-grade storage located around each of the islands to help stabilize the grid and increase efficiency, while opinions differed regarding who should pay for this. Most feel that this storage will benefit everyone, so the cost should be shared, while others feel this is an expense that should be borne by the utility. There was some interest, among large commercial users and residential customers, in allowing storage facilities on customer premises, from the perspective of contributing toward the greater good. However, there are considerable details that are needed prior to further discussion, with customers asking what's in it for them, can batteries explode or catch fire, are there health hazards related to battery leakage, etc.

Among energy experts and larger commercial users, there is a real interest in better understanding macro-level grid usage patterns and individuals having access to their own usage data. Real time data, to include variable pricing that may change daily, is of great interest to those with an interest in public policy and those able to use sophisticated energy management systems. They see this real time information as key to increasing energy efficiency and controlling costs. Without specific programs to test, however, residential customers do not express this same interest, nor do they display any awareness of this feature. As stated earlier, they remain focused on other issues that have (currently) identifiable benefits to them, such as

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the incorporation of more rooftop solar and features that they believe can reduce their monthly bills.

Relative to who should pay for grid modernization, some interesting dynamics were observed among residential customers. In general, participants across all stakeholder groups believe that the cost of those improvements that will benefit all users (e.g. efforts to allow for the integration of more renewable energy sources, whether residential rooftop solar, wind turbines, or biomass plants) should be shared by all users. This is seen as approaching a "social justice" issue and "for the greater good". However, this commitment softens when considering those improvements that benefit PV owners only; as some do feel that PV owners really are not paying their fair share now. Taking the concept one step further, to grid enhancements that can be allocated to the costs of electric vehicle charging, residential participants were clear that EV owners should pay for these, given the benefits they enjoy currently (e.g. free charging at public facilities and shopping centers, avoidance of gasoline taxes) and their ability to pay for a "premium" car.

Note: Qualitative research is used to gain a deeper understanding of a particular subject. Although findings are not statistically projectable, given that they are based on qualitative data, they have directional value. When themes emerge consistently in qualitative research, such as is observed here, users can have confidence in the direction coming from the data.

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Background and Objectives

This study was created as part of the response to Order 34281 by the Public Utilities Commission, Docket Number 2016-0087, regarding the Hawaiian Electric plan for grid modernization. The Hawaiian Electric Companies commissioned Ward Research to conduct a qualitative study with the following overall objective:

TO BETTER UNDERSTAND THE DESIRED OVERALL FEATURES AND CUSTOMER BENEFITS OF A GRID MODERNIZATION PROGRAM, FROM THE PERSPECTIVE OF A) ENERGY INDUSTRY EXPERTS, ADVOCATES, OTHER INDUSTRY STAKEHOLDERS, AND KEY COMMERCIAL CUSTOMERS; AND B) RESIDENTIAL CUSTOMERS.

A two-part research program was formulated. Part I, discussed in the first section of this report, involved one-on-one interviews with energy industry experts and other stakeholders. Part II, discussed in the latter section, used focus groups conducted among residential customers of the three Hawaiian Electric Companies.

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Electric Grid Modernization Study

Part I: Interviews with Energy Industry Experts and Other Stakeholders

Methodology

This summary presents the highlights from in-depth interviews conducted among twenty-three (23) key stakeholders of Hawaiian Electric Companies (HECO) in May 2017. The interviews were designed to examine perceptions of the current electric grid and their expectations of grid modernization. Open-ended questioning was used to probe into the functions and features desired by stakeholders in order to help design and plan the necessary system to meet those expectations.

To ensure that perspectives across the electric industry were being represented, potential participants were split into four stakeholder categories (industry experts, energy advocates, commercial customers and others) for recruitment. Industry experts consisted of representatives of public and private organizations involved in the energy industry. Energy advocates predominantly came from the non-profit sector. Commercial customers included key commercial and other large users, as well as some medium-sized commercial and industrial accounts across the three counties. Other stakeholders included a mix of representatives from public and private organizations, including three large public sector users.

Participants were first mailed an introductory letter, signed by George Willoughby – Hawaiian Electric Director of Customer Research, which explained the scope of the project and solicited their participation. They were then recruited by phone or email and scheduled to participate in the interview. The interview was either conducted over the phone or in-person, depending on the availability of the stakeholder. At the start of the interviews, participants were again reminded of the project scope and the anonymity of their responses. The interviews

averaged 45 minutes and the table on the next page shows the distribution of interviews by stakeholder type.

Segment	***# of Interviews***
Industry experts	5
Energy advocates	4
Other stakeholders	6
Commercial customers	8
Total Number of Interviews	***23***

All interviews were conducted by Rebecca S. Ward, President and Ty Law, Project Director, at Ward Research. Private sector participants were invited to identify a non-profit to receive a donation; $100 to commercial customers (for a briefer interview) and $150 to other private sector participants.

The interview guide was developed by Ward Research and submitted to the client for review. This guide is in the Appendix, along with the introductory letters to potential participants.

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Summary of Interviews

<u>Hawaiian Electric's role in the future of energy</u>

Many stakeholders cited Governor Ige's clean energy goals of reaching 100% renewable energy by 2045 when asked to describe Hawaii's energy future. They expressed a social responsibility to assist in the goal of having renewable energy in Hawaii. Stakeholders offered various ideas about reaching that goal, but said that they were not married to any specific plans. Stakeholders just want cleaner and cheaper energy as quickly as possible.

> **"The grid is like a country; we all need to be good citizens."**
>
> **"It needs to go towards sustainability and green for customer and energy independence. We can do more. We've got biomass, solar, wind, incineration – to convert landfills to energy."**
>
> **"100% requirement of clean energy is the end state. I'm not wedded to any model but the quicker the better."**
>
> **"The state goal of sustainability by 2040 is a good goal. I hope we can help achieve it ahead of its time."**
>
> **"10 years from now things will look different and Hawaii will be in the middle of it. I expect to see more battery storage, grid-scale and distributed residential systems."**
>
> **"Look for how we can better distribute energy as a whole."**

As the utility company, Hawaiian Electric is considered by many stakeholders to be the industry leader. The company is thought to be well-positioned with the knowledge and existing relationships to lead the initiative. Stakeholders hoped that Hawaiian Electric can help streamline the plan to make it easier for others to assist. Industry experts and a few commercial stakeholders suggested that the company should look for partners in technology, energy generation, and distribution. One energy advocate suggested that Hawaiian Electric should move out of

generation completely and focus on being a distributor. In general, stakeholders were willing to follow the lead of Hawaiian Electric if they believe it is the most effective and quickest route to reach initiative goals and reduce the overall cost of energy. As such, being transparent with information and having two-way communication with Hawaiian Electric was mentioned as being very important by several stakeholders.

> **"There's an opportunity now for HECO to carve out their own plan, absent leadership from elsewhere. They should grab the opportunity, create a vision, a roadmap. Doesn't mean that the roadmap won't change over time, but give us a 10-yr plan that we can all rally around, and find our own places within that vision. We can't plan well unless they stake it out first."**

> **"HECO should take a leadership role and help streamline the process for the entire state."**

> **"HECO is on the right track, we just need them to push a bit harder to get things done faster."**

> **"As much as everyone wants to be off-grid and independent, we will need HECO until tech gets better. We should be working with the utility to get on the same page but there's too much external politics involved that make it difficult. We need to realize that HECO is an asset that is a key component for success and partner with them."**

> **"We need to look locally for our own energy generation. HECO needs to find investment partners in new technology. Perhaps find some co-ops for residential or commercial customers."**

> **"Shut down the main generators and use the local resources. HECO should be moving towards less production of energy and focus on the facilitation of it."**

> **"They need more integrated resource planning. No one asks the community what we want; the only resource in the management plan was windmills. We feel left out and it hurts the credibility of HECO."**

> **"HECO needs to continue to take community input and inform the community of future plans."**

> **"If the utility is the most effective and most rapid way to reach our goals of clean, cheaper energy, then great. If they are an obstacle, then that needs to be fixed."**

Current grid is very reliable

There are two underlying themes, amongst stakeholders, on the current condition of the electric grid. When asked to describe today's electric grid, stakeholders first talked about it in terms of reliability. The current electric grid is described as being very reliable and able to satisfy the energy needs. A few Neighbor Island stakeholders, who say they experience more service disruptions than Oahu stakeholders, did not fault nor diminish their perception of Hawaiian Electric's reliability with outages due to weather issues.

> **"Today's grid is reliable and stable. There are very few outages."**
>
> **"Reliability is very good."**
>
> **"The current grid is fine for where we are at now. We are getting what we need from it."**
>
> **"We have a reliable grid and other than a few outages it's very stable. Occasional service disruptions but are not as frequent. It's not MECO's fault, as they work on it diligently if we have issues."**
>
> **"The current grid is pretty damn reliable."**

Grid needs to be modernized

The secondary theme expressed by stakeholders is that the current grid is old. From the perspective of commercial customers and especially Neighbor Island stakeholders, the grid needs to be updated in order to better withstand weather and other threats. These desired updates are mentioned as a way to maintain or increase reliability of service. Asked to think beyond the present grid system, those involved in public safety are hoping that Hawaiian Electric can address the vulnerabilities in the system that cause the greatest concern after a catastrophic event like a tsunami, hurricane, etc. Those most vulnerable aspects, they said, are the overhead lines and diesel-powered generators. Damage to the harbors would have a compounding effect on public safety, if oil cannot be offloaded in the harbors.

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"Molokai's grid desperately needs updates and repairs. There's just one direct line with no support. The further you are away from transmission the more likely you'll suffer a brownout. Usually the east end experiences 1-2 weekly and the west end once a month."

"Today's grid is unstable and old. When the wind blows, it affects it and when a storm comes, we expect we won't have electricity."

"There was an opportunity through ARRA, after the economic meltdown in 2008, to secure federal funding for grid improvements. Why didn't they take advantage of that? Companies like PG&E were aggressive about those funds and made real progress. So we could have been much further along."

"Electricity has been around for a century and it is not new. In other places power is not an issue but here we have struggles when it gets windy. It's an old grid and weather affects it a lot."

"If they can modernize and harden the system, to allow it to better withstand natural disasters. So that if the system goes down, power can be restored quickly. The system needs to be as resilient as possible."

The age of the current grid is also brought up by energy advocates and industry experts. These stakeholders believe that the grid uses outdated technology and is the primary hurdle that prevents new energy technology from being adopted.

"Antiquated. Can't really blame anyone for not anticipating the issue with distributed generation. No one really could have foreseen how big an issue it would be, not even government or the PUC."

"The grid is old. HECO is working on improvements and integrating various technologies. We definitely have room for improvements."

"The grid needs more lines so that it can compensate for downed lines and so we can have less power outages."

"The grid is antiquated, aging and in need of modernization and repair."

"The current grid is antiquated. It is built for a different model. Not built for 21st Century with the increase in renewable resources."

"I'm not too concerned. It's not antiquated; it does what it needed to do. But it needs to change to adapt to renewable resources."

"The grid is theoretically antiquated. But I don't know much about it."

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However, industry experts and a few other stakeholders expressed uncertainty regarding the capabilities of the current grid. Those industry experts said that they do not have access to current grid performance data and, without that information, it is difficult to comment on what modernization features the grid needs. They asked for more information transparency but understand that Hawaiian Electric needs to maintain a balance between allowing access to usage data and safeguarding that data from cyberattacks.

> **"We need real data on grid performance now. Usage by area, by time of day, and a fair and honest evaluation of that data. Real planning for grid modernization cannot move forward until there is a sharing of that data. I wonder how much of that they have already."**
>
> **"We are missing the data piece on how efficient energy is being used now. We need visibility, access, and real-time data on load usage. I do understand there's a difficulty in granting transparency while maintaining security, but there has to be a solution."**
>
> **"If taking their word for it, then the grid is 'saturated.' If we could get more information about the grid, it would help us understand what the issues are with today's current grid."**
>
> **"We don't have the information to point to a source to see what the capabilities are of the current grid or what updates need to be done to get it to where we want it to be."**

Goals of grid modernization

When asked to consider what grid modernization means to them, stakeholders conveyed that the grid needs to be updated and in a position to implement new technology. Many stakeholders did not have the background to discuss technical features or advances they are hoping for in a modernized grid. However, they suggested that no matter the route, the goals of grid modernization should be to maintain reliability, reach energy sustainability, encourage greater conservation, and all at a lower cost to consumers. One Neighbor Island stakeholder

expressed an outlying opinion, believing that the smaller islands do not need to undergo grid modernization as they already have good conservation practices.

> **"Grid modernization means to be able to utilize and connect newer technology to the grid."**
>
> **"Need to update the grid and implement technology and innovation that exists so that we can keep our commitment to be sustainable."**
>
> **"Coming up to speed with innovation and keeping to the commitment. Be able to use the innovation that exists and implement new technology as it becomes available."**
>
> "**I don't know or understand the technology well enough to know what a modernized grid can or cannot do. But I know there is technology that exists out there and we just have not implemented it."**
>
> **"The modernized grid needs to ultimately support us, to help us be 100% self-sufficient. We don't want to cut ties with the utility company; they need to be around to help us maintain reliability and affordability."**
>
> **"There is no need for grid modernization on the smaller islands. No value in implementation here. We don't need smart meters and don't have solar panels."**

<u>Future reliability is the primary concern</u>

Stakeholders also expressed the belief that future reliability is the main concern for grid modernization. They believe that the purpose of Hawaiian Electric is to deliver power and have it available when it is needed. When asked if they would accept a slightly less reliable grid to reduce costs, almost all of the stakeholders said that they would not trade reliability for lower costs. For commercial customers, loss of power affects customer service and that is detrimental to their business bottom line. Therefore, sacrificing reliability for short term savings actually hurts them in the long run. A couple stakeholders questioned why they could not have both lower costs and a more reliable system in the future.

> **"Grid modernization needs to help efficiency, but reliability is still key."**

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"Future reliability is a concern due to increasing capacity and the associated costs."

"We service so many people that reliability is the main function we need from the grid. I do think that there should be more flexibility for owners to get some benefit for using (renewable energy) technology."

"In general, I hope we incorporate improvements to reliability. Reliability is critical and we don't want to worry about the power going out."

"Personally not important to me, however the visitor industry depends on it. We need to take a big picture approach in maintaining reliability."

"Reliable electricity is critical for us, a priority above all."

"This is a tricky question; I think the technology that exists to increase reliability is not that expensive. We can have both stability and increased reliability with a reduction in costs. There can be a win-win and it doesn't need to be a trade-off."

Many of the commercial customers interviewed said that they have taken steps on their side to maintain reliability for their operations. While stakeholders expect reliability from the utility company, they also understand that there may be circumstances affecting reliability outside of the utility's control. Therefore, commercial customers and other large users incorporate their own backup generators, batteries, and other equipment to maintain a modicum of control over the quality and reliability of electricity. From a health and public safety perspective, redundancies in the system are crucial, and they saw it as a shared responsibility; with Hawaiian Electric providing for it on the utility side and the customer also needing to have backup capacity on their own side.

"Maintaining reliability is a joint effort in Hawaii. We aren't as reliable as the grids on the mainland with their power-sharing agreements. It is a shared responsibility with HECO taking the lead."

"For what we do, we need reliability to provide for our clients."

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> **"On our end, to maintain reliability we have energy savings and performance contracts to guide usage. We have some batteries on site and are trying to do our part to keep reliability high."**

> **"We have VFD, an electric current controller, to help manage on our end. Batteries are expensive and we are trying to get solar."**

<u>Distributed generation to lower costs and reach sustainability goals</u>

A grid modernization feature frequently mentioned, as a way to reduce cost and reach sustainability, is the capacity for greater amounts of distributed generation. In addition to residential rooftop solar, community solar farms, commercially-owned projects, and Hawaiian Electric joint ventures were all brought up as possible routes to approach this distributed generation future. While solar technology was the most commonly mentioned amongst all stakeholder groups, it was not the only type of distributed generation considered. Stakeholders said they were open to examining what the best route may be for a particular region (or island). One possibility mentioned was to examine successful smaller test projects and roll them out slowly on a larger scale.

> **"Enhance smart grid capacity to increase distributed generation based off rooftop solar. Use the hardware to help increase current and future reliability."**

> **"A modernized grid should be able to grant more flexibility, either PV or other alternate sources of energy."**

> **"I do think that the most logical way to go is to allow for diverse, smaller clients to feed into the grid system so that our (smaller) island can be self-sustained."**

> **"Take a regional approach to energy generation and usage. They can base it on geography, weather, and other factors."**

> **"We need a distributed generation system to avoid problems with reliability in the future."**

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"I also want to see HECO deploy more utility-scale projects, like KIUC. Rooftop solar will remain strong, but we need to move into larger projects so that there are fewer inputs into the system for them to manage."

Several issues with increasing distributed generation were brought up by stakeholders. Some stakeholders mentioned the inability of the current grid to handle two-way energy flow as the main roadblock. One energy advocate said that laws prohibiting wheeling and energy distribution require reform, to enable the community to find solutions for energy production and distribution.

"HECO needs to look at addressing the wheeling law that prohibits the generation and selling of energy. It serves to protect the utility but also prevents some new technology in creating community-based microgrid systems."

Real-time data to inform consumer choices

Several energy experts discussed the idea of technology enabling homes and businesses to be smarter, running when energy is less expensive. For example, residential customers with "smart" appliances that will know to start 5 minutes later to take advantage of a better rate band is the next step in real-time pricing. And on the commercial side, "smart engineers will manage commercial usage, or automation will, through energy management systems."

"Time-of-use pricing is important to send right signals to use electric when it is cheap and to not use it when it is expensive."

"Imagine when homes and businesses are smarter and devices run when energy is cheap."

"Time-of-use rates can help set clear price signals and help change our behaviors toward energy use."

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Different ways to approach variable pricing

Industry experts said that while variable pricing is what Hawaiian Electric should be striving for, there is no clear and easy route to accomplish this. Amongst stakeholders, there are differing ideas on whether variable pricing should be based on time of use or consumption levels, or when one would be more "fair" than another. However, all stakeholder groups expressed concern that variable pricing needs to be equitable and take into account residents with lower socio-economic status. These residents may not be able to adjust their usage (due to employment situations) or purchase smart devices to take advantage of savings, and may be unjustly penalized due to their circumstance. A few stakeholders felt that variable pricing may make sense in more urban areas and some commercial stakeholders said that it would not affect their usage at all.

> **"Real-time use pricing is probably the Holy Grail of pricing models but how do we get there from here?"**
>
> **"The challenge is in figuring out how time of use pricing and demand response, or load curtailment programs, can work together. As it is now, we would see TOU rates as a way of controlling our demand charges. So that, ideally, our peak demand is not at HECO's peak demand time."**
>
> **"Variable pricing based off of consumption would make more sense if we are moving towards battery storage anyway. Then the usage would be drawing from batteries and not tied to current production."**
>
> **"We need to maintain equity so that everyone can benefit from the system change."**
>
> **"I like the idea of variable pricing but we need to be aware of people in different economic thresholds that may not be able to adjust their usage based on the shifts that they work. I don't think there should be a one-size fits all solution and we need to find a tiered solution."**
>
> **"We understand the need for variable pricing in some places, but it's not worth implementing if we can't adjust usage. It may wind up paralyzing people who cannot adjust usage. Not equitable."**

"It is an interesting concept for urban areas. Rural sections may not work as well since electricity is often conserved due to high prices."

"Variable pricing could be more for residential than commercial. I don't see us cutting back on our usage because we need to use it when we do."

"For us it doesn't matter. The facility needs to be run 24 hours and the timing won't affect our usage."

Advantages and concerns with smart meters

While many stakeholders felt that moving toward variable pricing will lead to energy conservation and reducing consumer costs, industry experts believe that smart meters are required to take full advantage it. They think that the grid can provide real-time usage information to smart meters which could then send pricing changes to programs that can communicate with and control smart devices. Consumers can then see what is happening in their home with real-time usage and be able to adjust their behaviors.

"Smart meters should be looked into, with functions to have control over energy use and provide reliability to the grid."

"If the (modernized) grid could supply meters and hardware to track variable pricing then that would be great. It would mean that they are not just fulfilling the status quo but going above and beyond."

"We need smart meters to help new technology thrive. We need to be able to test it before a larger roll-out."

"The technology has to be there. Be able to track energy flowing in and out to be able to take advantage of time of use pricing."

"More tools to get instant feedback and customers can examine their own usage patterns. HECO can help by examining usage patterns and individually tailor tips on how to reduce bills at the individual level."

"It's the ability of ratepayers to know what's going on in their own homes, the real time usage information. This will educate customers on how they're using electricity and allow them options for changing behaviors for TOU rates, etc. Once people get access to this information, they find out how useful it is. It's happened with the PV customers who now have smart

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meters and can see when they're producing and when they're consuming. They really get into it."

There are concerns over the safety of using smart meters shared by a few industry experts and energy advocates. The industry experts want access to the information that smart meters have in order to be able to build and program better ways to manage electricity, but also feared that it can be used in malicious ways. While energy advocates are interested in the benefits of smart meter technology, they asked for more information and transparency with regard to installation and possible health risks.

"We want more transparency of information but understand at the same time HECO has to safeguard the information from attacks."

"We are worried about privacy issues and security threats from the installation of smart meters."

"I think we need smart meters but there is a decent amount of people who want to help the environment but are concerned about the health impact of smart meters. HECO needs to figure out what the issues are, limit the impact on others, and educate us all on it."

Energy storage is the future

A few commercial stakeholders brought up batteries when discussing how to maintain their own energy reliability. Batteries to store excess solar energy were also mentioned by industry experts as the game changer to help balance supply and demand. One industry expert suggested building storage based off of usage patterns and projections. However, high overhead and short lifespan were acknowledged as roadblocks in considering batteries as a storage solution.

"The whole world is screaming for an affordable option for storage. On the residential side, yes, it's approaching affordability, although not so that homeowners can really live off the grid. We're not all Elan Musks or Henk Rogers, who can afford it. But for really large commercial users, I just don't see that battery storage will be practical in my lifetime."

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"If it is cheaper than the alternative then we should absolutely consider battery storage. Bottom line is to find the cheapest solution possible for consumers."

"Part of the need for additional data is the need to understand how much power is needed where. So the utility should map it out, and strategic storage planning should follow. And it shouldn't be all utility scale storage; much of it can be customer-sited, to increase reliability at the customer level. So let the market dictate the non-strategic storage."

When probed if Hawaiian Electric should bear the cost and responsibility of building batteries to store excess energy to deliver it to customers, stakeholders expressed a variety of opinions. A few energy advocates and commercial stakeholders felt that Hawaiian Electric should be responsible for building and paying for the battery system, otherwise commercial businesses would pursue their own options and go off-grid. Others reflected that even if Hawaiian Electric was initially responsible for paying for the battery system, those costs would appear in future rates. Industry experts and several commercial stakeholders believe that bearing the cost of batteries should be a joint responsibility between Hawaiian Electric and partners. They did not think there was one solution for the state and, instead, would want Hawaiian Electric to explore multiple ways to incorporate batteries as cheaply and quickly as possible. One industry expert mentioned that Hawaiian Electric could try to work with the customers of solar companies to access existing batteries and save on overhead.

"In my lifetime, HECO is going to need to be there as back-up. This is why we need to figure all of these things out - we need a viable electric utility."

"HECO is responsible for the mess of distributed generation; they created the mess so they should solve it. They should not place the burden on the ratepayers but should take responsibility with their shareholders."

"HECO should pay for batteries and other technology to reduce costs. In 2-3 years HECO is going to lose their client base by 20% if they do not work with their clients in reducing the cost of energy. HECO buys energy. If they have

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more options on where to purchase and distribute energy, it can reduce the price. We have no control over the oil prices but can access solar/wind."

"Realistically, everyone should have their own battery and pay an opt-in fee to access HECO's power grid."

"We need different models and ways to approach this. I don't think HECO should build the batteries, and people can't afford to build the batteries without loans. Find ways to provide different solutions for different people."

"Either way we'll end up paying for it, so they should just do whichever is the quickest way."

"With DG around the island, HECO has the opportunity to work with solar companies' customers who have batteries. If they can access the power in those batteries, they'll have power without the capital expense themselves. And this is power that they can use to support and stabilize the grid."

A few industry experts mentioned alternate energy storage procedures when discussing batteries. They brought up hydrogen as a possible storage medium and mentioned possibilities of using hydro-alternatives, such as a system to pump water up during the day and then letting it flow at night to create energy. One industry expert said that he "sees pumped hydro as the only practical means of shifting generation."

"Hydrogen is also a storage medium, and there are an increasing number of hydro solutions as well."

"Batteries are not economical. So we are working on a pilot with the University, looking at pumped hydro to create hydroelectricity. However, there are challenges due to elevation requirements and available storage."

Provide flexibility and options

Like the discussion on batteries, stakeholders suggested that grid modernization should not be "one-size fits all." They said that Hawaiian Electric should grant options, to allow consumers to choose the type of energy they access. "The demand for customer choice might also create bundled options for Hawaiian Electric", one expert said, "such as are currently

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offered in the internet-television-phone arena by Oceanic and Hawaiian Telcom." A premium package might allow customers to support greater renewable options through higher "green" pricing, with marketing and messaging being extremely important.

Similarly, commercial stakeholders wanted to have the flexibility to pursue their own energy solutions, yet still be connected to the grid without incurring (what they describe as "punitive") demand charges. Industry experts thought that, if the utility can grant more options to their customers, there will be no need to look elsewhere for power. This notion is reinforced by some frustrated commercial stakeholders who feel that they are unable to work with Hawaiian Electric to access low-cost and renewable sources of energy and are searching for their own solutions.

> **"Allow for more customer choice. There are disruptive forces that are more entrepreneurial, that aren't bound by the PUC, that could do great harm to the utility if they make deep inroads. Like Uber did to transportation, and Airbnb did to lodging. The utility is not known for innovation, so how can they head off these disruptors, since we need a strong utility? The key is customer choice."**
>
> **"We should have the tools to help us control the type (e.g. solar, coal) of energy we are choosing to use. In the near future, we need tools for instant feedback, to help us aid, compare, and adjust our personal usage patterns."**
>
> **"Customer choice means options such as time-of-use pricing, real time pricing, green pricing, more rooftop solar, community solar."**
>
> **"We should have the ability to install solar, batteries, and other on-site energy resources while staying connected to the grid without headaches or hassles."**
>
> **"The demand charges are so punitive it makes no sense to connect to the grid if we have our own generator and battery system. It deters us from wanting to share cheaper, clean energy with our neighbors."**
>
> **"If they want to stay in business then they need to develop options to reduce electric costs. Otherwise we will look and invest in our own."**

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Sense of urgency for grid modernization

Urgency colored many of the stakeholders' interviews during the discussion of various ways and possibilities of approaching grid modernization. Stakeholders said they understood the need for collaborative input and proper planning, but wished the process of grid modernization was further along than it is today. They appreciated the discovery process that Hawaiian Electric is engaging in, but stressed that Hawaii needs to reach the state's energy goals sooner rather than later.

> **"My thoughts on grid modernization is to do it."**
>
> **"We can get to our goals of renewable energy quicker than 2045 and should aim for that."**
>
> **"I hope we can all work together to get this accomplished quickly."**
>
> **"HECO is on the right path. We just need to push them a little harder to get us there and include the community in its solutions."**

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Electric Grid Modernization Study

Part II: Focus Groups with Residential Customers

Methodology

The Hawaiian Electric Companies commissioned Ward Research to conduct focus groups to better understand the desired overall features and customer benefits of a grid modernization program, from the perspective of residential customers.

Eleven focus groups were conducted from May 1 through May 24, 2017, among 82 Hawai‘i Electric Light, Hawaiian Electric, and Maui Electric residential customers. Focus group participants were screened to include only those who:

- Pay a bill directly to their electric company (not included in rent or maintenance fee);
- Are the head or one of the heads of the household;
- Are between 21-74 years of age;
- Are not currently residing in a Smart Grid Pilot area;
- Rated the reputation of their electric company a 3-5 on a 5-point scale, where 1=very unfavorable and 5=very favorable.[1]

The focus groups were segmented by PV system ownership, as shown in the table on the next page. Except in Kona, the No PV groups were further segmented so that those who rated their electric company's reputation a 3-4 were placed in a different group than those who rated their electric company's reputation a 4-5 on a 5-point scale where 5=very favorable.

Participants were recruited from the Ward Research Participant Referral Database and reflected a cross-section of customers by demographic characteristics such as gender, ethnicity, occupation, household income, and area of residence.

[1] Excluding customers who offer lower, 1-2 ratings is standard practice for focus group selection, since it can be difficult to have a productive discussion among those who may not be able to focus broadly on other topics beyond their unfavorable feelings or opinions.

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	PV Ownership	Date(s) Conducted	Number of Groups	Number of Participants
Hawai‘i Electric Light – Hilo	No PV	May 1, 2017	2	16
Hawai‘i Electric Light – Kona	PV	May 2, 2017	1	6
Hawai‘i Electric Light – Kona	No PV	May 2, 2017	1	8
Hawaiian Electric	PV	May 17, 2017	1	8
Hawaiian Electric	No PV	May 17-18, 2017	3	24
Maui Electric	PV	May 24, 2017	1	8
Maui Electric	No PV	May 24, 2017	2	12

All of the groups were moderated by Rebecca S. Ward, President of Ward Research. A discussion outline was created prior to the conduct of the focus groups and is appended to this report. Each group lasted approximately 90 minutes, from 5:00pm-6:30pm or 7:00pm-8:30pm; because of scheduling conflicts, one group was held from 11:30am-1:00pm. Participants in the daytime group were paid a cash gratuity of $100 and all other participants were paid $70. Parking was validated and light refreshments were served.

The focus groups with Hawai‘i Electric Light customers were held in the Hilo Hawaiian Hotel and the King Kamehameha Kona Beach Hotel. The focus groups with Hawaiian Electric customers were held in the Ward Research focus group facility in downtown Honolulu. The focus groups with Maui Electric customers were held in the Courtyard Maui Kahului Airport Hotel. All of the focus groups were videotaped and were observed by representatives of the Hawaiian Electric Companies from an adjoining room.

Characteristics of Focus Group Participants

	Group 1-2 Hilo No PV	Group 3 Kona PV	Group 4 Kona No PV	Group 5 Oahu PV	Group 6-8 Oahu No PV	Group 9 Maui PV	Group 10-11 Maui No PV	Total
Electric Company Reputation Rating								
3	3	1	6	6	6	3	6	31
4	9	3	1	1	13	5	5	37
5=Very Favorable	4	2	1	1	5	0	1	14
Gender								
Male	7	2	6	3	10	3	7	38
Female	9	4	2	5	14	5	5	44
Age								
21-34 years old	2	0	1	0	3	1	2	9
35-44 years old	8	0	0	2	6	0	4	20
45-54 years old	1	1	5	0	5	2	2	16
55-64 years old	4	1	2	5	7	5	3	27
65-74 years old	1	4	0	1	3	0	1	10
Household Income								
Less than $25,000	4	1	1	1	0	1	0	8
$25,000-under $35,000	1	1	1	1	2	0	0	6
$35,000-under $50,000	1	0	4	0	1	0	2	8
$50,000-under $75,000	5	1	1	2	5	1	1	16
$75,000-under $100,000	3	1	0	2	8	1	5	20
$100,000 and above	2	2	1	2	8	5	4	24
Education								
Less than High School	0	0	0	0	1	0	0	1
High School Graduate	4	0	1	1	2	0	1	9
Some College	3	3	3	3	6	3	3	24
College Graduate	4	0	2	2	11	4	4	27
Post-Graduate Studies	2	2	1	0	1	0	3	9
Advanced Degree	3	1	1	2	3	1	1	12
Home Ownership								
Own	8	6	7	8	14	8	7	58
Rent	8	0	1	0	10	0	5	24
Total	**16**	**6**	**8**	**8**	**24**	**8**	**12**	**82**

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Characteristics of Focus Group Participants

	Group 1-2 Hilo No PV	Group 3 Kona PV	Group 4 Kona No PV	Group 5 Oahu PV	Group 6-8 Oahu No PV	Group 9 Maui PV	Group 10-11 Maui No PV	Total
Type of Housing								
Single-family	13	4	6	8	11	8	10	60
Multi-family	3	2	2	0	13	0	2	22
Ethnicity								
Caucasian	4	6	4	3	8	4	4	33
Chinese	1	0	0	0	1	1	0	3
Filipino	0	0	0	1	1	1	0	3
Hawaiian/part-Hawaiian	4	0	4	2	7	1	4	22
Japanese	3	0	0	2	6	1	2	14
Mixed	3	0	0	0	0	0	2	5
Other	1	0	0	0	1	0	0	2
Occupation								
Clerical	1	0	0	1	0	2	0	4
Construction	1	0	0	0	2	1	0	4
Disabled	1	0	1	0	0	0	0	2
Education	2	1	0	1	4	0	3	11
Healthcare	4	0	2	2	1	0	1	10
Homemaker	1	0	0	0	1	0	0	2
Manager/Administrator	1	1	2	0	6	2	2	14
Professional	1	0	0	0	0	1	2	4
Retired	0	3	0	2	3	2	1	11
Sales/Supervisor	0	0	0	1	4	0	1	6
Self-Employed	1	1	0	0	3	0	1	6
Service Worker	0	0	1	1	0	0	0	2
Skilled Laborer	2	0	1	0	0	0	1	4
Student	1	0	0	0	0	0	0	1
Unemployed	0	0	1	0	0	0	0	1
Total	**16**	**6**	**8**	**8**	**24**	**8**	**12**	**82**

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Characteristics of Focus Group Participants

	Group 1-2 Hilo No PV	Group 3 Kona PV	Group 4 Kona No PV	Group 5 Oahu PV	Group 6-8 Oahu No PV	Group 9 Maui PV	Group 10-11 Maui No PV	Total
Area of Residence – Hilo								
Hamakua	2	---	---	---	---	---	---	2
Hilo	9	---	---	---	---	---	---	9
Keaau	3	---	---	---	---	---	---	3
Mountain View	1	---	---	---	---	---	---	1
Waiakea	1	---	---	---	---	---	---	1
Area of Residence – Kona								
Captain Cook	---	0	1	---	---	---	---	1
Honokaa	---	0	1	---	---	---	---	1
Kailua Kona	---	4	5	---	---	---	---	9
Waikoloa	---	2	1	---	---	---	---	3
Area of Residence – Oahu								
Central/Mililani	---	---	---	2	3	---	---	5
Ewa Plains	---	---	---	2	4	---	---	6
Honolulu	---	---	---	2	11	---	---	13
Windward	---	---	---	2	4	---	---	6
North Shore	---	---	---	0	2	---	---	2
Area of Residence – Maui								
Kahului	---	---	---	---	---	1	1	2
Kihei	---	---	---	---	---	1	2	3
Upcountry	---	---	---	---	---	3	7	10
Wailuku	---	---	---	---	---	3	2	5
Total	**16**	**6**	**8**	**8**	**24**	**8**	**12**	**82**

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Narrative of Findings

RATING CUSTOMER PRIORITIES

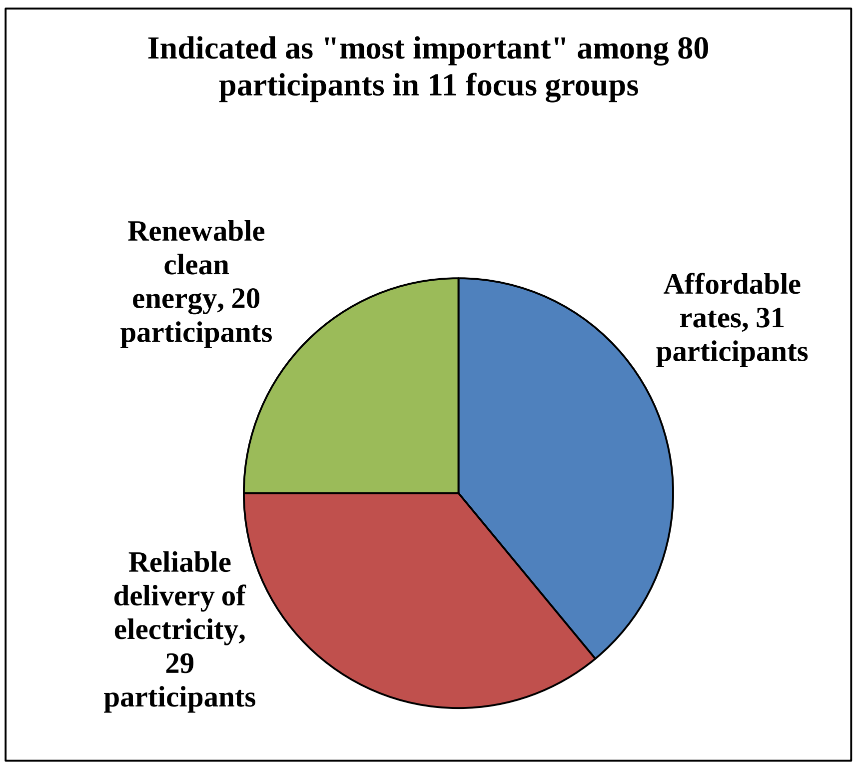
To determine what is most important to customers, without asking them directly, focus group participants were asked to rate priorities for the Hawaiian Electric Companies through the following exercise:[2]

Recognizing that all of these efforts are important and that they can't walk away from any of them, how should your electric company prioritize the three efforts noted below? Put a "1" by the most important, a "2" by the second most important, and a "3" by the third most important.

- **Reliable delivery of electricity**
- **Affordable rates**
- **Renewable clean energy**

Along with revealing what is most important to customers, this exercise led to discussions of the company's perceived performance on the three very important efforts.

For each of the efforts, large segments of customers said that they are very important and should be the top priority of the Hawaiian Electric Companies.



[2] Two participants did not complete the exercise.

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Affordable Rates

The high cost of electricity continues to be a source of dissatisfaction among customers. Those who said that affordable rates should be the most important priority cited high electric bills, and some expect that bills will only become higher, no matter what steps they take to reduce their electricity use.

> **"Cost of living in Hawaii has increased tremendously. Electricity is my highest monthly bill. This is why I'm mostly interested in affordable rates." – Hawaiian Electric Customer**

> **"I chose affordable rates because the cost of living here in Hawaii is increasing. I really want renewable energy, but I want to be able to afford electricity." – Maui Electric Customer**

> **"Cost of living in Hawaii is so high. Our electricity rates should be affordable, especially since we only have one electric company." – Maui Electric Customer**

Some customers prioritized affordable rates because they are more satisfied with their electric company's reliable delivery of electricity and pace of adoption of renewable energy than with their ability to keep electricity rates down.

> **"Electricity rates are too high. Hawaii Island already has more solar than HELCO grids can take. HELCO is pretty good at delivering reliable electricity already." – Hawai'i Electric Light Customer**

> **"I want to be environmentally conscious but electricity is already expensive and I don't want rates to go up even more. HELCO does reliable delivery extremely well already." – Hawai'i Electric Light Customer**

> **"I think affordable rates are most important because electricity is still expensive and they need to keep rates down. As far as reliability of electricity, they are doing a good job and more and more people are using renewable clean energy." – Hawaiian Electric Customer**

Even some of the customers who felt that renewable energy should be prioritized did so hoping that greater integration of renewable energy sources may lead to more affordable rates.

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"I would say cleaner energy would lead to more affordable rates and help the environment." – Hawai'i Electric Light Customer

"By focusing on renewable energy, you can bring the rates down." – Hawai'i Electric Light Customer

"The cost of electricity is really getting out of hand. I feel that if we start moving away from fossil fuels, then our electric bills will be cheaper by using solar, wind, and ocean power." – Hawaiian Electric Customer

"I feel the electric company should focus on renewable clean energy because this will allow them to be less dependent on oil and the cost of electric will be lowered." – Maui Electric Customer

Reliable Delivery of Electricity

Based on the discussions, reliable delivery of electricity is also most important to a sizable segment of customers. Those who said that reliable delivery of electricity should be the most important priority said they rely on it for their daily needs, convenience, and entertainment.

"Reliable delivery is most important to me because we need electricity to run everything in my house. We even need electricity to run the water, since we are on a catchment." – Hawai'i Electric Light Customer

"We need electricity to run a lot of things at home and at work. I think a lot of people would be inconvenienced if reliable delivery of electricity is not the top priority." – Hawaiian Electric Customer

"Reliable electricity affects every aspect of our lives. I want to be able to do what I want to do when I want to do it and almost everything I want to do requires electricity. I took care of my parents in my home and some of their medical equipment required electricity. It would have been devastating to not have electricity." – Hawaiian Electric Customer

"When we lose power, it affects the electronics in my home and it's a pain for me to have to reset and reprogram things as a result of the power loss." – Maui Electric Customer

Many consider electricity a necessity and without reliable delivery of electricity, affordable rates and renewable energy reportedly do not matter.

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"It has to be reliable. Otherwise, the other two choices do not matter." – Hawai'i Electric Light Customer

"Reliability is key. Even if rates are affordable or if energy is renewable, if the service is not reliable, they do not matter." – Maui Electric Customer

Renewable Clean Energy

Many of the customers who said that renewable clean energy should be the top priority of the Hawaiian Electric Companies reportedly did so to save the environment for their children and grandchildren.

"For the sake of my children and the environment, I chose clean renewable energy. The other two are important as well but, thinking of the future, I think renewable energy is most important." – Hawai'i Electric Light Customer

"I think it is important to use other options, especially clean energy options, to preserve our environment." – Hawaiian Electric Customer

"We must take the long view and act in the best interest of our collective future. What good is cheap, reliable energy if it ruins the planet?" – Hawaiian Electric Customer

"Clean energy is important in our ever-changing world. I am at a point in my life where the future for my family is most important." – Maui Electric Customer

"I chose renewable, clean energy because the environment, what with climate change and so on, is at such a tipping point." – Maui Electric Customer

"If we continue to treat the earth as we are doing now, it will lead to an earth that people can no longer survive on. We must protect our earth for future generations." – Maui Electric Customer

"I preferred renewable clean energy because protecting the environment is a continuing priority." – Maui Electric Customer

But, as mentioned earlier, other customers said renewable energy should be the most important priority because they believe that greater integration of renewable energy sources may result in lower rates and greater reliability. This is also the reason why, when asked, some said

that they would be willing to pay more for greater integration of renewable energy, such as PV, into the grid---because they expect that greater integration of renewable energy will result in lower rates and greater reliability in the long run.

> **"I think that I would be willing to pay more, not much more, but if I am going to pay more, then I am looking at it more like an investment. I would want my bills to go down after a certain time." – Hawaiian Electric Customer**

> **"I would pay more for more renewable clean energy. Hawaii has many options. We have wind, we have solar. I don't really understand why we aren't taking advantage of these sources already, but I think that in the long run, doing so would save us more money and make the system more reliable." – Maui Electric Customer**

The delivery of electricity is reliable

Residential customers are satisfied with the delivery of electricity and find it reliable overall. Some of those who said that reliable delivery of electricity should be the most important priority reportedly did so because they have had little or no problems with reliability and felt that the electricity companies should focus on the areas where there are problems (i.e., affordability, renewables). Customers understand that there may be circumstances affecting reliability outside of the companies' control, but aside from the occasional power glitches and longer outages caused by inclement weather or car accidents, customers said they do not lose power (and on the rare occasion that they do, it is usually restored very quickly).

> **"The only times when the power has gone out were because of storms, and I expect that to happen. But I can't even really fault them for that because their workers would be out there, in the rain, trying to restore power as quickly as possible." – Hawai'i Electric Light Customer**

> **"I don't have any complaints about reliability. I haven't experienced a power outage in a long time. Sometimes, there is the occasional glitch, but it is usually just a few seconds, so it does not bother me." – Hawaiian Electric Customer**

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"Maybe I've been really lucky, but I can't think of a time recently when I have lost power. I am very satisfied with reliability." – Maui Electric Customer

When asked if they would be willing to accept "slightly" less reliability for lower costs, nearly all of the customers in the focus groups said that no, they would not. Customers believe that the purpose of their electric company is to deliver reliable power, so found this option confounding. Many of the customers also struggled with the concept of "slightly less reliability"---does this mean power glitches every now and then, scheduled power outages late at night when they would not notice, or rolling blackouts? Customers reiterated the importance of electricity in their daily lives and how much they depend on electricity. The few customers who said they would consider less reliability for lower costs will need additional information first, such as the extent of any outages.

"I would love for the cost to be cheaper, but we need it to be reliable for our day to day lives. We need electricity for work and home and school. We need to have electricity all the time." – Hawai'i Electric Light Customer

"I wouldn't want to do that. Rates are high and we're always looking to save money, but I need my electricity to be dependable. And what does that even mean, 'less reliability'? Does that mean that they can turn off my power whenever they want?" – Hawaiian Electric Customer

When asked the reverse, if they would be willing to pay more for greater reliability, nearly all of the customers again said that no, they would not. Reliable delivery of electricity is important to customers, but they are already generally satisfied with the reliability of their electric service. Responses to this question may change if satisfaction with reliability declines. Some customers also found this option of having "more" reliability hard to understand, since there is an expectation that the electric companies should provide the maximum reliability possible ("Aren't they already? Isn't that their job?"). The few customers who said that they

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would be willing to pay more for more reliable delivery of electricity were those who need electricity for their livelihood or to power medical equipment.

> **"My electric service is already pretty reliable. I don't know if I've just been really lucky, but I haven't had any major problems. I don't think I would be willing to pay more." – Hawaiian Electric Customer**

> **"My bill is already pretty high and I haven't had any major problems. Sometimes it goes out because of an accident or something like that, but it doesn't last very long. It doesn't last long enough that I would want to pay more." – Maui Electric Customer**

THE STATUS OF THE CURRENT ELECTRIC GRID AND THE CAPABILITIES OF A MODERN ELECTRIC GRID

The electric grid needs to be modernized

Customers know very little about the electric grid or how it works; some in the focus groups did not even know what "the grid" is. Among many, their understanding of the electric grid went only as far as, "The grid is where electricity is made and transferred and how it moves between places." Although most of the customers could not talk about the capabilities of the current electric grid, they believe that the electric grid is old, saturated, and needs to be modernized. The perception that the electric grid is old was based largely on the sight of old electric poles and "messy" wires. But, along with suggesting that the electric lines be buried underground, customers also said that the grid needs to be updated to better withstand inclement weather and the occasional car driving into a utility pole. The perception that the grid is saturated was based on stories of customers being unable to install PV and being told that it is because the grid is saturated. There is also a perception that each community is its own grid---no doubt coming from PV saturation messages. This belief that the electric grid is old and saturated led many customers to conclude that the grid "cannot handle" any more PV.

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“The electric grid is saturated and they can’t put any more PV without upgrading it.” – Hawaiian Electric Customer

“The electric grid is infrastructure that transports electricity from one location to another and where electricity is stored and generated. From what I understand, and if it’s anything like the rest of the country, it’s old and in serious need of upgrading.” – Hawaiian Electric Customer

When asked if the grid should be modernized, most customers said that yes, it should be, and some felt that the Hawaiian Electric Companies should have done so a long time ago. When asked to consider what a modern electric grid should be able to do, customers, after some time, said unaided that a modern electric grid should enable greater integration of rooftop solar or PV.

“There wouldn’t be power lines overhead. In a lot more modern areas, the power lines are buried. It looks prettier and it seems like it would be safer.” – Hawai‘i Electric Light Customer

“As I understand it from things I’ve read, one of the problems with the grid is that not everyone can push power out to the grid all the time. The official rumor seems to be the grid is not smart enough to handle the shifts in demand. I don’t know if I accept that, but I would think a more modern grid would be able to address those types of concerns.” – Hawai‘i Electric Light Customer

“More people want to get PV and it’s a slow process because the development of the grid to handle more PV is going very slowly.” – Hawaiian Electric Customer

“Right now, because the grid is so saturated, people who want to put in PV can’t, so an upgraded grid should be able to do that.” – Hawaiian Electric Customer

“I know some people who can’t put PV on their roofs because their neighborhood has too much PV already and the system can’t handle it. So an upgraded system should be able to do that.” – Hawaiian Electric Customer

A modern electric grid should enable greater integration of renewable energy sources

Anticipating customers’ very limited knowledge about the electric grid and grid management issues, two videos about the electric grid were shown during the focus groups in

order to encourage a deeper discussion about the capabilities of a modern electric grid. The two videos were:

- Maintaining Safe and Reliable Energy for Customers (https://www.youtube.com/watch?v=QECzuo8WD4I)
- Managing a Two-Way System to Integrate More Renewable Energy (https://www.youtube.com/watch?v=nH47jRCk5cw)

Customers were very surprised at what they learned from the videos, especially what is required of the grid to handle the two-way flow of electricity and the constant balancing act between firm and intermittent energy. This is important information for customers to know, they said, and suggested that the videos be more widely disseminated to encourage support for grid modernization.

> **"It's the first time that I learned that if the sun goes down, then the firm part has to kick up to equalize the grid or it shuts down. I did not know that." – Hawai'i Electric Light Customer**
>
> **"I didn't know anything about the grid, so that was helpful. It's an intricate process that you have to constantly manage. It makes sense that they would collect energy from all of the houses. I just don't really know how it works. It explains a little bit of it. I thought the houses actually somehow had their own little bank of electricity and they could use it on their own time." – Hawaiian Electric Customer**
>
> **"I didn't realize we had to really keep the different types of energy so carefully balanced and that we could actually damage the system if there's a spike." – Hawaiian Electric Customer**
>
> **"I didn't realize that the more renewable energy is produced, the firm energy needs to go down and that if we are not producing enough renewable energy, then the firm energy needs to go up. It is a balancing act and there needs to be someone to control that balancing act. I never really thought about it before." – Maui Electric Customer**

After watching the videos, customers in the focus groups said that a modern electric grid should be better able to balance firm and intermittent energy and with less effort. They also

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suggested more strongly that a modern electric grid should allow for greater integration of renewable energy sources.

> **"It has to be engineered well so that it can balance all of the energy coming from all of the different sources." – Hawaiian Electric Customer**

> **"Trying to incorporate renewable energy sources without upgrading the grid is like putting a new kitchen in a house that needs to be knocked down. Why would you do that?" – Hawaiian Electric Customer**

> **"Traditional grids can't appropriately handle all of the different types of energies that are coming in. If they are working on improving that, then we can run more efficiently and better handle and store energy." – Hawai'i Electric Light Customer**

One or two of the more technically-oriented residential customers also discussed the idea of a modern grid being able to collect real time data so that the electric companies can determine usage patterns and help them balance the grid. They will know when and where demand is highest and anticipate need accordingly, they said, ensuring a more reliable delivery of electricity.

Energy storage is essential

A few customers suggested, unaided, that a modern electric grid should be capable of storing excess energy produced by renewable sources. These customers either have PV systems installed and have looked into batteries, have considered installing a PV and batteries were mentioned by solar contractors or friends and relatives who have PV, or are more technically-oriented than the average customer. After watching the videos, more customers became convinced that energy storage or the ability to use stored energy is an essential component of a modern electric grid. There was some uncertainty, especially among those who do not have PV, as to whether the electric companies are already capable of storing energy for later use. As expected, PV owners were more likely to be aware than were customers without PV of energy

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storage challenges. A few mentioned that Tesla has developed batteries to store energy. While there was some interest in buying batteries for their home use, the high cost is a barrier.

> **"It seems storage is what's missing. I don't know the technology on it or if it's even possible. If all the energy could go into one storage system, they could put out one steady flow. You don't have to go up or down." – Maui Electric Customer**

> **"It was brief, but they mentioned it in the first video about connecting solar and wind to a battery. Then the battery can maintain a steady flow of power into the grid and as the sunlight changes or the wind speed changes it'll recharge the battery at a different rate. I think I've seen this technology before where there was a solar farm and they had battery storage, so the supply of power would be stable. I think that's why some of the wind farms shut down at night or they're not always running in order to maintain a certain power level." – Maui Electric Customer**

Instead of third parties (such as Tesla) or themselves (because of high overhead costs) customers would prefer that the Hawaiian Electric Companies bear the cost and responsibility of building batteries or storage facilities to store excess energy.

> **"I think that it would be more efficient if HECO does it and that makes a lot more sense. If they are going to use it, they might as well build it." – Hawaiian Electric Customer**

> **"The electric company should take care of it, right? If they are going to use it to power the grid and they are going to be accessing it anyway, then they should build it and take care of it." – Hawaiian Electric Customer**

> **"They should build it because they are the experts. I wouldn't want just regular customers taking care of it." – Hawaiian Electric Customer**

> **"I would just be scared that Maui Electric would turn it over to a private company who's going to charge us for running that. Some big corporation is going to come in and say, 'we can do this for you,' and they take over and next thing you know, we're paying triple." – Maui Electric Customer**

The suggestion of electric storage units or facilities was favorably received, but the suggestion of installing storage units on customers' property, possibly in exchange for lower rates or some type of fee, was more tentatively received. Customers did not bring up any privacy

concerns, but did ask about any possible health and safety risks for installing a storage unit on their property---will it pose a risk to their health, the health of their families, or the health of their pets; is it a fire hazard; will it explode; will it leak chemicals; what about radiation; and so on.

> **"I would need to know how safe it is first. I would not want it in my backyard if it is not safe." – Hawaiian Electric Customer**

> **"Safety would be the foremost concern for me. What are the dangers? Could it blow up my house one day?" – Maui Electric Customer**

<u>THE COST OF MODERNIZING THE ELECTRIC GRID</u>

The cost of modernizing the grid is a concern

Ideally, the cost of grid modernization would be borne solely by the Hawaiian Electric Companies or with help from the state, customers said. However, customers expect that the cost of the upgrades will be passed to ratepayers through higher rates.

> **"It would be great if we didn't have to pay for it, but we're probably going to end up paying for it." – Hawaiian Electric Customer**

> **"I would yell at lawmakers. Didn't they pass that law that says Hawaii is going to be 100% renewable energy by a certain year? I would argue why the expense is coming to the customers and why isn't the government subsidizing the cost?" – Hawaiian Electric Customer**

> **"You would think that the electric company would pay for it, but you know that, eventually, those costs would come down to the customers. I don't know what they've been doing with all their money and why they can't use that to pay for it." – Hawaiian Electric Customer**

As indicated by the next paragraphs, customers would be more willing to undertake the cost if they feel that the upgrades will lead to future benefits such as more affordable rates, more reliable delivery of electricity, and greater integration of renewable energy sources, such as PV.

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The cost for parts of the grid upgraded to enable greater integration of renewable energy sources into the grid should be distributed to all customers

Customers support greater integration of renewable energy sources, and nearly all of them in the focus groups said that the cost for parts of the grid upgraded to enable greater integration of renewable energy sources should be distributed to all customers. Although PV continued to be the most commonly mentioned source of renewable energy, customers also indicated support for the electric companies to consider energy generation through wind power, biomass, geothermal, and wave energy, among others. Greater integration of renewable sources was felt to have many benefits including protecting the environment but, more importantly, potentially leading to more affordable electricity rates and more reliable delivery of electricity. And because everyone may benefit, everyone should pay.

> **"Everyone should share in the cost because we will all benefit from it." – Hawai'i Electric Light Customer**

> **"I think it should be spread out among everybody because we will all benefit from it." – Hawai'i Electric Light Customer**

> **"I think that everyone should pay for it because, in the long haul, it will benefit everybody and not just those who have PV." – Hawaiian Electric Customer**

> **"Everyone should pay if everyone will have access to the excess energy that they create. But if it benefitted only PV owners, then only PV owners should pay. I don't think everyone should pay if it benefits only a portion of the population." – Hawaiian Electric Customer**

> **"If there were better infrastructure that allowed for more renewable energy it would be beneficial to everyone, so if there's a cost associated with better infrastructure then I think the cost should go to everyone." – Maui Electric Customer**

Only PV owners should pay for additional grid upgrades caused by PV

However, non-PV customers would be less willing to pay for additional grid upgrades caused by PV. Some customers, all of them without PV systems, said that only PV owners should pay because, despite generating energy for the grid, they still need to maintain their fair share of being connected to the electric grid.

> **"For the people who have that solar electricity and they're paying that $20 a month, they got a really good deal. How do we get them to pay for this system? I'd like to see them contribute to the community in a meaningful way." – Hawai'i Electric Light Customer**

> **"This is just gut reaction, but if we compare the cost of generating the electricity to the cost of maintaining or updating the grid---the wires, the poles, the transformers, all of that---it just doesn't seem like the $18 that they pay covers that use, even though they are putting electricity back into the grid. And, so, they should pay for the upgrade, because that would only be fair." – Maui Electric Customer**

PV owners, and some without PV, felt differently. They talked about the initial investment they had to make in order to get their PV systems and, considering that PV owners generate electricity that is also distributed to non-PV owners, felt it would be unfair to place the burden of additional upgrades caused by PV only on them.

> **"I don't think the cost should only be on us, because you can't say that only I am benefitting from that part of the upgrade, since Hawaiian Electric uses the electricity that I generate to power other homes and not just mine. I don't think that would be very fair." – Hawaiian Electric Customer**

Only EV owners should pay for parts of the grid upgraded for EVs

On the other hand, all were in agreement and are unwilling to pay for grid upgrades to accommodate electric vehicle (EV) charging demands. When asked if only EV owners or if everyone should pay for parts of the grid upgraded for electric vehicles, nearly all of the customers in the focus groups said that only EV owners should pay. There is a perception that

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EV owners already receive many benefits, such as free charging at certain locations, without giving anything in return. While customers conceded the environmental benefits of EVs, they are not aware of any potential for lower electric rates or more reliable electric service stemming from EV usage that would justify charging everyone for parts of the grid upgraded for EVs.

> **"Only EV owners should pay. I don't think that they are contributing anything to the grid and the upgrade would only benefit them, so they should pay. It would be the fair thing to do." – Hawaiian Electric Customer**

> **"I think that only EV purchasers should pay for that part of the upgrade. At our hotel, there is a charging station. There are employees who have electric vehicles who charge at the charging station for free. I would love to be able to go to the hotel and have them fill my car with gas for free, but that doesn't happen. If you use it, you should pay for it." – Maui Electric Customer**

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Appendices

APPENDIX A

Date

Name
Title
Company
Address
City, State, ZIP

Dear Name:

At Hawaiian Electric, we are committed to preserving all that makes our islands so special. One of the ways we are accomplishing this is by working hard to modernize our electric grid. In an effort to better understand the desired overall features and benefits of a grid modernization program, Hawaiian Electric has commissioned Ward Research, a well-respected market research firm in Honolulu, to conduct a series of one-on-one interviews among key stakeholders across the Islands. You are viewed as a key stakeholder, your opinions are valuable, and your perspective will be instrumental in assisting us in this evaluation process.

At this time, we are asking if you would be willing to participate in an interview, lasting approximately (TBD) minutes, arranged at a time and location that is most convenient for you. In recognition of your time and thought, a (TBD) donation will be made to a non-profit organization of your choice.

A staff member from Ward Research will be contacting you in the next several days to follow up and, if you agree, to schedule an appointment with Rebecca S. Ward, President of Ward Research, or Ty Law, Project Director at Ward Research. All responses will be treated in strict confidence; information derived from the interviews will not be attributed to individual participants but will be reported only in combination with the responses of others.

If you have any questions, please call Wade Shimoda, Customer Research Division at Hawaiian Electric, at (808) 543-4786. We sincerely hope that you will invest the time to assist us. We appreciate your consideration and thank you, in advance, for your participation.

Sincerely,

George Willoughby, Ph.D.
Director, Customer Research

WARD RESEARCH
INCORPORATED

Grid Modernization Study
Stakeholders – Interview Guide

Let me start by saying that this is a project we are working on for Hawaiian Electric; gathering the input of stakeholders to help inform their Grid Modernization planning. Your responses will remain anonymous, reported only in combination with the responses of others. (*Key on infrastructure/grid adaptations*)

Big Picture

1. From a big picture perspective, where do you see Hawaii going with the future of energy?

    a. How do you see HECO fitting in that future?

Electric Grid

2. How would you describe today's electric grid?

    a. What is the condition or the status of the grid?

    b. What should today's electric grid be able to do, or what are the minimum functions customers, such as you, should expect?

3. There has been a lot of talk lately about grid modernization, what does that term mean to you?

    a. From your perspective, what should a modernized grid be able to do that our grid currently cannot do or won't support?

    b. Are there other benefits that you think a modernized grid should bring to Hawaii?

4. I don't know if you would answer this differently, but what should a modernized grid be able to do in your industry?

    a. What other kinds of things would be important in grid design, or what else should this grid be able to deliver.

5. Is the future reliability of the grid a concern for you? If so, in what way?

Reliability and Trade-offs

6. (FOR CUSTOMERS/LARGE ORGS) How important is the reliability of electricity for your operations?

    a. Some stakeholders would accept a slightly less reliable grid in order to reduce costs. Others would not make that trade-off, saying grid reliability has to be the priority. Where do you stand?

7. How do you rate the reliability of electricity today?

    a. (PROBE) Why do you say that?

    b. Are there steps (e.g. backup generator, battery) taken on your side to maintain reliability for your operations?

Aided probes if not already discussed:

Battery and Storage

8. One view of the future suggests that we can produce an excess of energy during the daylight hours. If properly stored and managed in batteries, this excess can help provide energy throughout the evening.

    a. Should HECO be responsible for building the battery system to store the excess produced and deliver energy to customers? And if so, who should pay for it?

    b. Or should commercial customers become responsible for their own energy, and maintain their own storage system?

        i. In that scenario, do you see HECO as a backup, standing by with emergency generation?

Other discussion topics

9. What are your thoughts about variable pricing for electricity, such as Time of Use pricing that incentivizes use at times of day when the supply of electric power is the greatest?

    b. Is this something the grid (and associated meters and hardware) should provide for?

    c. Do you envision a time in the future when customers would check pricing and adjust their usage based on it? Would there be any difference amongst residential or commercial customers?

10. Was there anything you wanted to say about grid modernization since you knew we were going to be talking about it today?

11. Is there anything Hawaiian Electric can do for you?

APPENDIX C

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DISCUSSION OUTLINE: REVISED
GRID MODERNIZATION FOCUS GROUPS
WR7190

I. Introduction 10 min

Introduction of moderator, research firm, general purpose of the research
Ground rules
Introduction of participants to include:

- ✓ Occupation
- ✓ Area of residence on island and type of housing
- ✓ Number in household

II. Priorities 20min

DISTRIBUTE QUESTIONNAIRE: One of the first things I would like you to do is to fill out a really brief questionnaire. I'd like you to imagine that you were asked by Hawaiian Electric to help them establish some priorities to these factors, recognizing that all of them are important and they can't walk away from any of them:

- Reliable Delivery of Electricity
- Affordable Rates
- Renewable Clean Energy

- How many rated reliable delivery of electricity the highest priority? What about affordable rates? And what about renewable clean energy?
- ASK ABOUT EACH: Why do you say that? What makes it a priority over the other two? What factors did you consider when assessing the priorities?
- What does "reliable delivery of electricity" mean to you? Do you think the reliability of your electric service is adequate today? Do you think it will remain adequate for the future? Explain.

- Would you be willing to accept less reliable delivery of electricity if it also means more affordable rates? Why do you say that? How do you define "less reliable delivery of electricity"?
- Would you be willing to pay more if it also means a more reliable electric delivery system? Why do you say that? How much more?
- What are you seeing or hearing about Hawaiian Electric when it comes to renewable clean energy? What is Hawaiian Electric doing? Is Hawaiian Electric doing enough?
- Would you be willing to pay more on your electric bill if it also means greater adoption of renewable clean energy? Why do you say that? How much more?

III. The Electric Grid 20min

Let's move on now to a slightly different topic.

- What, if anything, have you seen or heard about the status of the electric grid? Where did you see or hear that information?
- How would you rate the current status of the electric grid? Why do you say that?
- What does a "modern" electric grid mean to you? What is it?
- What do you expect from a "modern" grid? Tell me some characteristics of a modern electric grid. What should it be able to do?
- What are the benefits of a modern electric grid?
- What are the advantages and disadvantages of modernizing the electric grid?
- Is modernizing the electric grid an important thing for Hawaiian Electric to do? Should Hawaiian Electric "modernize" the grid? Does it need to be "modernized"? Why do you say that?

IV. Challenges of Maintaining the Stability of the Grid 15min

What I would like to do now is to share with you some information about the electric grid.

SHOW:

Maintaining Safe and Reliable Energy for Customers

Managing a Two-Way System to Integrate More Renewable Energy

FOR EACH, ASK:

- Was there any new information for you in these videos? What does it tell you about the electric grid?
- Is this important information for consumers to receive? Why is that?

V. Reactions to Future Scenarios

We've all heard a lot about energy storage. And the video made reference to excess energy in the system, sometimes posing a safety problem.

- So when technology is at a place where this storage is cost effective and reliable, who should be responsible for that energy storage? Should it be Hawaiian Electric? Customers? both?
- If Hawaiian Electric should be responsible, there are different ways they might do this. For example, they could build storage facilities, so that when they need more power, they could use that source instead of revving up a generator. Or, they might ask customers to let them install storage "units" on the customer's property, and they could access it when they need more power. What are your thoughts about these? What questions would you ask --- what would you want to know about these? (PROBE TO DISCUSS EACH OF THE OPTIONS)

VI. Costs and Implementation 20min

- Who should pay to modernize the grid? Why do you say that?
- Would you accept a rate increase to modernize the grid? How much of an increase? What about a 5%, 10%, 15% increase to your current bill?
- Would you prefer a broad and aggressive implementation of new technology (higher costs upfront, but more affordable in the long-run) or gradual/steady implementation?
- Do you believe that it is fair that costs to upgrade/modernize the grid be spread evenly across the rate base to reduce bill impacts? Or should costs be charged only to customers that will directly benefit from the upgrades?
- Do you believe that it is fair that ALL customers pay for the cost to adopt rooftop PV into the grid? Or should it be paid for by ONLY customers that have PV?
- What about electric vehicles? Should the grid be designed to charge electric vehicles? Do you believe that it is fair that ALL customers pay for the cost of upgrading the grid to charge electric vehicles? Or should it be paid for by ONLY customers that have electric vehicles?

VI. Thank you and close 5min

Is there anything else you would like to say about the things we discussed today?

Appendix C: Proposed Grid Modernization Net Benefits Assessment

Prepared by Energy and Environmental Economics, Inc.

Proposed Grid Modernization Net Benefits Assessment

Summary of Methodology

June 30, 2017

Energy+Environmental Economics

Proposed Grid Modernization Net Benefits Assessment

Summary of Methodology

June 30, 2017

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TABLE OF CONTENTS

SECTION 1: INTRODUCTION AND SCOPE OF WORK

Q1. WHAT WAS ENERGY AND ENVIRONMENTAL ECONOMICS INC (E3) SCOPE OF WORK?

A1. E3 was asked to work together with the Companies and a team of consultants (EPRI, Newport Consulting and Enernex) to comply with the commission guidance given in Order 34281[1].

Specifically, we were asked to review the Companies existing benefits evaluation methodology and propose a new methodology that both responds to the Commission's guidance and can be used to evaluate new grid modernization proposals under a range of future scenarios.

Because the Companies are not filing a specific plan on June 30, 2017, this document does not contain specific costs and benefits of a proposal. Instead, the proposed evaluation methodology described here, or a modified version of it that incorporates feedback from the stakeholder process, will be used to evaluate a specific grid modernization proposal and accompany that proposal along with requests for funding.

Q2. CAN YOU BRIEFLY OUTLINE THE EVALUATION PROCESS YOU ARE PROPOSING?

A2. Yes. The process has four steps:

1. Categorize each of the proposed expenditures in the grid modernization plan according to the main reason they are needed.

   a. **Standards and Safety Compliance**

      Expenditures that are primarily **needed to ensure reliable operations, or comply with service quality and safety standards** in a grid with much

[1] PUC Order No. 34281, "Dismissing Application with Prejudice and Providing Guidance for Developing a Grid Modernization Strategy", Docket No. 2016-0087, dated January 4th, 2017.

higher levels of renewable resources connected behind and in front of the customer meter.

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 distributed energy resources (DER).

c. **Net Benefits**

Expenditures that The Companies identify as needed primarily because they would directly provide net benefits to customers, or enable renewables or DER to **lower the costs** of electricity service. Renewables or DER may lower costs by displacing grid services that would have otherwise been offered by a more expensive source.

d. **Self-Supporting**

Expenditures that would be **paid for directly by customers participating in DER programs** via a self-supporting margin neutral DER tariff[2], and programs, including demand response and others that could be developed in the future, such as Real Time Pricing that require advanced metering capabilities, for example.

2. Develop an appropriate evaluation methodology for the proposed expenditures in each of the four categories.

3. Describe the common assumptions used to estimate benefits by category.

4. Apply methodology, assumptions, and cost estimates to proposed expenditures to develop transparent estimates of net costs and benefits for each part of the proposed plan.

[2] See Section 2, pg. 13 for a detailed explanation of margin neutral rates

Q3. ARE YOU RESPONSIBLE FOR DETERMINING WHICH CATEGORY EACH OF THE PROPOSED EXPENDITURES FITS INTO AND FOR DETERMINING COSTS?

A3. No, the Companies are responsible for placing each of the proposed expenditures into a category and for providing plausible estimates of both capital costs and operational expenses suitable for estimating and developing plausible estimates of net costs or benefits of the proposed plan. See Section 8 of the Grid Modernization Strategy document for a description of that process.

Q4. WHAT ARE THE BENEFITS OF UNPACKING THE GRID MODERNIZATION STRATEGY INTO THE CATEGORIES YOU HAVE PROPOSED?

A4. There are three benefits:

1. It makes the grid modernization strategy and its potential cost impacts more transparent, which facilitates better feedback from stakeholders and from the Commission.

2. The decomposition of grid modernization expenditures into its component parts also makes the methodology better matched with specific evaluation methods. The evaluation method used for a specific investment depends on the category it falls in.

3. Finally, it allows us to evaluate those applications that are required for the integration and utilization of DER that will ultimately enable *customer facing programs*, as well as those that provide net benefits to all customers and support energy policy in a resource planning context.

We hope it helps stakeholders, regulators and policy makers understand what they are being asked to pay for and what they can expect the investment to deliver.

Q5. DO EACH OF THE EXPENDITURE CATEGORIES REQUIRE A COST EFFECTIVENESS EVALUATION?

A5. There are different screening and evaluation approaches for each category.

Proposed expenditures in the standards and safety compliance category will be evaluated on a lowest reasonable cost basis – standard practice for these types of investment in Hawaii[3]. The Companies must demonstrate that the proposed expenditures provide the lowest reasonable cost way to comply with the standard, such that ratepayers are provided with best value. If these expenditures also provide benefits, then the companies must show that they have minimized net costs.

Grid modernization investments that enable customer DER interconnection to meet policy objectives are expected to be considered in the overall resource planning process (PSIP) that assesses the optimal mix of large scale renewables and distributed resources on a prospective basis as described under the Net Benefits category. However, if policy decisions or customer adoption of DER under approved Tariff Riders necessitates grid investments (net of DER offsetting services), these will be evaluated on a lowest reasonable cost basis (the Policy Compliance category).

The category of investments to be paid for entirely by participating DER customers (Self-Supporting) does not require a cost effectiveness evaluation. We are assuming that customers voluntarily choose to pay the full incremental costs of the DER expenditures and they are served on margin and revenue neutral rates so there is there is no impact on other customers caused by either expenditure by the utility or the customers' participation in the DER program.

Q6. DO ALL EXPENDITURES IN CATEGORIES 1 THROUGH 3, (STANDARDS AND SAFETY, POLICY, OR NET BENEFITS) REQUIRE THAT BENEFITS BE GREATER THAN COSTS?

A6. No. Only for proposed expenditures that are intended to reduce costs for electricity consumers (Net Benefits), is there a need to demonstrate plausible estimates of net lifetime benefits. If the Companies believe that a project in the Net Benefits category

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[3] This type of approach is described as least cost-best fit in other jurisdictions, and is referred to as such in much of the grid modernization literature.

should proceed despite having quantified benefits that are lower than costs, the Companies would provide additional justification for the project.

Proposed expenditures in the Standards and Safety and the Policy Compliance categories are evaluated based on lowest reasonable cost criteria and do not need to pass a positive net benefits test.

Q7. ARE THERE ANY GUIDELINES THAT THE COMMISSION SHOULD USE TO EVALUATE THE PROPOSED EXPENDITURES NECESSARY TO MEET STANDARDS, MAINTAIN SAFETY, AND COMPLY WITH POLICY?

A7. Yes. We are proposing that standards, safety, and policy compliance expenditures be assessed as appropriate, and made at least-cost to consumers. That is, we will estimate costs and identify use for expenditures in both categories (a) and (b) described in Q2. The Companies will have the traditional burden of proving that the expenditures proposed are lowest reasonable cost.

Q8. YOU ARE ASSUMING THAT THE SELF-SUPPORTING CATEGORY OF EXPENDITURES ARE SERVED ON MARGIN NEUTRAL RATE DESIGNS; CAN YOU DESCRIBE WHAT THIS IS AND WHY YOU NEED TO MAKE THAT ASSUMPTION?

A8. A margin neutral rate separates fixed from variable costs so that customers who are paid incentives for participating in a DER program and as a result modify their demand, are not paid once for the value of their services to the grid and again by reducing their bills.

This assumption is important, because for the company's expenditures in the self-supporting category to be cost-effective the following conditions must hold. First, participants should pay for the full incremental costs of their share of the grid modernization investments; and second, they should not receive subsidies from non-participating customers. If these conditions are met, they can receive multiple "stacked" benefits by avoiding ancillary services, energy and system and local needs for capacity if the customer qualifies for the services and they can be provided simultaneously.

Q9. WHAT IS LINK BETWEEN YOUR PSIP PLANS AND THE EVALUATION METHODOLOGY YOU ARE PROPOSING TO USE IN THIS FILING?

A9. For the PSIP work, E3 used a transparent set of input data and clearly defined range of assumptions provided by the Companies and stakeholders to develop least cost RPS compliant long term plans using its RESOLVE expansion planning model. These plans served as a starting point for the Companies to refine the plans based on subsequent more detailed analysis that was described in the PSIP December 2016 filing.

In our recommended evaluation process here, we are proposing to use the same model (or comparable) to test the cost effectiveness of the expenditures proposed in the Net Benefits category on a prospective basis as part of resource planning process such as PSIP. This way the net value from a forecast mix of DER may be assessed against the cost of enabling grid investments to yield the net benefit. For example, benefits and grid costs of an increased adoption of DERs due to policy decisions and customer choices can be assessed. The benefits would be derived from the difference between a base case plan and one that includes the grid modernization project(s) and their ability to enable a more valuable DER portfolio. The benefits would also reflect the impact of the grid modernization projects on the transmission and distribution investments previously described by the Companies in Appendix N of the December 2016 PSIP filing.

Q10. DOES YOUR PROPOSED EVALUATION METHODOLOGY ACCOUNT FOR ANY LOCAL BENEFITS OFFERED BY DER RESOURCES?

A10. Yes, we have worked with the Companies planning teams to incorporate preliminary estimates of potential cost savings of having DER resources provide local grid services into the evaluation methodology. Note that in the DR docket filing[4], the Companies defined DR benefits as system level only and parameterized the benefits using the PSIP filing results. The methodology that we propose here is consistent with but expands that approach in two ways:

1. We propose to use estimates of both **local** and system (PSIP) benefits to test the net benefits of DER less the required grid modernization expenditures. It is important to

[4] Docket No. 2015-0412 - Application of Hawaiian Electric Companies for Approval of Demand Response Program Portfolio Tariff Structure Revised Demand Response Portfolio, Exhibit 1 at 2, dated December 30th, 2015.

note that grid modernization investments that enable DER value realization should be considered only in the context of whether the DER creates net benefits. It is not appropriate to evaluate DER enabling investments independently of the net benefit of the DER. If not for the DER, these investments would not be needed.

2. We propose to use an **integrated** approach, where DER resources net of their local benefits, are selected by an integrated resource planning model that selects a least cost combination of both system connected and local DER resources.

Q11. PLEASE BRIEFLY DESCRIBE THE PROCESS YOU ARE USING TO WORK WITH THE CONSULTING AND COMPANY GRID MODERNIZATION TEAM?

A11. The process we are using is collaborative and iterative, relying on the evaluation process to help refine the proposal(s). The consulting and company teams will develop a range of potential plans and then use the evaluation process to assure that the plans are as cost effective as possible without jeopardizing reliability, safety or policy compliance.

Q12. HOW IS THIS DOCUMENT ORGANIZED?

A12. In Section 2 we describe what margin neutral rates are and why we assume margin neutral rates in the grid modernization evaluation. The concept is demonstrated through a simple example rate structure applied to Hawaiian Electric's existing Schedule J, General Service Demand, rate.

In Section 3 we describe the grid modernization evaluation approach used by other jurisdictions and the "stacked benefits" DER focused approach that is enabled by some portions of the grid modernization expenditures.

In Section 4 we describe the methodology that we propose to use to develop estimates of benefits for the Safety Compliance, Policy Compliance and Net Benefits proposed expenditures.

Finally, in Section 5, we develop a hypothetical simple grid modernization proposal as an example of the proposed evaluation methodology.

SECTION 2: DESCRIPTION OF MARGIN NEUTRAL RATES ASSUMED IN GRID MODERNIZATION EVALUATION

Q13. THE GRID MODERNIZATION METHODOLOGY ASSUMES THAT CUSTOMERS ARE SERVED ON "MARGIN NEUTRAL" RATES. PLEASE DEFINE THIS TERM.

A13. Margin neutral rates leave the utility with the same margin regardless of the customers' usage, where margin is defined as the revenue above its variable costs that contributes to the utilities recovery of its fixed costs. DER customers served on margin neutral rates can be paid the incremental avoided costs of the grid services that they provide and leave the utility and all other non-participating customers no worse off. In this context, distributed energy resources (DER) include all customer sided technologies that provide energy services to either directly to the customer, the grid, or both. These can include rooftop PV and other types of customer sided generation, storage including thermal storage, responsive load controls, and energy efficiency measures.

Margin neutrality can be accomplished when DER customers, either directly or through third party aggregators, are served on rate structures and programs that clearly separate fixed from variable costs. The fixed costs typically include several components: the basic costs to interconnect and serve a customer (customer costs), the fixed production, transmission and distribution costs of building and reliability operating the grid, and the costs of providing ancillary services required to support the grid. The Companies have defined a set of four ancillary services made available for customer participation through proposed new rate riders (grid access fees)[5]. Variable costs include the costs of fuel and energy purchased on a per-kWh basis.

Although margin neutral rates are intended to facilitate fair customer participation in DER programs, these rates could also be available to all other customers should they wish to switch from their existing rate.

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[5] Docket No. 2015-0412 - Application of Hawaiian Electric Companies for Approval of Demand Response Program Portfolio Tariff Structure Revised Demand Response Portfolio, Exhibit 1 at 2, dated December 30th, 2015.

Q14. WHY IS IT NECESSARY TO ASSUME THAT DER PARTICIPANTS ARE SERVED ON MARGIN NEUTRAL RATES IN YOUR EVALUATION METHODOLOGY?

A14. There are two reasons:

First, it allows us to exempt all grid modernization expenditures in the Self-Supporting category from having to show positive net benefits as long as these customers are charged for the full incremental costs of the services that the utility provides them. Their participation in DER programs will leave both the utility and non-participating customers no worse off.

Second, it avoids a difficult cost allocation and equity problem that is emerging in many jurisdictions. Hawaii, like other leading DER jurisdictions, focuses on using the Total Resource Cost test in planning and resource evaluation. This test ignores potential transfers between participating and non-participating customers, which has caused equity issues in jurisdictions with Net Energy Metering and various forms of direct access or community choice aggregation. DER participants served on margin neutral rates, however, do not transfer embedded costs to non-participants, and as long as they are paid no more than the costs that they avoid for their grid services provided, will pass the TRC cost test and lower rates for all customers.

Q15. CAN YOU PROVIDE AN ILLUSTRATIVE EXAMPLE OF A MARGIN NEUTRAL RATE AND COMPARE IT TO AN EXISTING RATE?

A15. Yes. In the New York Reforming the Energy Vision proceedings, the Smart Home Rate pilot has been proposed for Consolidated Edison and Orange & Rockland, which includes margin neutral rate designs. These separate fixed and variable charges to cover the customers' costs of service. In its simplest form, a margin neutral rate includes three parts:

1. Customer Costs ($/Customer-Month)
2. Grid Access Fee ($/KW-Month)
3. Energy Charge (TOU rate)

The Customer Costs and the Grid Access Fees are fixed costs that have already been committed to by the utility and are based on the utility embedded customer and grid costs. The Energy Charge would be based on variable operational costs. It may reflect future costs that can be avoided such as capacity and ancillary services; however, for the purposes of this simple example, we assume that those costs are not embedded within the rate structure. The grid services provided by the customer would be compensated via utility program payments outside of the rate structure.

For illustration and comparison, Hawaiian Electric's existing Schedule J, General Service Demand, is already a 3-part rate design that can readily be adapted to be a margin neutral rate. A comparison is shown below:[6]

Monthly Rates	Existing		Illustrative
1. Customer	$77.00/acct.	Customer	$147.50/acct.
2. Demand	$11.69/kW	Grid Access	$17.70/kW
3. Energy (a)	16.973¢/kWh	Energy (a)	14.676¢/kWh

An average customer within the rate class with a billed demand of 80 kW/month and energy usage of 23,978 kWh/month would have a bill of $5,085 plus surcharges under either rate. Note that the existing customer and grid access costs are substantially below their full embedded costs and the energy charge is above the average variable costs of energy. This creates an incentive for all customers served under the existing rate schedule to reduce their energy use and shift embedded costs to other customers.

For example, if a customer were to install behind the meter generation and reduce their net energy consumption taken from the grid by half, but maintained a similar demand, the utility's costs of serving them would be reduced by $1,760 (14.676¢/kWh X 11,989 kWh) but the customer's bill would be reduced by $2035 (16.9734¢/kWh X 11989 kWh). The approximately $275/month difference between incremental cost reduction for the utility and bill reduction for the utility is a cost that is ultimately covered by other non-participating customers.

The illustrative and comparative example for residential customers is more pronounced. Hawaiian Electric's existing Schedule R, Residential, is a 2-part rate design with most fixed costs recovered in the kWh energy rate. A comparison with an illustrative revenue neutral rate is shown below:[7]

Monthly Rates	Existing		Illustrative
1. Customer	9.00	Customer	$23.50/acct.
2. Demand	n/a	Grid Access	$7.87/kW
3. Energy–Fuel (a)	13.6062¢/kWh	Energy-Fuel (a)	13.6062¢/kWh

[6] Based on Hawaiian Electric 2011 Test Year, Docket No. 2010-0080, Hawaiian Electric Final Revised Tariff Sheets and Rate Schedules, dated July 24, 2012, Exhibit B, Att 1, p. 41 and Exhibit C, p. 79.

[7] Ibid., Based on Exhibit B, Att 1, p. 5 and Exhibit C, p. 79.

Energy–Non-Fuel T1 (b)	8.1034¢/kWh	Energy-Non-Fuel (b)	0.727¢/kWh
Energy-Non-Fuel T2 (c)	9.2569¢/kWh		

An average customer with a billed demand of 4.7 kW/month and energy usage of 651 kWh/month, where tier 1 for non-fuel energy charges is 350 kWh, would have a bill of $154 plus surcharges under either rate. In the existing case, the rate is calculated as $9 + 13.6062¢/kWh X 651 kWh/month + 8.1034¢/kWh X 350 kWh/month + 9.2569¢/kWh X 301 kWh/month = $153.8/month. In the illustrative case the rate is calculated as $23.5 + $7.87/kW X 4.7kW/month + 13.6062¢/kWh X 651 kWh/month + 0.727¢/kWh X 651 kWh/month = $153.8/month. However, under existing rates, a partial requirement customer with similar demand, but half the energy usage would result in a bill reduction greater than the incremental cost reduction to the utility of $26/month that is ultimately covered by other non-participating customers.

(a) Although illustrated as a flat rate, margin neutral rates would most likely have a time varying or TOU structure.
(b) First 350 kWh. Next 850 kWh is an additional 1.1535¢/kWh, then 3.0309¢/kWh over 1200 kWh.

Q16. CAN YOU DESCRIBE HOW A SIMPLE MARGIN NEUTRAL RATE SIMPLIFIES THE EVALUATION PROCESS?

A16. Yes. A commercial customer invests in cold storage to provide grid services to the Companies. To participate directly in the DER and DR programs offered under the proposed tariff riders, we assume for cost effectiveness evaluation that the customer must also take service under a margin neutral rate.

The Customer Charges and the Grid Access Fees are based on the embedded customer and grid service related costs for commercial customers. The customer would also be subject to any non-bypassable charges such as the Green Infrastructure Fee (GIF).

The customer is one of the winning bidders selected through a Request for Proposal (RFP) process to provide both Capacity and Regulation grid services. To be eligible to receive these services, the customer must pay for a new AMI meter that supports the communication and dispatch systems required to implement the newly proposed grid services. If the customer wins the bid that is capped at the avoided costs of the services provided, the customer provides net benefits to all ratepayers and no cost-effectiveness test is needed for the expenditures made on behalf of the customer. Moreover, no cost allocation or new equity issues are introduced by customer choice.

Note, however that there is still a need to look on a prospective basis at the value of investing in the grid to DER interconnection and operations in the future. We are

proposing that these investments be considered in the PSIP process or in another utility long term planning update, where they can be fairly evaluated, along with a myriad of competing bulk power alternatives.

Q17. CAN THIS COST EVALUATION METHODOLOGY AND REVENUE NEUTRAL RATE CONCEPT BE APPLIED TO COSTS FOR RECOVERY VIA REGULAR OR INTERIM SURCHARGES?

A17. Yes. To the extent that is it practical, costs that vary with kWh usage should be based on a kWh surcharge and costs that do not vary with kWh usage, or determined by law or Commission order to be non-bypassable, could be based on fixed, demand, and/or minimum, surcharges. For example, the GIF, which is authorized and non-bypassable by State law[8], is assessed to customers on a fixed charge basis. The Public Benefits Fund, also policy driven but currently a kWh-based surcharge, could be similarly evaluated.

Q18. IS YOUR MARGIN NEUTRAL RATE CONSISTENT WITH THE COMPANIES' BROADER OBJECTIVES IN THE RETAIL PRICING OF SERVICES PROVIDED TO CUSTOMERS?

A18. Yes it is. Based on my discussions with Company representatives, they seek to implement longer term sustainable pricing structures that provide customer choice and price signals that encourage efficient use of the electric system. Customers who choose to provide a portion of their electricity needs should only pay for the grid services (i.e., energy, delivery and ancillary) that they receive from the utility. To achieve this goal, the Companies need to unbundle their costs for all "partial requirements" customers. Such pricing should be based on cost causation as informed by cost of service studies in rate cases. Costs that are caused by the number of customers should be priced on a per customer basis. Costs that are caused by peak loads should be priced on a per-kW of peak load basis. Costs that are caused by energy consumption should be priced on a per-kWh basis.

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[8] Hawai'i Revised Statutes § 269-166 (2013)

Q19. HOW SHOULD THE COMPANIES RECOVER THE COST OF GRID MODERNIZATION?

A19. Costs should be recovered from customers who benefit from grid modernization based on cost causation. As described earlier, costs to meet reliability and safety standards, support of public policy or allow the Companies to provide services at a lower net cost that benefit all customers should be recovered from all customers. Costs that enable participation in DER and DR programs or enhanced services should be recovered on an "opt-in" basis from those participants that directly benefit from those investments[9].

Q20. ARE THE COMPANIES PROPOSING NEW RETAIL RATE DESIGNS?

A20. Not in this proceeding. However, the Companies feel that cost recovery of grid modernization investments is intertwined with similar issues in the Distributed Energy Resources (DER) proceeding, and the Demand Response (DR) proceedings[10]. As such, the Companies will examine, collaborate with other stakeholders and, as appropriate, propose new rate designs in these concurrent proceedings. The Commission, in its DER procedural order[11], had established the Market Track Issues and the timing of the related procedural steps. The Initial Statement of Position on Market Track issues including proposed tariff language, if applicable, is due no later than August 6, 2018 and the Final Statement of Position is due no later than September 17, 2018. In addition, the Interim Residential Time-of-Use Service (TOU-RI) annual report is due no later than January 31, 2018.

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[9] Depending on the program structure, participants could include customers and/or DER vendors serving those customers.

[10] Docket No. 2014-0192, Distributed Energy Resources Policies, dated September 16th, 2016, and Docket No. 2015-0412, Demand Response Portfolio Structure, dated December 30th, 2015.

[11] PUC Order No. 34206, "Establishing Statement of Issues and Procedural Schedule for Phase 2", Docket No. 2014-0192, dated December 9th, 2016.

Q21. ARE THERE ANY OTHER DOCKETS THAT THE COMPANIES WILL BE PURSUING CHANGES TO RETAIL RATE DESIGNS?

A21. The Companies are pursuing changes to retail rates in general rate cases. In the pending general rate cases for Hawaiian Electric and Hawai'i Electric Light[12], changes were proposed to rates for the customer, minimum and demand charges to better align with cost causation. No new rate designs were proposed in these rate cases as the Companies proposed that new rate designs, including time-of-use[13], to be addressed in the DER proceedings. As rate designs are approved by the Commission in the DER proceedings, this will inform pending and future rate cases.

Q22. HOW ARE CUSTOMERS CURRENTLY COMPENSATED FOR GRID SERVICES THAT THEY PROVIDE TO THE UTILITY?

A22. There are two ways that customers are compensated: (1) retail rates and (2) programs (i.e., DER and DR). For example, TOU-RI customers are "credited" for load shift by arbitraging the price differentials in the different time periods and Customer Grid Supply (CGS) customers are credited for energy at the CGS program rate. The DR program will use RFPs to minimize costs and have avoided cost based capped values of customer-provided grid services.

The relationship between retail rates and DR compensation needs to be carefully synchronized to properly compensate for customers for services that they provide to the grid (e.g., avoid over-compensation by allowing customers to arbitrage TOU rates while receiving DR compensation for the same services). The Companies are in the process of implementing the Demonstration Phase of the proposed DR program for capacity and load shift, regulating reserve and fast frequency response grid services. For the purpose of prospective grid modernization expenditures that would enable a larger and more valuable DER portfolio, we are assuming that customers are served on margin neutral rate designs where there is cost shifting that needs to be accounted for the evaluation.

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[12] Docket No. 2016-0325 for Hawaiian Electric 2017 test year, dated October 28th, 2016, and Docket 2015-0170 for Hawai'i Electric Light 2016 test year, dated June 17th, 2015.

[13] Hawai'i Electric Light 2016 test year rate case, Docket No. 2015-0170, Hawai'i Electric Light T-22 at 26, dated June 17th, 2015.

Q23. ARE THERE OTHER JURISDICTIONS WITH SIMILAR MARGIN NEUTRAL RATE STRUCTURES?

A23. Yes, Consolidated Edison and Orange & Rockland recently proposed a Smart Home Rate (SHR) program that has a three-part margin neutral structure similar to those described above. It is a voluntary rate designed for customers to integrate a variety of DER resources into the grid and to provide grid services. The utilities offer the following rationale for the design of the rates:

> *At a basic level, SHRs should adhere to the Commission's rate design principles in the Track Two Order. Beginning with cost causation, these principles reflect the balance that should be achieved by an SHR. These new rate designs should be developed to appropriately recover the costs incurred to serve an SHR customer with a view toward the long-term economic sustainability of the rate structure. Additionally, these rates should encourage policy and market outcomes, provide policy transparency, and promote economically efficient and market-enabled decision making. Pilot programs will provide important insights, and provide for a gradual approach, which is yet another Commission and rate design tenet. [p 5 Con Ed and O&R Demonstration Project]*

SHR participants can select between two rate options, shown in Table 1; both options, however reflect the following cost components (pp 8-9 of above report).

Table 1. SHR rates from Con Ed and O&R Demonstration Project

Cost components	**Unit**	**Rate components**	
		Option A	**Option B**
Energy production (supply)	kWh	Hourly supply charge	
Bulk Transmission capacity (zonal congestion portion)	kWh	Hourly congestion charge	
Bulk ancillary services	kWh	Flat charge for bulk ancillary services	
Embedded Transmission costs	kW	Flat non-coincident daily demand charge (on maximum interval excluding night time hours)	Monthly subscription for preselected kW
Embedded Distribution costs	kW		

Generation capacity [12]	kW	Flat coincident demand event charge (on maximum interval during the event, incremental to flat demand charge), event time windows vary by cost component	Variable coincident demand overage penalty (applied only during event hours to incremental demand above kW preselected by customer), event time windows vary by cost component
Forward Marginal Transmission capacity	kW		
Forward Marginal Distribution capacity	kW		
Customer connection cost	$/month	Fixed monthly customer charge	

In general, the multi-part rate design has been used for many years by the Companies and other utilities for commercial and industrial rate designs. Lower cost AMI meters, along with the rapid growth of distributed PV, has prompted a number of mainland utilities to start to increase customer charges and to begin to charge customers for their billing demand for residential customers. Both of these changes reflect a movement by utilities to start to move distribution costs, which are largely fixed and are long lived assets, to fixed and demand charges.

For example, Table 2 below shows a recent ACEEE study[14] showing utilities with residential 3 part rates.

[14] *Rate Design Matters: The Intersection of Residential Rate Design and Energy Efficiency,* Brendon Baatz March 2017 Report U1703

Table 2. Utilities with residential 3 part rates

Utility	State	Name	Customer charge ($/month)	Demand charge ($/kW)	Demand charge billing period	Volumetric rate
Alabama Power	AL	Time Advantage-Demand	$14.50	$1.50	All hours, all days	Varies, TOU
Arizona Public Service	AZ	Combined Advantage	$16.68	$13.50 (summer) $9.30 (winter)	Weekdays, 12–7 pm	Varies, TOU
UNS Electric	AZ	Residential Service Demand	$15.00	$5.10 (up to 7 kW) $7.10 (more than 7 kW)	Weekdays, 3–7 pm (summer); 6–9 am and 6–9 pm (winter)	6.61¢/kWh
Black Hills Energy	SD	Demand Service	$13.00	$8.10	All hours, all days	2.26¢/kWh
Black Hills Energy	WY	Demand Service	$15.50	$8.25	All hours, all days	6.43¢/kWh
Xcel Energy	CO	Demand Service	$12.25	$8.57 (summer) $6.59 (winter)	All hours, all days	1.74¢/kWh
Intermountain Rural Electric Association	CO	Residential Demand Metered	$10.00	$14/kW	All hours, all days	6.59¢/kWh
Glasgow Electric Board	KY	Residential Rate RS	$29.16	$11.33 (summer) $10.37 (winter)	Weekdays excluding holidays, 1–7 pm (summer); 6–10 am (winter)	Varies, TOU

SECTION 3: LITERATURE REVIEW OF GRID MODERNIZATION EVALUATION METHODOLOGY IN OTHER JURISDICTIONS

Q24. IS THERE AN INDUSTRY STANDARD GRID MODERNIZATION BENEFITS METHODOLOGY?

A24. The rapid evolution of the grid modernization applications and technology has precluded the establishment of a single comprehensive standard evaluation approach. We reviewed applications and decisions, from 5 jurisdictions, ranging from relatively simple proposals to install Advanced Metering Infrastructure (AMI) for select groups of customers to much more universal plans to upgrade the entire grid with distribution sensing and automation, Volt/VAR optimization, conservation voltage reduction and a variety of capabilities to support customer facing solutions.[15]

While many jurisdictions, such as Minnesota, New York, and Illinois, are in early stages of implementing grid modernization, California and Massachusetts are two leading jurisdictions moving forward with grid modernization and are on the leading edge of creating a rapidly evolving industry standard. Since there is no single standard grid modernization approach which encompasses all aspects of grid modernization, we will briefly summarize the grid modernization benefits approach undertaken by two large utilities in these leading jurisdictions: National Grid in Massachusetts, and San Diego Gas and Electric Company (SDG&E) in California.

Finally, we believe two other documents are directly responsive to the Commission Order 34281[16]. The first document is the Cost Effectiveness Framework (Section 3.4) from the Department of Energy's recently released Industry Draft of its *Modern Distribution Grid, Decision Guide, Volume III*, April 30, 2017. This document captures the latest effort by a consortium of jurisdictions in CA, DC, HI, MN & NY attempting to curate and define an industry standard.

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[15] We reviewed the following jurisdictions: California, Massachusetts, New York, Illinois, Minnesota

[16] PUC Order No. 34281, "Dismissing Application with Prejudice and Providing Guidance for Developing a Grid Modernization Strategy", Docket No. 2016-0087, dated January 4th, 2017.

The second document is the New York *Staff White Paper on Benefit-Cost Analysis in the Reforming Energy Vision Proceeding* (14-M-0101) July 1, 2015, which provides a relatively complete description of the many stacked benefits that might be available to DER resources enabled by some parts of grid modernization plans. This document carefully defines the broad range and types of potential benefits beyond those used in the more traditional Grid Modernization evaluation literature and describes a vision for a large and valuable DER market that is consistent with the following description written by the HPUC staff:

> *Hawaii's electric distribution systems physically interconnect a customer's premise to deliver grid-supplied power, as well as to accept customer-supplied power. Effectively, this opens the opportunity for the DER-equipped customer to become a "prosumer", that is a customer who both consumes or uses utility services and may also provide services to the utility. With significant penetration of renewable DER opening new opportunities for customer choice, the distribution system will need to function more like a multi-path transmission network rather than the radial delivery system of the past.*
>
> [Developing a State-of-the-Art Distribution System to Enable Clean Energy, Exhibit A: Commission's Inclinations on the Future of Hawaii's Electric Utilities (p 13)]

Q25. PLEASE SUMMARIZE THE GRID MODERNIZATION BENEFITS CALCULATED BY NATIONAL GRID IN MASSACHUSETTS.

A25. National Grid proposes one of the more advanced versions of a traditional benefits framework that focuses on direct grid benefits. The proposal includes multiple grid modernization approaches, including a scenario in which AMI meters are offered on a self-supporting opt-in basis instead of rolled out to all customers. Broadly speaking, the types of benefits which National Grid attributes to grid modernization are all related to improved transmission and distribution operations. The proposals include cost savings from system optimization of the grid, and reductions in power interruptions.[17]

The major benefits are attributed to: 1) Advanced monitoring, communications, and control systems on feeders to coordinate protective sectionalizing and reduce the scale and time to recovery of power interruptions; 2) Volt/VAR optimization to optimize

voltage and power factor of distribution circuits in real time to reduce losses; 3) Enhanced cybersecurity and training tools to reduce risk and optimize dispatch of repair crews as needed. Additionally, National Grid suggests that implementing AMI metering infrastructure can allow for more sophisticated time of use (TOU) rates, which can reduce bulk system peak period energy costs as customers shift energy usage away from peak price periods.

Q26. PLEASE SUMMARIZE THE GRID MODERNIZATION BENEFITS CALCULATED BY SAN DIEGO GAS AND ELECTRIC.

A26. The methodology applied in SDG&E's 2016 Smart Grid Annual Report was developed in accordance to EPRI's framework, presented in its 2010 report titled "Methodological Approach for Estimating the Benefits and Costs of Smart Grid Demonstration Projects" Accordingly, SDG&E's reported benefits are categorized into four bins: economic, environmental, social, or reliability.

The economic and reliability benefits are similar to those included by National Grid, with SDG&E also adding benefits due to grid modernization allowing for deferred transmission and distribution capital investments.

Environmental and social costs are estimated using a model SDG&E developed with the Environmental Defense Fund. This collaborative analysis focused on avoided emissions of nitrogen oxides, sulfur dioxide, greenhouse gases, as well as particulate matter. The estimates considered programs related to distributed and centralized renewable electricity generation, electric vehicle integration, as well as peak load reduction and load shifting. The quantified emissions were monetized using forecasted and existing emissions allowances prices.

Table 3 below summarizes the direct grid modernization benefits categories which National Grid and SDG&E include in their respective grid modernization filings.

Table 3. National Grid and SDG&E grid modernization benefits

	National Grid	San Diego Gas and Electric
Benefits	Direct (D) or Indirect (I)	Direct (D) or Indirect (I)
Bulk System Impacts		
Generation Capacity		
Energy	D	D
Transmission Capacity		D
Reduced Transmission Losses		

Avoided Ancillary Services		
T&D System Benefits		
Avoided Subtransmission Capacity		
Avoided Distribution Capacity		D
Avoided O&M	D	D
Avoided Distribution Losses	D	D
Avoided Restoration Costs	D	D
Avoided Customer Outage Costs**	D	D
External Benefits		
Avoided Emissions		I
Avoided Water Impacts		
Avoided Land Impacts		
Non-Energy Benefits		

* Direct benefits include benefits directly attributable to grid modernization (AMI infrastructure, distribution automation, etc.), whereas indirect benefits accrue from technologies which are in place because of grid modernization (e.g. automated controls allowing for increased DER penetration). Any benefits caused by higher amounts of DER would have to be netted against DER costs.

** Lawrence Berkeley National Laboratory's Value-of-Service Reliability model, described in a document titled "Estimated Value of Service Reliability for Electric Utility Customers in the United States," assembles data regarding customer interruption costs to provide guidance to users, allowing them to better estimate interruption costs and the value of reliability investments. This model was used by SDG&E for their filing.

Q27. YOU HAVE NOTED GRID MODERNIZATION BENEFITS DUE TO TRANSMISSION AND DISTRIBUTION IMPROVEMENTS IN RELIABILITY. DO ANY GRID MODERNIZATION FILINGS EXPLORE THE LOCAL AND SYSTEM BENEFITS OF DISTRIBUTED ENERGY RESOURCES?

A27. While some expenditures in grid modernization enable the utility to interconnect and safely operate the grid with increased amounts of varying, DER, no utility grid modernization filings that we reviewed defines an evaluation framework that accounts for the enabling function on the size and value of the DER market. However, two other documents which we reviewed do include some discussion of an evaluation framework for DERs: the Department of Energy (DoE) Industry Draft of its "Modern Distribution Grid, Decision Guide, Volume III, EPRI's Integrated Grid BCA, and the New York State Public Service Commission Staff "Value of DER" white paper.

Q28. PLEASE DESCRIBE THE LOCAL AND SYSTEM BENEFITS OF DISTRIBUTED ENERGY RESOURCES IN THE NY PSC STAFF WHITE PAPER.

A28. New York State's Public Service Commission (PSC) Staff "Value of DER" white paper describes an evaluation process that attempts to ascribe the full value of DER resources in offsetting expensive bulk system facilities and in reducing continued O&M expenditures on the bulk and local T&D systems. The PSC staff paper lists a series of potential benefits and proposed quantification methodologies to value the benefits which DERs can provide. The benefit categories are shown in Table 4 below. The majority of benefits attributed to DERs come from avoiding expensive investments in the bulk system or distribution system (using DERs to avoid generation, transmission, distribution capacity and avoid energy costs), while there are also some reliability benefits and external environmental and health benefits to DERs as well. Here, we briefly describe the PSC proposed methodology for avoided generation costs; the methodologies for valuing the other bulk system and distribution system benefits are similar.

Load-serving entities (LSEs) in New York are obligated to procure sufficient installed capacity to meet coincident summer peak, plus an additional reserve margin determined annually by the New York State Reliability Council. Additionally, LSEs within certain localities are obligated to procure a portion of their generation capacity from local resources within those localities. The New York ISO (NYISO) operates monthly and future spot auctions state-wide and in each of the localities. To evaluate the benefits of DERs in avoiding generation capacity, the PSC Staff proposes forecasting spot market demand and calculating a clearing capacity price using a spreadsheet model and assuming all available resources clear the market. This provides capacity prices and quantities at the transmission level; by procuring DERs instead of traditional grid-scale resources and re-calculating the capacity demand and spot prices, the avoided generation capacity benefit can be attributed to DERs both state-wide and in geographically constrained locations as well.

Some care must be taken to avoid double counting of benefits. Capacity clearing prices include a portion of transmission capacity infrastructure costs, so valuing the benefits which DERs provide for avoided generation capacity by counting for local capacity prices also includes a portion of benefits which DERs provide in avoiding transmission capacity. Thus, the PSC recommends ensuring that the portion of avoided transmission costs that are included in the capacity prices are not monetized in the separate avoided transmission capacity benefits category as well.

Details for the various other benefits of DERs can be found in the PSC staff white paper, but the broad methodology focuses on the cost of meeting various system requirements

using traditional grid resources, and translating this need into avoidable costs or benefits which investment in DERs can mitigate.

Table 4. New York Benefits of DER

	PSC Staff Whitepaper DER Benefits
Benefits	Direct and Indirect
Bulk System Impacts	
Generation Capacity	I
Energy	I
Transmission Capacity	I
Reduced Transmission Losses	I
Avoided Ancillary Services	I
T&D System Benefits	
Avoided Subtransmission Capacity	I
Avoided Distribution Capacity	I
Avoided O&M	I
Avoided Distribution Losses	I
Avoided Restoration Costs	I
Avoided Customer Outage Costs	I
External Benefits	
Avoided Emissions	
Avoided Water Impacts	
Avoided Land Impacts	
Non-Energy Benefits	

* Direct benefits include benefits directly attributable to grid modernization (AMI infrastructure, distribution automation, etc.), whereas indirect benefits accrue from technologies which are enabled by grid modernization expenditures.

Q29. PLEASE BRIEFLY DESCRIBE THE BENEFITS OF GRID MODERNIZATION DESCRBED IN THE DOE "MODERN DISTRIBUTION GRID DECISION GUIDE."

A29. The DoE "Modern Distribution Grid Decision Guide, Volume III" offers a framework for analyzing the cost-effectiveness of various grid modernization investments. Unlike the NY PSC Staff white paper, or the more traditional applications described earlier, the DoE cost-effectiveness framework does not explicitly list a series of benefits which grid modernization technologies offer. Rather, the decision guide states that the particular cost-effectiveness framework for each grid modernization investment must change depending on the expenditure's purpose.

For example, the guide suggests that when grid expenditures are replacing aging infrastructure or maintaining reliable grid operations, the cost-effectiveness methodology should be least-cost, best-fit or "other traditional methodology recognizing the opportunity to avoid replacing like-for-like and instead incorporate new technology."

Grid expenditures not required for safety or reliability, but proposed to enable DER integration or utilization should be evaluated in relation to the benefits of the associated DER using an "Integrated Power System & Societal Benefit-Cost." DoE points to the New York Reforming Energy Vision Benefit-Cost Framework, which is the PSC "Value of DER" white paper referred to above. The grid investments are the costs against the benefits of the DER to yield the net value. If the net value of the DER is positive, then subsequent funding requests for related grid investments should evaluated as least-cost, best-fit as long as the request does not exceed the cost in the original benefit-cost evaluation. If public policy supporting customer DER adoption and/or utilization for grid services has already been established then the enabling grid investments are required. In this case, the grid investments should be evaluated on a least-cost, best-fit basis.

Grid expenditures that will be paid for directly by customers (e.g. by customers participating in DER programs by a self-supporting margin neutral opt-in DER tariff, or as part of project specific incremental interconnection costs) are "opt-in" or self-supporting and do not require any regulatory benefit-cost justification.

Q30. HOW IS HAWAII DIFFERENT FROM OTHER JURISDICTIONS CONSIDERING GRID MODERNIZATION PLANS?

A30. Other jurisdictions such as California and New York are experiencing increasing rates of customer DER adoption, and are planning grid modernization activities around the future challenges and opportunities of changing customer participation. Hawaii, however, is closer than any other jurisdiction to experiencing the effects of DER penetrations on system operations and reliability. Near-term, the challenges include:

1. Reaching system level hosting capacity levels, where uncontrolled customer energy production exceeds the system's capability to absorb the energy they produce.

2. Reaching circuit hosting capacity levels, where expenditures in new infrastructure are necessary to accommodate more export DER.

While in the long-term DER can provide many benefits and opportunities to customers and to the grid, DER adoptions are driving the near-term need for grid modernization in Hawaii.

Q31. HOW WOULD YOU CHARACTERIZE HAWAIIAN ELECTRIC'S GRID MODERNIZATION EVALUATION APPROACH USED IN ITS 2016 GRID MODERNIZATION FILING?

A31. The Companies prior filing was generally consistent with the National Grid and SDG&E filings described above because of its focus on the traditional direct cost savings from reduced outages, variable operating and maintenance costs from distribution, reduced losses and labor savings from meter reading. Although the filing mentions other DER enabling benefits described by the NY PSC, it did not quantify them.

Q32. WERE THERE EXPLICIT DIRECTIONS FROM THE COMMISSION ORDER 34281 THAT DEFINE THE MINIMUM STANDARDS OR CHARACTERISTICS OF THE EVALUATION FRAMEWORK THAT SHOULD BE USED IN THIS FILING?

A32. Yes, the Order directs the utility to "ensure the cost-effectiveness of grid modernization investments" (p. 45) and ensure that its revised proposal also comply with the following guidance:

- Smart Grid Strategy and Roadmap needs to be **sufficiently detailed** and to allow parties and the commission to fully evaluate costs and benefits. **[pp 42, 66]**
- The overall goal is to develop modern grid investments pursuant to appropriate priority and sequence and at an ***optimal pace***. **[pp 7, 18, 51, 61]**
- Be among the leading jurisdictions in ***integration*** of cost effective DER into bulk power system high renewables planning **[pp 20, 36, 41, 42, 62]**
- Build on the **DOE guidelines** and borrow **benefits methodology from other leading jurisdictions [pp 62, 63]**

Q33. WOULD ANY OF THE EVALUATION PLANS YOU REVIEWED BE SUITABLE FOR RESPONDING FULLY TO THE FOUR REQUIREMENTS DESCRIBED IN THE COMMISSION ORDER?

A33. The order sets a very high compliance bar. While we find the Order well developed and completely understandable given the importance of making the DER implementation pathway a success in Hawaii, no other single jurisdiction or document provides a complete blueprint to satisfy the Commission order.

Q34. HOW CAN THE EVALUATION PLANS YOU REVIEWED BE LEVERAGED AND INCORPORATED INTO AN EVALUATION METHODOLOGY TO SATISFY THE COMMISSION ORDER?

A34. We recommend following the DOE guidelines document to unpack the various expenditures into their root causes and assessing them separately to provide the detail and transparency called for by the Commission Order. The categories of potential benefits will include all the direct benefit categories identified in the NY PSC whitepaper.

However, we also need a process that relies on optimization of net benefits to Hawaii's electricity consumers to address the commission concerns regarding optimal grid modernization deployment and timing of resources. Grid modernization can enable customer choice among DER resources, helping to achieve Hawai`i's renewable energy goals. The most effective method for evaluating DER enabling grid modernization investments is within the context of resource planning. Those categories of grid investment that are specifically to enable DER growth and utilization must be considered in the context of the benefits that those DER will provide. In turn, those DER net benefits should be considered in the context of an overall resource plan such as the PSIP.

Collectively, holistic resource planning with input from grid modernization plans can put Hawaii right on the cutting edge of optimal renewable resource evaluation including both large-scale resource integration, transmission investments, and DER benefits and related grid modernization costs. This is what EPRI calls Integrated Grid planning and is described in Section 4.1.1. of the grid modernization strategy.

The following Section 4, describes our proposed evaluation approach.

SECTION 4: COST BENEFIT METHODOLOGY

Q35. PLEASE BRIEFLY DESCRIBE THE BENEFIT AND COST FRAMEWORK YOU PROPOSE TO USE TO EVALUATE THE STANDARDS, SAFETY, AND POLICY COMPLIANCE PROJECTS AS WELL AS NET BENEFIT PROJECTS.

A35. We evaluate projects based on the 4 expenditure categories described in Section 1. The categories reflect the root cause of the expenditures, with the benefit cost treatment varying by category. The categories and benefit cost treatments are listed below.

Standards and Safety Compliance: expenditures needed to meet standards and safety requirements on the system. The need for these projects is not based on benefit cost analysis, but on standardized reliability and safety criteria. Selection of the projects to meet that need is based on *lowest reasonable cost* selection among potential options.

Policy Compliance: expenditures required to support and enable additional Commission policies. One example might be to support customer choice (e.g.: support customer-sited PV). As with the previous category, project selection from available options is based on lowest reasonable cost assessment.

Net Benefits: expenditures that can lower costs for all ratepayers. These investments are for initiatives that go beyond what is needed to comply with Standards, Safety, or Policy requirements, as well as projects identified in the integrated resource planning process (e.g. to promote or enable additional DER to provide system and local capacity and integration benefits). Net Benefits expenditures are evaluated using a TRC framework and an estimate of potential cost shifts.

Self-Supporting: expenditures that customers install based on their own economics and preferences and cause no embedded cost shift to other customers. Prevention of a cost shift may require that the customer also be served on a

> margin neutral rate based on the Companies' costs of service. With a margin neutral rate, fixed costs are collected through billing determinants like customer charges that do not vary with usage; and variable costs like fuel, operations and maintenance, and avoided capital are included in billing determinants like energy that do vary with usage.[18]

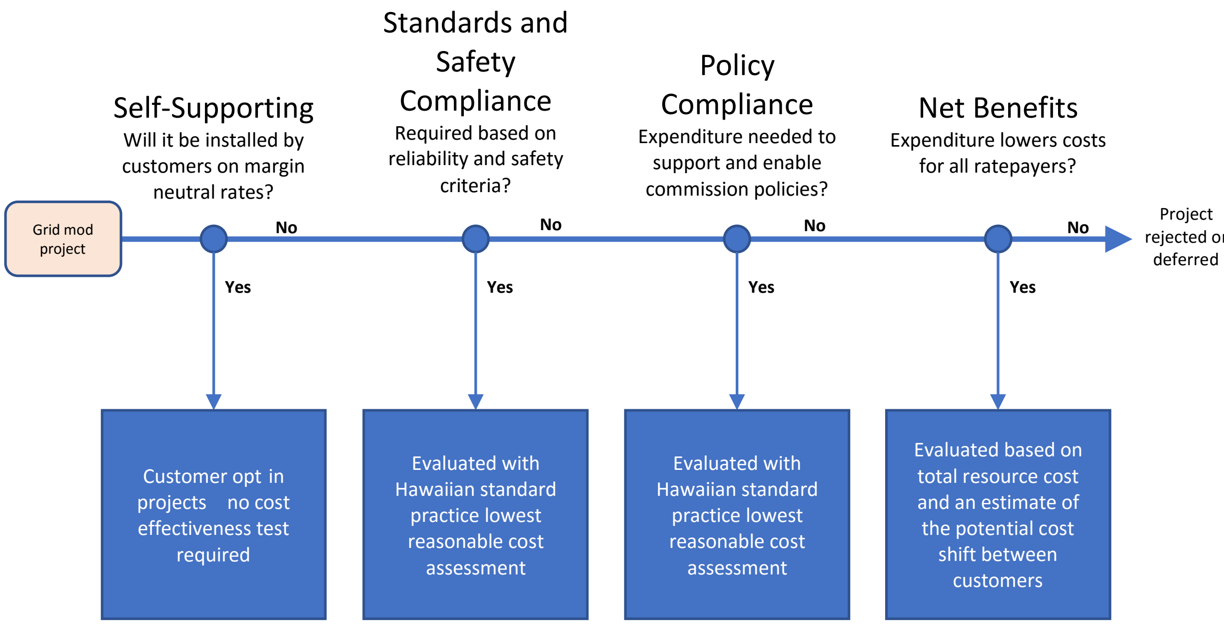
In evaluating the cost effectiveness of the expenditures in the Net Benefits category, we consider those initiatives to be incremental to the work in the first two categories. For example, if core communications and data management work is required for reliability and policy compliance, then the Net Benefits analysis would assume that work is already completed and not include those costs in its TRC analysis. However, if additional communications or data management costs would be incurred for the Net Benefits project, then those additional costs would be included in the TRC analysis.

Also, for Net Benefits projects that are required as part of an integrated solution, the costs and benefits of the entire solution, not just the grid-related subset, would be included in the Net Benefits analysis. For example, if a Net Benefits project is required to enable DER adoptions as part of a new integrated initiative, then the costs and benefits of the DER will be included in the evaluation. Note that in this example, the integrated solution would be determined as part of the utility resource planning process, which may precede the proceeding that would approve the actual grid-related portion of the integrated project. In such cases, the project would be part of the least cost resource plan, and the Companies would not "re-justify" the project in the grid-related proceeding, but would present the grid-related portion of the project under the Policy Compliance category.

The process of project grid modernization project evaluation is shown in the decision tree in Figure 1. Each step is evaluated as incremental to projects identified as part of the previous bucket.

[18] Please see proposed Consolidated Edison and Orange & Rockland SHR Demonstration Project for examples of self-supporting rate designs offered on an "opt-in" basis for DER customers.

Figure 1. Decision tree showing evaluation of a grid mod project



Q36. PLEASE DESCRIBE THE MODELING APPROACH YOU PROPOSE TO USE TO EVALUATE COSTS AND BENEFITS.

A36. For projects that only affect the local distribution grid, we apply a TRC test with the recognition that the benefit and cost impacts for most categories would be zero or not applicable. Because projects in the Net Benefits category would not be necessary to meet existing Standards, Safety, or Policy needs, an emphasis would be placed on quantifying and monetizing the incremental benefits of the expenditures (such as increased reliability and operational savings).

For expenditures that would impact the grid and system requirements, we use an integrated system transmission and distribution (T&D) modeling approach that determines the total cost of providing service to customers. We leverage the RESOLVE cases and model developed for the Companies December 2016 PSIP system modeling filing. The RESOLVE model is an optimal expansion planning model capable of developing least cost plans comprised of both bulk power and distributed resources. Other models with similar capabilities could be used also. To evaluate grid modernization investments, the RESOLVE model will be augmented with the following additions:

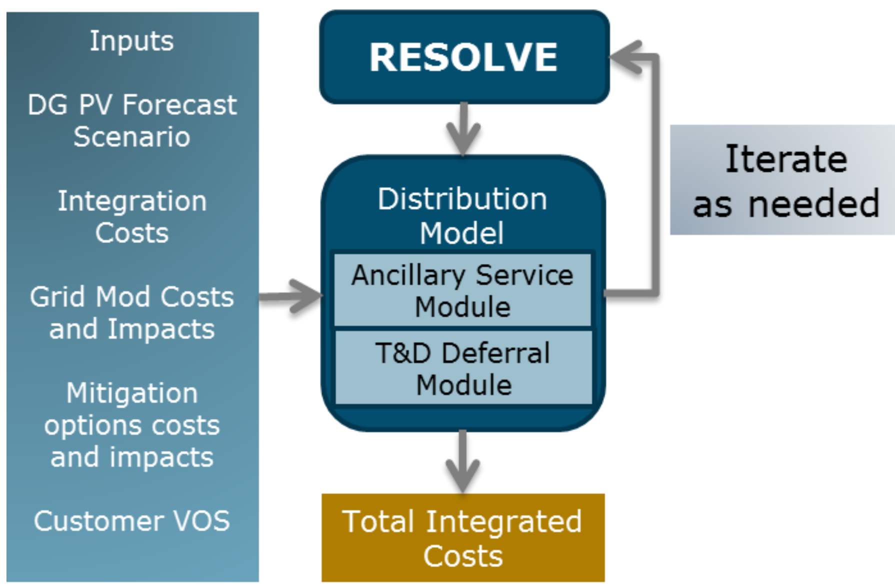
1. Expansion of the operations and maintenance category of costs to include operational costs such as revenue cycle services, as well as customer outage costs. Addition of ancillary services module to better estimate the system benefits that

can be provided by some DER. This adds the types of benefits identified in the NY PSC whitepaper.

2. Addition of T&D deferral module to estimate T&D plant savings that could be provided by DER in some locations. This also adds benefits identified in the NY PSC whitepaper. Candidate T&D investments that could be avoided by DER (or required because of DER) are inputs to the model and are identified through Hawaiian Electric engineering studies.

As shown in Figure 2 below, the two modules process the local costs and benefits input data to develop a new distribution model that works in tandem with the RESOLVE optimal expansion model. Both models working together, along with the expanded operational and customer outage costs, produce an estimate of a total least cost expansion plan that includes grid modification costs as well as DER system and local benefits.

Figure 2. Costs and benefits calculation for grid mod investments that change operations



Q37. CAN YOU PROVIDE AN EXAMPLE OF HOW THE INTEGRATED EVALUATION WOULD DETERMINE WHETHER A PROJECT SHOULD PROCEED?

A37. Assume we are evaluating grid modernization investments to enable incremental adoptions of DER that would be available as both a system and local grid resource. For costs, we include the cost of the DER and the related grid modernization costs required for the project (this excludes grid modernization work that is already included required

to comply with Standards, Safety, or Policy). For benefits we include the grid and local benefits provided by DER as well as any reliability or operational benefits of the grid modernization work.

If the combined net benefits are not positive, then the DER proposal should not be approved and the related grid modernization investment should not be implemented. This is very similar to the approach in FERC 1000 related to the assessment of transmission investments to enable policy related renewable objectives and any individual proposed resource projects. If the net benefit of the resource proposal is not positive the resource proposal is not approved and the transmission investment isn't made.

Q38. WHICH COST TEST PERSPECTIVE DO YOU USE FOR YOUR EVALUATION?

A38. We rely upon an expanded Total Resource Cost (TRC) test for determining project cost effectiveness for estimating the net benefits for proposed expenditures. The expanded TRC test includes customer outage costs and non-energy benefits that are not included in traditional TRC tests. We believe this is the most appropriate perspective for evaluating projects that will be funded by Hawaii ratepayers. Table 5 below shows the categories of benefits and costs used in the TRC test.

Table 5: TRC Test Benefit and Cost Categories (Included categories indicated by an 'X')

	Total Resource Cost (TRC)
Benefits	
Bulk System Impacts from RESOLVE Model	
Generation Capacity	X
Energy	X
Transmission Capacity	X
Reduced Transmission Losses	X
Avoided Ancillary Services	X
T&D System Benefits	
Avoided Subtransmission Capacity	X
Avoided Distribution Capacity	X
Reduced O&M	X
Avoided Distribution Losses	X
Avoided Restoration Costs	X
Other Operational Benefits	
Reduced revenue cycle service costs	X
Reduced restoration and staging costs	X
Customer Benefits	
Reduced Customer Outage Costs	X

Increased customer choice	?
External Benefits	
Avoided Emissions	X
Avoided Water Impacts	X
Avoided Land Impacts	X
Non-Energy Benefits	?
Incremental T&D Costs	X
Incremental Program and Admin Costs	X
Increased Ancillary Service Costs	X
Participant Costs	X
Lost Utility Revenue	
Non-Energy Costs	?

Q39. DO YOUR MODELS EVALUATE ALL BENEFITS OF DER AND RELATED GRID MODERNIZATION?

A39. No, our analysis focuses on the hard dollar expenditures and customer outage costs (which have been monetized through numerous value of service studies). We do include all of the direct grid benefits and indirect benefits described in the above table. However, because some of the customer facing and environmental benefits are difficult to quantify, such as the value of customer choice or monetized environmental impacts of new infrastructure, they are excluded from our analysis. For that reason, our analysis will be a conservative valuation of project cost effectiveness in many cases.

Q40. WHAT IS THE BASIS FOR YOUR ANCILLARY SERVICE EXPENDITURES?

A40. At present, ancillary services are not differentiated by time duration in Hawaii. Hourly upward and downward reserve requirements were used in the PSIP to represent the system needs in the future. Downward reserve requirement is equal to the single largest load contingency on each island, and upward reserve requirement is determined by the largest supply contingency and the quantity of renewables installed on the grid. Ancillary service expenditures are determined by the resources dispatched for upward and downward reserves. Grid modernization that can offer some of these two grid services and reduce grid scale resource reserve needs will receive the resulting system expenditure reduction as a benefit. The avoided expenditure is from either reduced resource investment or reduced fuel burn for ancillary services in the RESOLVE model.

Q41. WHAT IS THE BASIS FOR YOUR AVOIDED T&D CAPACITY BENEFIT?

A41. The benefit is based on the ability of the project to defer the need for T&D capacity expansion projects. Traditionally, this has been a function of reducing end use loads so that less power needs to flow down the grid to the customers. With high penetration levels of DER, however, the T&D benefits can include reducing the need to upgrade capacity to accommodate reverse power flow from the customer up through the grid. The T&D capacity benefit in our evaluation model captures the potential benefit of deferring both types of capacity additions based on utility expansion plans and expected DER adoptions.

Q42. HOW DO YOU ESTIMATE CUSTOMER OUTAGE COSTS?

A42. Outage costs will be estimated using the Interruption Cost Estimate Calculator (ICE). The tool was developed by Nexant and Lawrence Berkeley National Laboratory for utilities to estimate their interruption costs. Reductions in these costs from grid mod improvements in reliability will be attributed to grid mod projects as benefits.

Q43. HOW DOES YOUR ANALYSIS INTERACT WITH THE WORK THAT WAS DONE FOR THE PSIP UPDATE REPORT IN DECEMBER 2016?

A43. There was extensive Company, consultant, and stakeholder involvement associated with the PSIP work. We therefore use that work as the base case starting point for the integrated cost effectiveness analysis. When evaluating the costs and benefits of grid modernization projects, we estimate the change in total island electricity-related costs, with a focus on the interaction between DG PV and storage, the requirement for grid resources, and the impact of grid modernization investments on distribution upgrades to maintain system operability, safety, reliability, and power quality standards.

By taking a "total island" approach, our analysis reflects the interactions between grid investments and DER. Such interactions include:

- Reduction/increase in grid PV resources if DG PV resources increase/decrease.
- Reduction in grid storage requirements due to increase in distributed storage or flexible loads.
- Reduction in grid resources due to reduction in customer net demand from DER, voltage conservation, load shifting etc.

- Reductions in grid-level renewable resource curtailments if curtailments are implemented for local DG resources to address local over-generation constraints.

- Reductions in sub-transmission capacity expansion projects if distributed generation can mitigate the need for grid renewable resource additions in constrained generation pockets.

- Reductions in grid scale resources or curtailment if grid modernization investments can reduce grid scale ancillary service requirements.

Q44. DOES YOUR ANALYSIS CONSIDER UNCERTAINTY IN THE AMOUNT OF DER THAT IS EXPECTED TO BE ADOPTED?

A44. Yes. The forecasts of enabled DER adoption is uncertain primarily because the timing and levels of DER adoption are not within the Companies' control, and the potential rapid innovation and evolution of technology. We therefore analyze the benefits of grid modernization under a plausible range of DER forecast scenarios.

Q45. HOW DOES 'COST SHIFT' FACTOR INTO YOUR ANALYSIS?

A45. For self-supporting projects, margin neutral rates or incentive structures are required, so that there will be no expected cost shift effect. For the Net Benefits projects, an analysis of the cost shift impact will be included as an additional evaluation metric, if these customers are not served on margin neutral rates. While the cost shift is not part of the TRC analysis, it is an important factor in considering the distributional equality of a project. The cost shift is the net shift in utility cost collection from program participants to non-participants. For example, if a participant were to receive $1000 in bill reductions for installing DER, yet provide only $800 in cost reductions (both short run and long run) for the utility, then there would be a $200 cost shift to non-participants.

SECTION 5: EXAMPLE EVALUATION

Q46. PLEASE DESCRIBE AN EXAMPLE FINAL GRID MODERNIZATION PLAN FOR PURPOSES OF DEMONSTRATING THE BENEFIT COST METHODOLOGY.

A46. The example plan has the following components:

a. Aging equipment is replaced where required.

b. Companies require all **new** inverters for rooftop PV systems to be curtailable in response to a signal from the utility. New inverters are also capable of volt/var control. This is part of an opt-in “smart load” program on a margin neutral rate where customers are compensated for grid services offered, such as curtailment, voltage control, load shifting etc.

c. Investment in DERMS to provide visibility into DER operations and control over DER systems to implement “smart load” programs. It forms backbone controls and visualization technology required for all future DER additions.

d. Communications to incremental DER additions are implemented through wireless networking.

e. Companies install var compensators on final line transformers to provide better voltage control and ultimately reduce energy use through voltage reduction.

f. Companies install distribution connected storage devices at locations with high rooftop solar production.

g. Real time monitoring devices, reclosers, and communications between them, are added to improve system reliability and safety on vulnerable feeders that do not meet minimum reliability standards.

Q47. IN THE EXAMPLE, HOW WOULD THESE COMPONENTS BE DIVIDED AMONG THE INVESTMENT CATEGORIES?

A47. The components in the previous section would be divided into the following categories for purposes of demonstration:

1. **Standards and Safety Compliance:** Aging equipment is replaced to maintain reliable and safe operations of the system. Real time monitoring, reclosers, and communications are added to parts of the system to maintain safe operations. The SAIDI and SAIFI standards defined in Docket No. 2013-0141, dated May 31st, 2013, are used to define where investments are needed to maintain reliable service. Var compensators would be installed to manage voltages within standards, and their costs included in this category.

2. **Policy Compliance:** Investment in DERMS is justified by the HPUC ruling on use of aggregators in the DR proceeding (Docket No. 2015-0412, dated December 30th, 2015). DERMS will be necessary for real time monitoring and control of DER devices installed by customers.

3. **Net Benefits:** Storage devices avoid infrastructure investments that would have otherwise been required for high solar penetrations. Other benefits include dispatched grid services when not used for local deferral. Benefits are estimated and assessed against costs.

4. **Self Supporting:** New inverters will be installed by customers wishing to participate in the "smart load" opt-in programs. Their costs will be covered by customers that determine them to be a good investment based on the costs of their DER systems. Communications to incremental DER additions are also customer funded through agreements with wireless providers.

Q48. PLEASE EXPLAIN THE STEPS TAKEN FOR THE COST EFFECTIVENESS ANALYSIS OF THE PLAN.

A48. The cost effectiveness analysis is conducted in a series of sequential steps. These steps are as follows:

1. Standards and Safety Compliance projects are categorized. Those projects are selected based on a lowest reasonable cost assessment. Standards and Safety Compliance projects include work such as replacement of equipment, real time monitoring, and coordinated reclosers to maintain system reliability and safety. These types of work are core to normal utility practices and are evaluated industry-wide based on the idea of least-cost, best fit – the industry analogue to lowest reasonable cost in Hawaii.

2. The Policy Compliance projects are then identified and selected based on a lowest reasonable cost assessment. Like the Standard and Safety Compliance projects,

work in this category is not discretionary, and is necessary for the utility to meet State or Commission directives and goals.

3. Net Benefits projects are then evaluated assuming investments from Standards and Safety Compliance and Policy Compliance are in place. Both direct and indirect benefits for projects in the Net Benefits category are calculated, along with the costs associated with the indirect benefits (such as enabled DER). The costs associated with investments from Standards and Safety Compliance and Policy Compliance are not included in the Net Benefits cost effectiveness evaluation. The Net Benefits projects are evaluated using the TRC test. Any cost shift associated with the grid modernization work or its associated enabled investments are also calculated based on forecasts of rates and incentive mechanisms.

4. Self-Supporting projects are evaluated to assure that their compensation or incentive structure does not result in a cost shift to non-participants. No separate cost effectiveness test is required, as these projects are customer opt-in projects.

5. Evaluation of projects in step 3 could require an estimate of the future state of the system. A significant component affecting the benefits of grid modernization investments is the uptake of DER by customers (Self Supporting) and how that DER is operated. DER adoption is driven by DER-enabling grid mod investments and customer DER cost effectiveness under margin-neutral rates in the Self Supporting category. However, that cost effectiveness is dependent on system operations and avoided costs: by definition, DER in the Self Supporting category must be a part of a least cost TRC resource plan.

   For grid mod investments that affect operations and investments on the system, Net Benefits and Self Supporting projects are evaluated together using the RESOLVE model, where Self Supporting investments are determined by RESOLVE. The following steps are followed:

   a. Build cost supply curves of DER resources that are enabled by grid modernization investments. These supply curves will be differentiated by customer class, and adoptions will be limited by an adoption function to prevent unrealistic quantities of DER installations in relatively short time periods. Adoption functions will be simplified versions of those used in the December 2016 PSIP by the DR team.

   b. Create a dataset for modeling, incorporating the above supply curves, including data that are currently not represented in the December 2016 RESOLVE case, such as customer outage costs.

c. Characterize the operating constraints of DER. These may differ, depending on the grid mod investment being investigated. For example, without DERMS, DER may have more limited functionality than with it.

d. Supplement the December 2016 PSIP RESOLVE case with DER supply curves in place of the previously forecasted DER adoptions. Expected near-term investments in DER under existing tariffs may be forecasted and reflected in the model to represent a transition period between present rate designs and the assumed margin-neutral rate designs the Self Supporting category. Alternatively, long term DER investment scenarios that are not Self Supporting, but policy driven can be represented in RESOLVE to calculate their input on grid modernization investment benefits.

e. Run RESOLVE for each grid mod investment being investigated. Determine the cost savings over the base case, and the adoption of DER by Self Supporting customers.

f. Determine whether the investment passes the TRC benefit-cost test.

g. Run all grid mod investments in the Net Benefits category through the model to determine the portfolio TRC cost effectiveness of Net Benefit classified investments.

There are, however, many grid modernization investments that do not affect system operations and investments. These include reclosers, for example, that impact only system reliability and would not require treatment in RESOLVE. The var compensators and storage devices considered in this example both impact system operations and investments and therefore both require the RESOLVE approach to modeling benefits.

Q49. PLEASE PROVIDE AN EXAMPLE OF HOW A PROJECT IN THE NET BENEFITS CATEGORY IS EVALUATED.

A49. A simple example is reclosers to sectionalize lines and reduce the extent of outages. Assume that Hawaiian Electric has a $10 million project to add additional reclosers throughout its system. Of that, $3 million is required to maintain Hawaiian Electric reliability near its five year historical average, and $7 million would allow for increased deployment of reclosers to improve customer reliability beyond the historical average. In this case $3 million would be assigned into the Standards and Safety Compliance category and justified based on least-cost, best-fit. The remaining $7 million would be placed into the Net Benefits category for justification based on the TRC test.

The benefits would reflect any Standards and Safety Compliance category work already being in place. That includes the $3 million of new reclosers. The benefits are therefore the *incremental* improvement in reliability due only to the $7 million of reclosers, multiplied by the customer value of service over the lifetime of the reclosers. The costs are the revenue requirement increase associated with reclosers and their O&M lifecycle costs, plus a small increase in system costs to produce and deliver the energy to customers that would have otherwise been experiencing a sustained outage. The cost shift impact would be a very small improvement under existing rates because customers would be able to purchase slightly more electricity and therefore contribute more toward the repayment of utility fixed costs.

Q50. PLEASE PROVIDE AN EXAMPLE FOR A NET BENEFITS PROJECT EVALUATED AS PART OF THE INTEGRATED GRID PLANNING PROCESS.

A50. The Integrated Grid Planning Process is applicable to those projects that can impact both local and system grid needs. Storage located on the distribution system is an example of such a project. Storage devices are the most flexible of resources and provide the full spectrum of grid services with significant system gross benefits. Because storage devices could change system operations and investments, we would use the RESOLVE model for evaluation.

Replicating the potential benefits table from Table 5, categories that are not applicable to distributed storage have been grayed out in Table 6. Benefits are evaluated in the adapted RESOLVE model, as shown in Figure 2, where additional local benefits are calculated in the distribution model. Further detail on how the benefits and cost in the table could be quantified are provided after the table.

Table 6: Storage Example Benefits and Costs

	Total Resource Cost (TRC)
Benefits	
Bulk System Impacts from RESOLVE Model	
Generation Capacity	X
Energy	X
Transmission Capacity	X
Reduced Transmission Losses	X
Avoided Ancillary Services	X
T&D System Benefits	
Avoided Subtransmission Capacity	X

Avoided Distribution Capacity	X
Reduced O&M	X
Avoided Distribution Losses	X
Avoided Restoration Costs	X
Other Operational Benefits	
Reduced revenue cycle service costs	X
Reduced restoration and staging costs	X
Customer Benefits	
Reduced Customer Outage Costs	X
Increased customer choice	?
External Benefits	
Avoided Emissions	X
Avoided Water Impacts	X
Avoided Land Impacts	X
Non-Energy Benefits	?
Costs	
Incremental T&D Costs	X
Incremental Program and Admin Costs	X
Increased Ancillary Service Costs	X
Participant Costs	X
Lost Utility Revenue	
Non-Energy Costs	?

Benefits

- **Generation Capacity and Energy:** System benefit calculations depend upon the other resources present on the system in the future, so the selection of a base case is important. The base case should include any relevant projects identified in the Standards and Safety Compliance category and the Policy Compliance category. Storage is then added to the plan, and the capacity and energy benefits are estimated from the reduction to total system costs in the case with storage as compared to the base case.

- **Transmission and Subtransmission Capacity:** Distributed storage in some cases could allow for deferral or avoidance of subtransmission projects on Oahu by reducing the need to export power from grid-level renewable resource zones. The benefit is the present value revenue requirement savings to customers from the deferral or avoidance. Like many benefits, this will depend on the portfolio of other grid modernization projects as well as the adoption level and controllability of distributed PV.

- **Transmission Losses:** Changes in transmission losses are captured in the difference in change case and base case PSIP plans, as discussed for generation capacity and energy.

- **Ancillary Service Costs**: Ancillary service benefits are the product of the value of ancillary services and the amount of services that the distributed storage could provide.

At the portfolio, the total system need for ancillary services caps the total ancillary service value from all grid modernization projects.

- **Distribution Capacity:** Storage can provide distribution capacity benefits in two ways. Storage can provide traditional deferral value by reducing local area net peak demand and reducing the need for additional distribution capacity to deliver power to customers. In that case, the benefit is the present value revenue requirement reduction from deferring the distribution capacity project. Storage can also provide deferral or avoidance value by reducing the amount of reverse flow on the distribution system, in which case the benefit is the deferral or avoidance of the distribution equipment needed to support distributed generation.

  For these calculations, the value provided by storage will vary with its location. Current Company forecasts of new capacity needed to serve customer load (as opposed to serving customer DG) are low, so storage would ideally be located to reduce DG-driven investment needs. The storage could be modeled as reducing the amount of uncontrolled DG PV in the highest value areas, based on the distribution additions identified in studies such as Hawaiian Electric prepared for the PSIP Appendix N.

- **Reduced O&M.** Storage projects reduce the O&M associated with any deferred or avoided T&D projects above. The O&M savings is calculated as a percent of the capital cost reduction. Storage also reduces the wear and tear on distribution equipment such as tap changers. These benefits are fully attributed to the storage in the individual analysis, and capped under the portfolio analysis.

- **Avoided Distribution Losses.** Storage can reduce distribution losses by discharging at times of net peak load and thereby reducing the loadings on the distribution system

- **Other Operational Benefits.** Storage does not reduce revenue cycle service costs, and is not expected impact restoration costs.

- **Reduced Customer Outage Costs.** Depending on how the storage is configured, and its size relative to customer loads, there could be customer reliability benefits from the storage. Retaining storage capacity for reliability purposes, however, would reduce its availability and benefits for local grid or system applications.

- **External Benefits.** Emissions benefits would be calculated as the difference in emissions between the PSIP base case and the change case with the storage. At the current time, we do not expect to monetize emission benefits.

Storage Costs

- **Incremental T&D Costs.** The storage program would defer or avoid the need for T&D investments. This impact would appear as a benefit (above), and the cost category result would be zero. This contrasts with a program like customer-sited PV that could increase T&D costs for interconnection, protection, and reverse flow capacity needs.

- **Incremental Program and Admin Costs.** Maintenance, administration, and operation of the storage program would incur costs that should be included in the evaluation of the program.

- **Participant Costs.** If the program costs are partly borne by customers, those costs should be included in the TRC test.

- **Lost Utility Revenue. Lost utility revenue is not a component of the TRC test,** but would be included in the determination of any cost shift associated with the program.

- **Non-Energy Costs.** We do not include any non-energy costs at this time.

The net benefits and benefit cost ratios are calculated, with cost effectiveness being defined as a benefit to cost ratio of one or more. In some cases, however, the Companies may propose projects that do not pass the TRC test. Those projects would need to be separately justified.

In addition to the TRC test, the storage project would be evaluated for its cost shift impacts. For the cost shift calculation, revenue reductions for the utility (i.e.: participant bill savings and incentive payments from the utility) would be subtracted from the net benefits for the utility. The net benefits for the utility are the same as the TRC benefits excluding any customer reliability or choice benefits and any external benefits.

Q51. HOW ARE SELF-SUPPORTING PROJECTS EVALUATED?

A51. No benefit cost treatment is applied to Self Supporting projects in the grid modernization plan because customers will make these investments themselves if it is profitable for them to do so. Moreover, we assume incentives for customers that are margin neutral so that non-participants should be indifferent to program uptake.

Our example Self Supporting investments includes inverters and directly assignable communications expenses caused by the participants. The cost of the inverter and communications for each system is therefore added into the DER cost supply curve built for RESOLVE, as described in A.37.

Appendix D: System Operations and Considerations in a High DER Environment

SYSTEM OPERATIONS OVERVIEW

The Companies' serve five islands through independent electric grids originally constructed to provide the bulk power export from central station power plants to customers located throughout each island. The transmission, sub-transmission, and distribution systems were designed to be cost effective and efficient for the delivery of the bulk power to the different communities. Over time, the transmission, sub-transmission and distribution voltages and designs evolved to enhance reliability and minimize system losses.

The fundamental job of the electric grid is to ensure that power is available when customers want it. Because customers' demand can vary on a minute-by-minute and hour-by-hour basis, the electric grid was designed to manage fluctuations in demand by adjusting generation in real-time to provide customers with safe and reliable power twenty-four hours a day, seven days a week.

To provide a highly reliable system for our customers across the island systems, modern grid technologies have continuously been incorporated into the system, utilizing the solutions available at the time. The distribution system itself has evolved as communities were developed out from the city centers to all parts of an island. On more complex systems, alternative paths from which customers could be served are provided for added reliability. Slowly over time, more automation was added to the system to limit the extent and duration of outages our customers experienced. For example, distribution substations incorporate an automatic transfer system so that if one sub-transmission line trips out of service, the unit transformers will be automatically transferred to the back-up line.

Other technologies were utilized to help field personnel identify outage causes so that power could be restored more quickly when there were outages. Fault current indicators (FCIs) were installed on the sub-transmission lines and distribution circuits to help field personnel identify the source of the outage. Using the FCIs, field personnel are able to more quickly locate the problem area that caused the outage, isolate the problem area, and then begin the restoration of power to the affected customers.

Other technologies such as line reclosers or sectionalizers are used to isolate the problem location and minimize impact to other customers. Both line reclosers and sectionalizers are used for sectionalizing circuits to minimize the number of customers affected by a fault. Reclosers are able to interrupt fault current, have built in protection and are able to isolate faulted sections of line without having the main breaker trip. Sectionalizers are unable to interrupt fault current and require the main breaker to trip before they open. Subsequently, the substation main breaker can then reclose and restore customers not in the affected area. Reclosers provide additional flexibility in that they have built in protection that can be set more sensitive than the main breaker and can be used in auto restore type schemes like on the North Shore of O`ahu. In addition to reclosers and sectionalizers, automatic transfer switching vaults were deployed on the distribution system so that localized outages could be detected, isolated, and then power automatically restored to could be provided to the customers through an alternate path. These automatic transfer switching vaults in conjunction with the FCIs also helped crews narrow down their search to determine where the outage incident originated.

Monitoring and control of the electric grids improved with the implementation of energy management systems (EMSs)[118]. They were installed primarily to economically dispatch generation resources, and enable the system operators to remotely monitor and control the transmission and sub-transmission system. Operators could then monitor, assess and react to system events that had the potential to disrupt service to our customers. The control capabilities of the EMS are also utilized to perform switching operations on the transmission and sub-transmission systems that greatly assist the field resources and help improve the safety and efficiency of operation. Eventually the EMS capabilities were extended out to select distribution substations starting with those that could be used for the system restoration should the island suffer a blackout. This automation provided the system operators the ability to coordinate the addition of customer loads onto the system as generation comes came back online.

Absent a full deployment of control and monitoring systems to all distribution substations, an outage management system (OMS) was added at Hawaiian Electric to assist with identifying and tracking outages to our customers. The OMS depends on customers making calls to Hawaiian Electric to report an outage, but the software leverages those customer calls to and predict where the outage may have been initiated. For example, if all the customer calls are linked to a particular service transformer, the system operators could then send a crew to respond to the suspected transformer outage to first, verify that it did cause the outage, then to replace the transformer so that power can could be restored to the customers.

As the appropriate communication infrastructure is developed, more devices that can be monitored and controlled by the system operator will be installed on the distribution system. This will become a necessity as more and more distributed energy resources are added. The

[118] Hawaiian Electric and Hawaiian Electric Light Company have full EMS installations, while the implementation at MECO provides automatic generation control (AGC) only.

monitoring and control of the distribution system will allow more advanced software to be utilized to assist the system operators with managing the issues that might occur on the distribution system. Monitoring and protecting the system will be more complex because of the volume of data that will need to be collected to safely operate the distribution system. Therefore, advanced software systems will need to be utilized to identify and display warnings when conditions requiring intervention by the system operator occurs.

The volume of distributed, and customer owned DG-PV in Hawai`i, unprecedented in the U.S. electric utility industry, is creating new challenges for the Companies' grid operators. In order to ensure system security, central station resources must be scheduled to react to the intermittency and variability of customer-sited generation or other resources added to the system. This was extensively discussed in the Companies' PSIP filings in December 2016. On some circuits, DG-PV is so densely located and oversized relative to local demand that power is flowing back into the subtransmission system on about 50 percent of the Companies circuits.

BULK SYSTEM/TRANSMISSION CONSIDERATIONS

The Companies do not perceive these considerations as barriers. Rather they can be addressed through the integrated grid planning process and modern grid solutions.

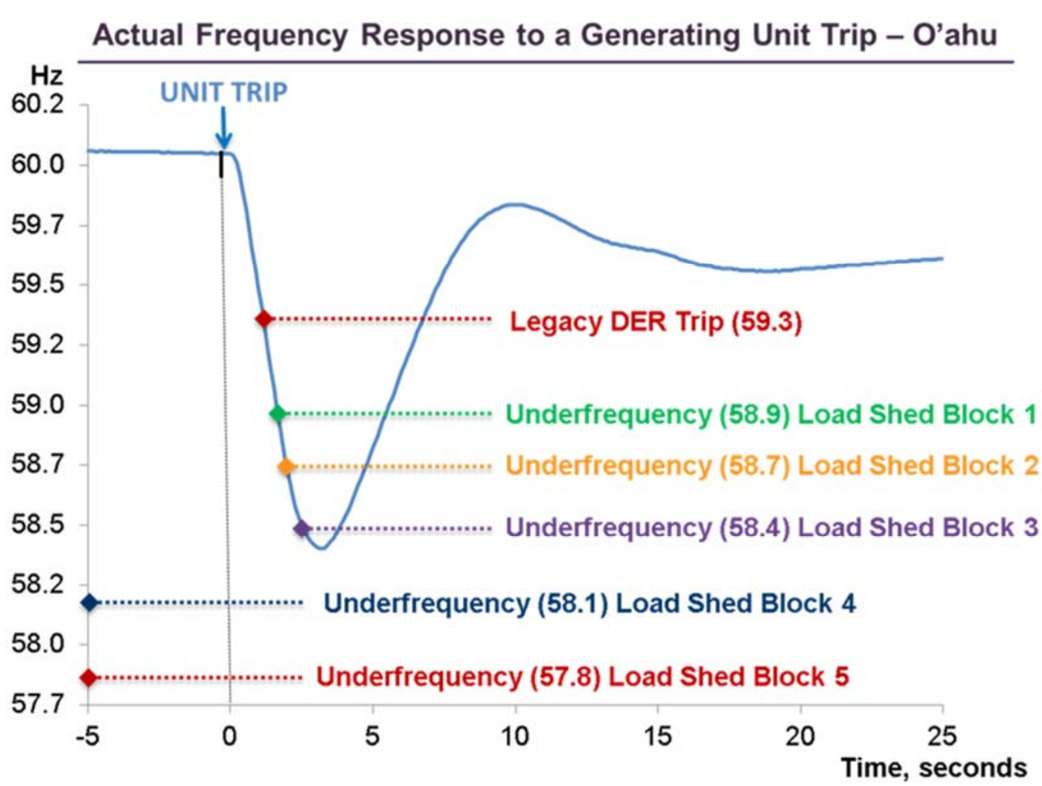
The bulk system/transmission consists of high voltage transmission lines for transportation of electricity over long distances, and generators interconnected to a network of transmission lines (with multiple paths) for high reliability of generation. Utility generation portfolios were historically constructed to best accommodate the normal and cyclical fluctuations in aggregate customer load, with daily and seasonal peaks and minimums. The transmission network is for the transportation of bulk energy to points at which lower voltage distribution circuits will deliver it to customer loads, and is the backbone of the electrical system that efficiently transports bulk energy from central station power plants to the load centers (i.e. distribution substations) with a specified level of reliability.

A synchronous generator is a large rotating electro-magnet that converts mechanical energy from the turbine into electrical energy. Besides real power, synchronous generators provide reactive power, rotational inertia, and short-circuit current necessary for reliable operation of the grid. Reactive power is required to support voltages on the transmission system; rotational inertia makes the system less susceptible to frequency disruptions caused by the loss of generation or electrical faults; and short circuit current is required for protective relays to detect electrical faults. A transmission system with more synchronous generally has better ability to; 1) adjust to changes in customer load demand; 2) support transmission voltages; 3) withstand the loss of generation or electrical faults; and 4) provide fault current. DG-PV begins to influence bulk system/transmission system reliability first through the reduction of the

aggregate load and eventually the displacement of synchronous generation. The result is lower ramping and regulating ability, lower ability to support voltage, less system inertia and less short-circuit current, all of which compromise the reliability and safety of the transmission network. Finally, reduction of the daytime load compromises the under frequency load shed scheme, which is designed to disconnect load in a controlled fashion to prevent much larger events, such as an island-wide blackout.

Today, conventional thermal generation is turned down or cycled off to "make room" for additional renewables, which reduces the amount of inertia on the system. Reduced inertia allows the system frequency to change more quickly, especially following a sudden major disturbance like the sudden shutdown of a generating unit. During these underfrequency events, which can occur multiple times a year, the load shed scheme activates to rebalance the load and generation. It is also notable that multiple underfrequency load shed blocks are activated to arrest the steep frequency decay. Because rooftop PV masks or offsets the load the utility serves on these load shed blocks, to prevent a collapse of the power system more load blocks are disconnected than previously experienced or designed for. The underfrequency condition further worsens when PV inverters trip offline at 59.3 Hz, the previous IEEE 1547 trip point for distributed generation. Figure D1 overlays the load shed scheme on an actual generator tripping event from April 2013.

Figure D 1 Frequency response of the Hawaiian Electric power system during the loss of the grid's largest



The lack of visibility of DG-PV are seen by the system operators as a change in "net load" viewed from and served by the bulk transmission system. This can change the traditional roles for various elements of the generation fleet, and with enough renewable generation, require changes to conventional practice. For example, high wind production overnight in the spring time (when nighttime load is low) can make it difficult to keep a large fossil fuel plant online. Such plants were traditionally thought of as a "baseload" resource and were designed for maximum efficiency at high output levels and for continuous 24/7 operation. Turning them down, or worse, cycling their output off and on, not only has negative efficiency and associated emissions impacts but may also result in higher maintenance costs.

DG-PV can also make managing the conventional generation portfolio more difficult. The output of many PV systems across a region can be highly correlated due to common sky conditions. The correlation will also persist as the sun rises and sets each day. At high levels of PV, what was once a well-known seasonal profile of daily customer load is transformed into a net load characteristic with multiple peaks – early morning and early evening – with bulk generation ramping down as the sun rises in the morning and ramping up as the sun sets and ramping down as the sun rises in the morning.

The shifting from the traditional paradigm of central synchronous generation to one where significant amounts of variable distributed generation is relied upon to meet customer electricity demand is challenging the ability to maintain system balance. As a result, system level generation requirements are changing across the islands as the result of more distributed generation. The figures below show increasing system-level challenges across each of the islands from 2013 to 2017. At a high level, these figures depict the following:

- Daytime minimum load served by the Companies is decreasing to the point that it is lower than the overnight minimum load;
- Variable output from renewable generation throughout the day results in significant ramping requirements from bulk system resources; and
- While the amount of solar connected to the system exponentially grew, the peak demand remains relatively unchanged.

Figure D 2 Hawaiian Electric System Load Fourth Week of January 2013–2017

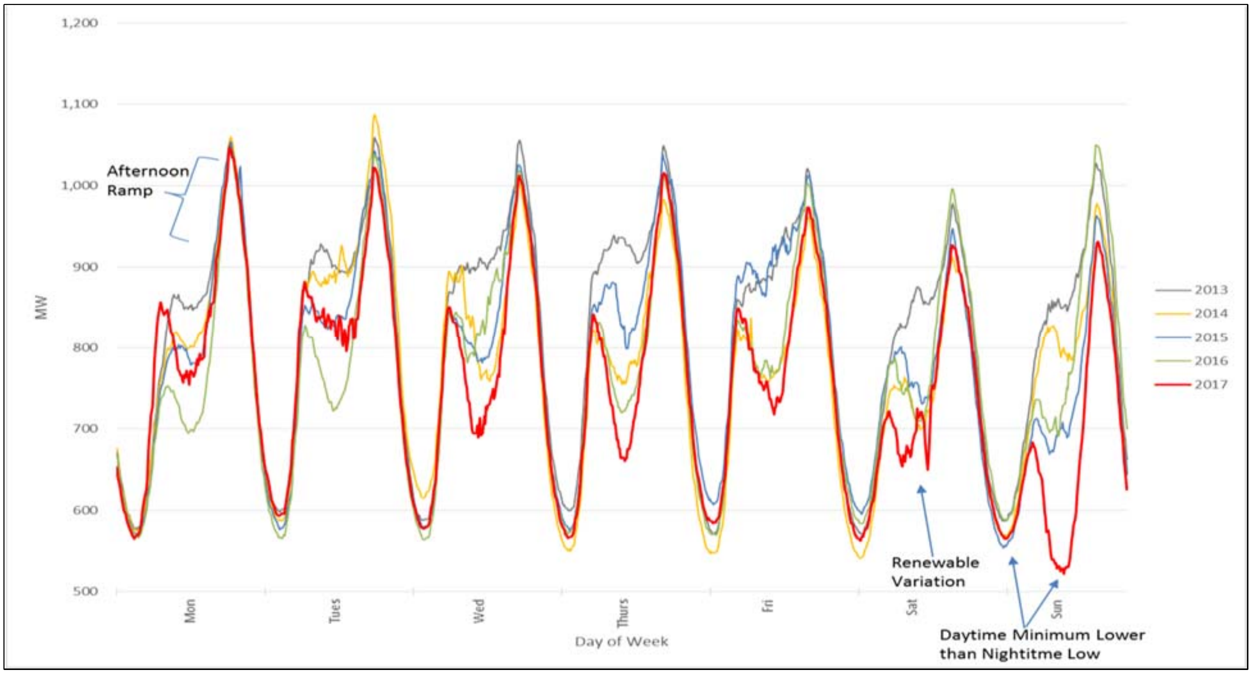


Figure D 3 Hawai`i Electric Light System Load Second Week of March

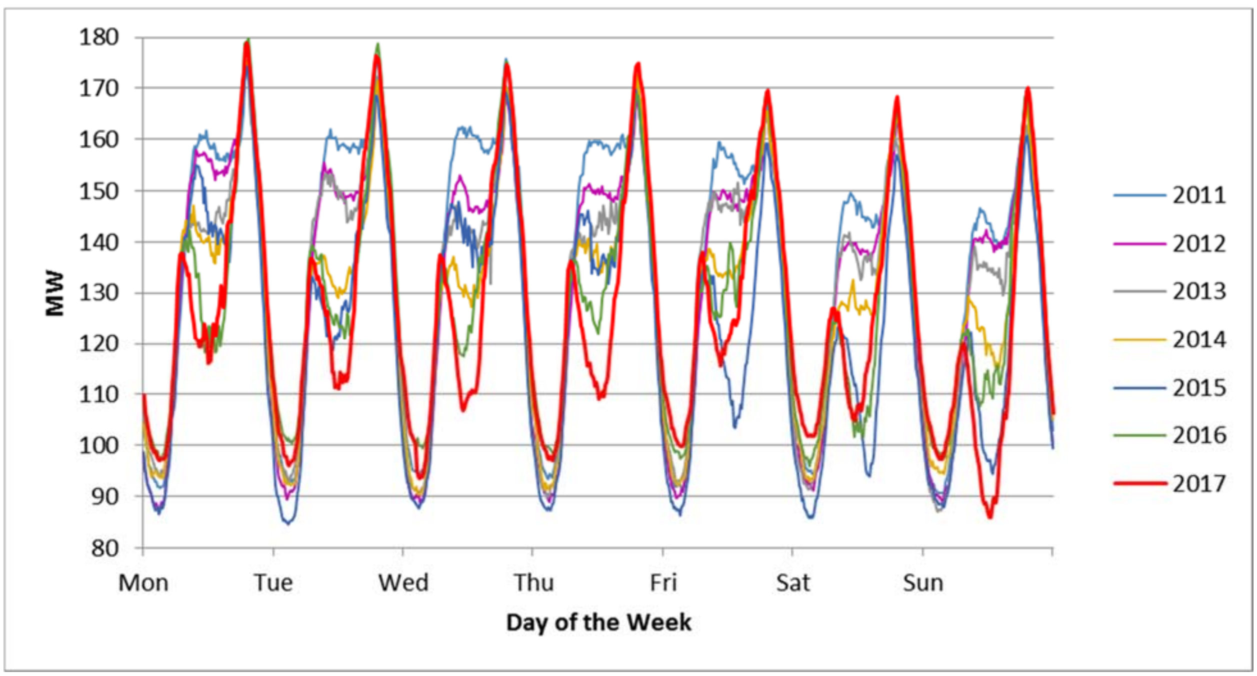


Figure D 4 Maui Electric System Load Third Week of March

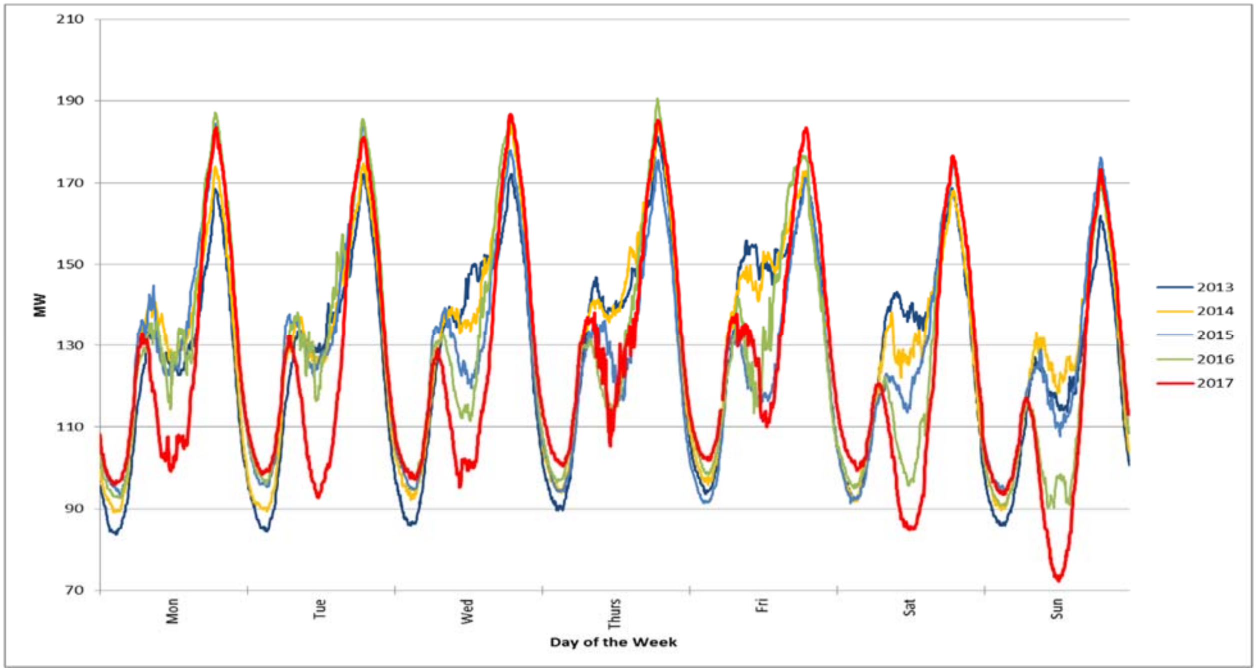
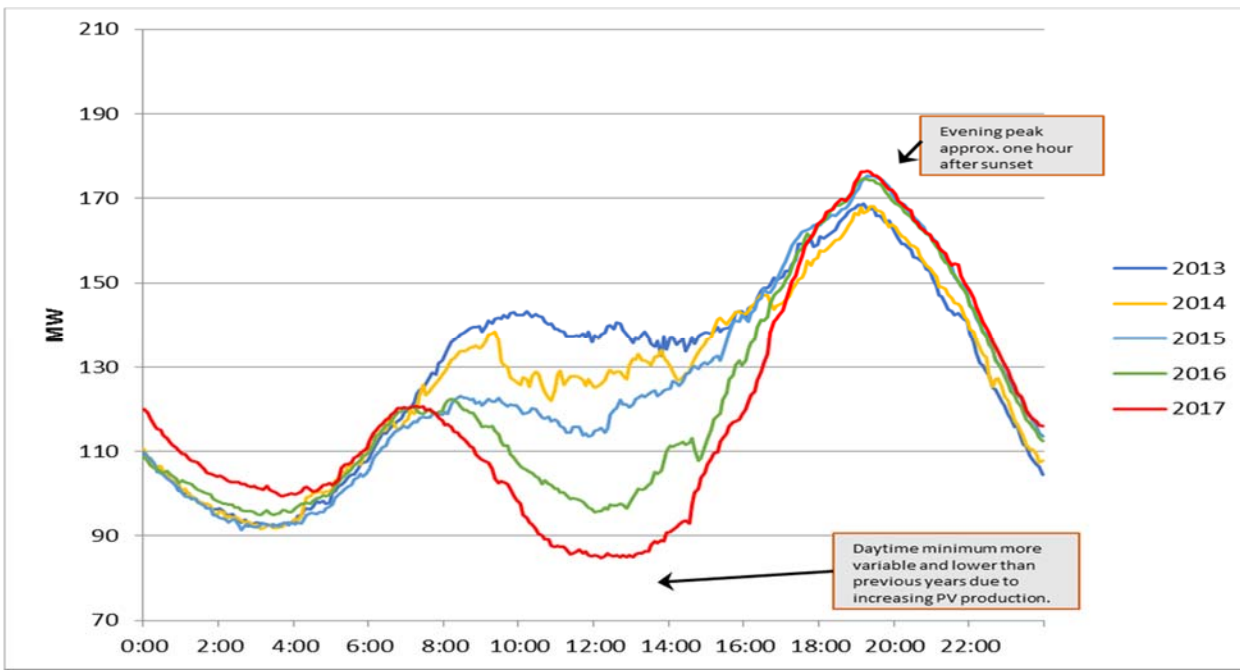


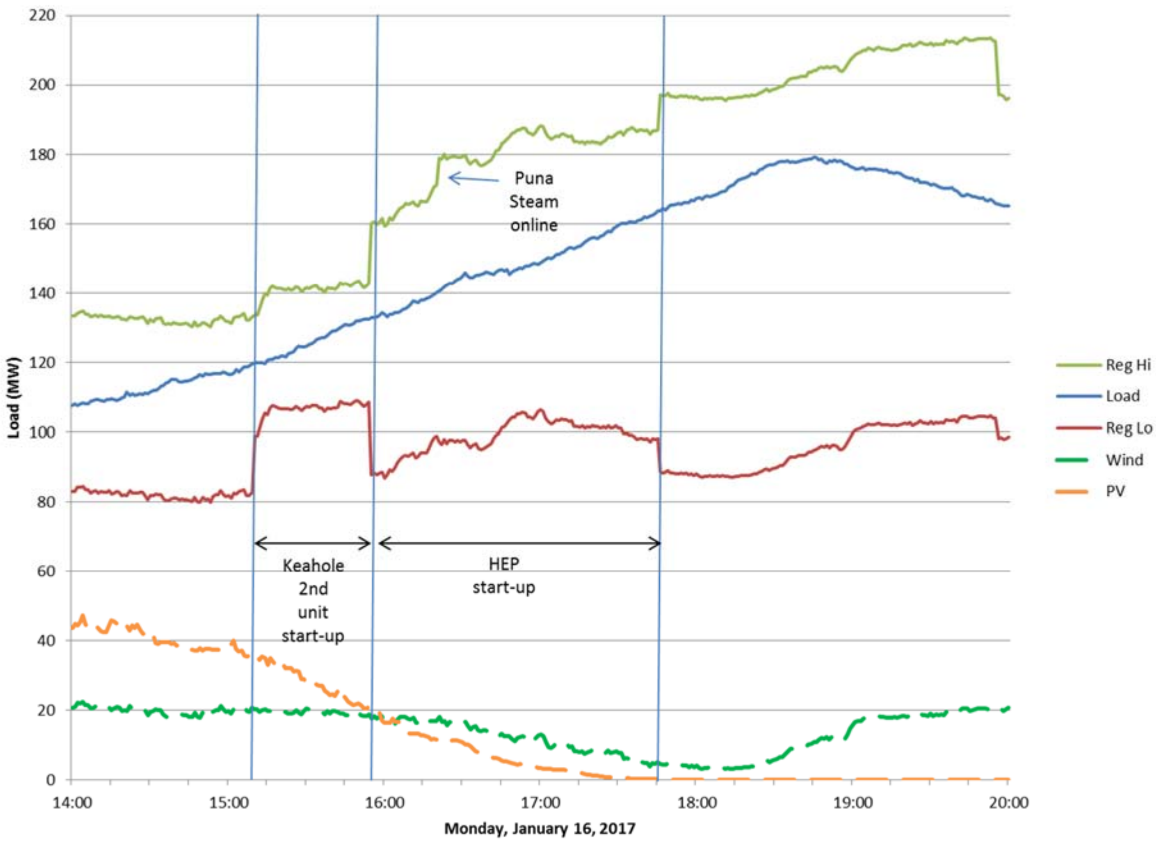
Figure D 5 Maui Electric System Load Saturday of the Third Week of March



The low daytime loads have significant impact on the ability to maintain grid frequency and stability. In some instances, the generation resources that have historically provided regulation services to balance the second-to-second variation in demand would create an oversupply (excess energy) situation. So much so that running those generators, even at their minimum output power would cause frequency instability. As a consequence, the bulk power system

loses access those regulation capabilities. This has tremendous effect on the ability of grid operations to manage the second-to-second variation in load. Figure D 6 is an example of the tight band that occurs between 15:00 and 16:00 as generation units come online to meet the rapid ramp in load as solar generation goes offline. It is anticipated that in the future these regulation capabilities can be met by an architecture consisting of new grid side regulating resources such as regulating energy storage, advanced inverter frequency-watt functionality, and demand response.

Figure D 6 Generation Resource Start-Up at HELCO to Meet Evening Demand Ramp with PV Going Offline



These system level generation and regulation challenges are growing increasingly complicated as more renewable generation is incorporated into the grid. These are the challenges that we already have insight into and there are likely more fluctuations in power quality occurring at more granular levels. As we move towards the future, all resources[119] need to contribute to grid stability and continue to provide the frequency regulation services that conventional generation had built-in. Future resources should be designed to allow leveraging of whatever

[119] "The electric system should evolve such that all generation resources, whether utility, IPP or customer-owned, will contribute to maintaining system stability. Therefore, to maximize the integration of variable renewable energy resources, the Commission expects the HECO Companies to require all generators to address and support system stability consistent with their resource characteristics and state-of-art technical capability" Commission's Inclinations on the Future of Hawaii's Electric Utilities, filed as Exhibit A to Decision and Order No. 32052, in Docket No. 2012-0036 at 7.

flexibility might be available. DER can integrate these capabilities into their management systems, but pilot projects completed across the United States have shown that the practicality of getting the resources to perform as expected or instructed is another challenge as the technology is new and not necessarily connected to system or customer needs.[120]

The upshot of these trends is important for the economics associated with current grid operation, as the challenges that were outlined above result in the following increasing needs:

- **Dispatchable generating resources are being displaced, along with the ancillary services provided by these resources.** – As the daytime minimum has decreased, dispatchable generating resources are increasingly being taken offline to accommodate production from DERs. An acceptable level of rotational inertia, reactive power support, and short circuit current must be maintained to ensure system stability.
- **The need for dynamic resources is increasing** – As the grid becomes more dynamic, the need for resources which can regulate grid frequency, provide voltage support, provide inertia, and provide fault current is increasing, as indicated in the variability during the midday in Figures D1-6.

With the existing grids, the economic impact of the above-mentioned effects is generally negative. The operating efficiency of existing generating units on the system are compromised because they are increasingly being operated at lower outputs, at times at minimum output, and cycling (start-up and shut-down) is becoming more frequent. On highly variable days additional generation capacity must be kept online (as ancillary service spinning reserves) in order to ramp up and ramp down output and balance supply and demand as variable and intermittent renewable generation resources fluctuate. During periods of high variable generation, grid scale renewable generation is curtailed after dispatchable generation is turned down to levels to maintain sufficient upward-reserve capacity (at times, minimum output), since none of the DG-PV installed to date are controllable. The Executive Summary of the PSIP describes the Companies near-term plans to integrating more renewables:

> "We plan to maximize integrating DER and DR resources, and begin efforts to procure grid-scale resources. We recently issued a request for information (RFI) to landowners to help inventory potential parcels for renewable energy development. With Commission approval, we would also issue request for proposals (RFPs) for renewable grid scale solar PV and grid scale wind installations for all five islands. These RFPs directly flow from the resource acquisitions outlined in our near term action plans and represent critical steps toward achieving the 100 percent RPS goal.
>
> We plan to initiate additional studies and projects to modernize our grid to allow full and cost-effective integration of distributed and grid-scale resources. Included in this

[120] Summary of First Solar's inverter-based regulation pilot: https://www.greentechmedia.com/articles/read/PV-Plants-Can-Rival-Frequency-Response-Services-From-Natural-Gas-Peakers

work are the necessary system security upgrades that ensure our transition to 100% renewable energy continues providing our customers with safe and reliable service."[121]

The December 2016 PSIP details the evolution of the Hawaiian Electric Companies grids from the near term onto the 2045 100% renewable objective. The December 2016 PSIP incorporates the Companies' High DER forecast which equates to all single-family residential homes and 20 percent to 25 percent of commercial customers (due to limited roof-top space) producing the same amount of PV energy as they consume. This DER forecast totals to the amounts of DG-PV and Customer Self-Supply storage in 2045 as shown in Table D1.[122] This forecast is significant in that the DG-PV forecast exceeds the current system peak load.

Table D 1 Solar Photovoltaic and Storage

Island	DG PV (MW)	CSS Storage (MW hr.)	2016 System Peak Load (MW)
O`ahu	2,101	733	1,192
Maui	435	172	201
Moloka'i	7.1	3.7	5,650
Lāna'i	7.8	5.0	5,700
Hawai`i	456	232	189

In the December 2016 PSIP, the Companies indicated it was working with Google to determine the technical potential of DG-PV. Since the submitting the December 2016 PSIP, Google has completed their technical potential of DG-PV for the islands of O`ahu, Maui, and Hawai`i[123]. The technical potential and comparison to the Companies High DER forecast are provided in the table below:

Table D 2 High DER Forecast and Technical Potential

Island	High DER Forecast (MW)	Google Technical Potential (MW)	Ratio, High DER Forecast: :Google Potential
O`ahu	2,101	3,200	0.66
Maui	435	514	0.85

[121] December 2016 PSIP, p. ES-11

[122] December 2016 PSIP, Appendix J, p. J-60-69: https://www.hawaiianelectric.com/about-us/our-vision

[123] Google Project Sunroof: https://www.google.com/get/sunroof/data-explorer/

Island	High DER Forecast (MW)	Google Technical Potential (MW)	Ratio, High DER Forecast: :Google Potential
Molokai	7.1	N/A	N/A
Lāna'i	7.8	N/A	N.A
Hawai`i	456	281[124]	1.62

The above comparison indicates that the High DER Forecast approaches the technical potentials estimated by Google, which suggests that the High DER forecasts are aggressive targets. The challenge is to realize these targets in ways that are consistent with the Companies' and Commission's objective to lowering and stabilizing electric bills. Grid modernization will be the key for realizing the full potential and benefits from the growing fleet of DER.

Curtailment of renewables or limitation of DG-PV growth on distribution circuits is the current solution for maintaining system reliability (i.e. operational reliability in NERC terminology - regulation for frequency control, contingency reserves, and flexibility reserves from conventional synchronous sources). It is important to note that grid modernization will enable continued growth of DER and the PSIP identifies new grid scale resources that are needed to optimize system operations and ensure grid reliability.

DISTRIBUTION CONSIDERATIONS

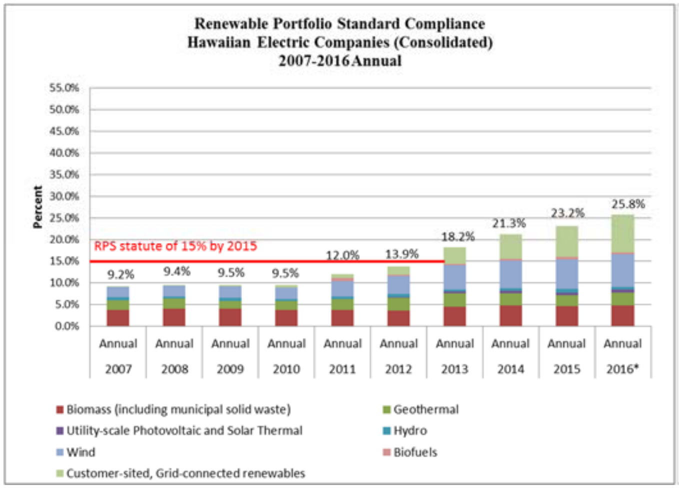
Hawaiian Electric, Maui Electric, and Hawai`i Electric Light Company are national leaders in the adoption of DG-PV with nearly 80,000 systems already approved for installation. Approximately one-third of all single-family homes on O`ahu have been approved to install a rooftop solar energy system. [125]

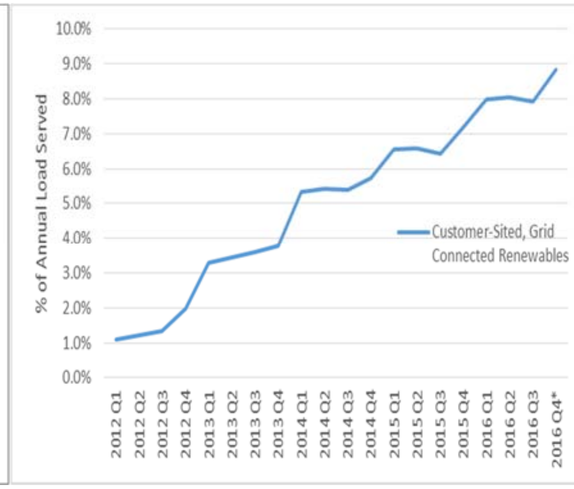
In recent years, the Companies have met and exceeded the state's RPS goals and Figure D 7 shows the historical RPS-qualifying resource mix. The growth in renewable generation has been buoyed by a rapid growth in customer-sited renewable energy generation. Hawai`i continues to integrate distributed generation at a rapid rate.

[124] Google's mapping and data coverage for Hawaii was only 40%, thereby impacting the estimate for Hawaii.

[125] New wave of rooftop solar energy systems offer options for Hawaiian Electric customers, September 8, 2016: https://www.hawaiianelectric.com/new-wave-of-rooftop-solar-energy-systems-offer-options-for-hawaiian-electric-customers

Figure D 7 RPS Compliance for Hawaiian Electric 2007-2016 and Customer Sited, Grid Connected Renewables (2012-2016)[126]





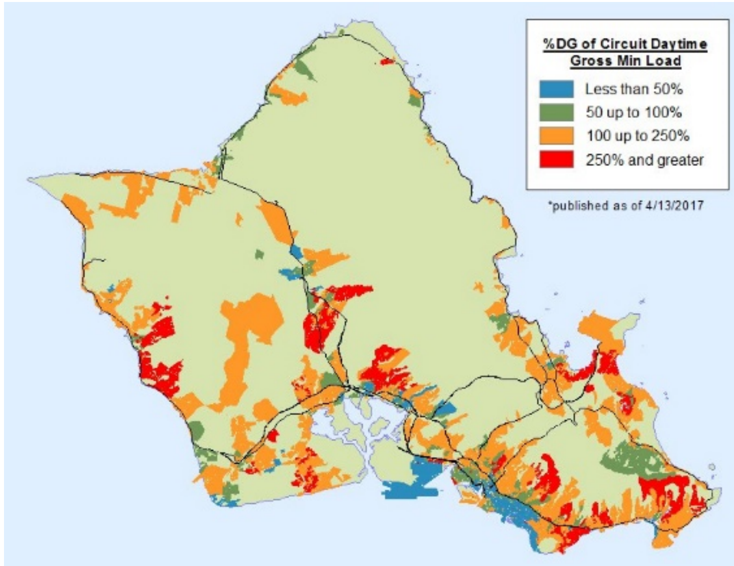
This amount of DG-PV creates a new set of challenges for grid operations. As discussed thoroughly in the PSIP, a new set of challenges requires a new set of tools and methodologies to ensure the reliable delivery of power that is vital to the Hawai'i's economy, security and societal infrastructure. To continue to look forward is necessary, but a sufficient understanding of the grid modernization and DER integration efforts already undertaken in Hawai`i helps to develop an appreciation for the urgency of further investment.

The common practice for sizing of rooftop solar arrays to meet the total annual energy needs of the customer, a practice known as net zero, leads to a variety of grid stability challenges. As depicted in Figure D 8, multiple DG-PV systems sized to be net zero within a dense geographic area overproduce during the day relative to actual customer electricity usage.[127] The overproduction of DG-PV compared to customer electricity demand results in a localized effect on distribution system voltage, which results in problems such as inverters tripping offline or poor power quality to neighboring customers.

[126] https://www.hawaiianelectric.com/about-us/key-performance-metrics/renewable-energy

[127] Hawaiian Electric Companies - Clean Energy Hawaii, Integration Tools and Resources - Locational Value Maps: https://www.hawaiianelectric.com/clean-energy-hawaii/integration-tools-and-resources/locational-value-maps

Figure D 8 O`ahu Map indicating distribution Circuit DER Penetration



The 2014 Distributed Generation Integration Plan[128] "*indicated that the constraining factors for DG under existing technical and operational interconnection requirements are system reliability impacts that arise before most circuit limits are reached. The system reliability constraints are existing issues that must be addressed for the current levels of DG interconnection*."[129] Because of these concerns, grid modernization is a necessary step in evolving Hawai`i's resource portfolio and foundational grid to one capable of meeting the 100 percent renewable generation goal.

It is widely established that conventional distribution systems can accommodate DER up to the circuit hosting capacity with little to no negative impacts on the circuit performance or quality of service. With increasing penetrations of DER, there will be levels at which distribution infrastructure updates will be necessary to prevent undesired impacts, whether they be related to thermal capacity, protection, or voltage management.

Generation on the customer side of the meter with capacity in excess of customer load was never a design consideration for the distribution infrastructure. The assumption of one-way power flow is tightly woven into traditional design standards for equipment application, including conductor sizing and protective systems. Accommodating power flow in the reverse direction can certainly be done, but requires a careful evaluation of all equipment and systems that could be affected.

[128] Docket No. 2011-0206Distributed Generation Interconnection Plan (DGIP); Book 1: http://dms.puc.hawaii.gov/dms/OpenDocServlet?RT=&document_id=91+3+ICM4+LSDB15+PC_DocketReport59+26+A1001001A14H28B70723J1893418+A14H29B53755E976031+14+1960 / DGIP Book 2: http://dms.puc.hawaii.gov/dms/OpenDocServlet?RT=&document_id=91+3+ICM4+LSDB15+PC_DocketReport59+26+A1001001A14H29B41032D5443718+A14H29B53755G359911+14+1960

[129] DGIP Book 1, p. 5

The injection of power from DG-PV systems located long distances from the distribution substation can create high voltages, sometimes owing to smaller distribution circuit conductors at these remote locations. Variability in the output of DG-PV systems over short time frames – seconds to minutes – is generally much more drastic on a kW basis than customer demand, and creates fluctuating voltages that degrade the quality of service to nearby customers. Accommodating high penetrations of existing DG-PV on many distribution circuits, along with the continuous need for upgrades and replacements for aging infrastructure assets, are the immediate challenges for the Companies, and should be addressed through the grid modernization strategy.

VOLT-VAR MANAGEMENT

Traditional Voltage Management Options

On a distribution circuit that serves only customer loads (without DG-PV), the voltage along the feeder decreases from the sending end to the farthest customer due to the current flow towards the customer and the inherent resistance of power lines. At points farther down the feeder, the voltage may drop below acceptable ranges. As a response, utilities typically employ the following countermeasures:

- Balancing load across phases equally, to avoid excessive voltage drop along a single phase during peak loads;
- Increasing the size of conductors (reconductoring) can reduce the effective voltage drop along the lines;
- Increasing the (rated) service voltage along the primary voltage (e.g., 21kv, 12kV or 4kV) segments of the feeder, which reduces the amount of current flowing along the lines and the resistive voltage drop[130];
- Utilizing load tap changing transformers at the substation to ensure that the voltages at on the feeder head or at the feeder load center remains within a target voltage band, regardless of subtransmission voltage variation or downstream loading;
- Adding line regulators to ensure that the voltages at preset points along the feeder are maintained at a target value; and
- Installing capacitor banks to inject reactive power to increase voltage at selected locations, countering the natural voltage drop.

Distribution planners traditionally have employed these options in combination to solve the voltage problems associated with serving growing loads on the distribution system.

[130] Changing the voltage level also requires replacing customer transformers so that they receive the same voltage at their service entrance.

Accommodating Distributed PV Generation

Rather than creating a voltage drop, active power injected by distributed generation creates a corresponding voltage rise across the distribution circuit. The magnitude of the voltage rise, like the load-induced voltage drop, is related strongly to the current flowing from DG-PV and the resistance of distribution lines. In small concentrations, less than or equal to load in a given area, the addition of PV generation can have a generally positive effect. However, this condition is rare for a few reasons:

- Relative sizing of PV systems generally exceeds that of the customer load because of the concentration of PV energy that must be delivered over fewer (daylight) hours than that of load. As customers attempt to offset more of their (energy) load, the peak of the solar output becomes much greater than that of the load.
- Timing of PV generation differs from that of load by several hours. PV peaks are generally centered around 12PM (subject to the azimuth orientation of the array) while customer (particularly residential) loads are near their minimum values in most locations.
- Variability of PV and load locally increases the dynamic variation in the combined load and generation, increasing the likelihood of severe mismatches in load and generation.

These issues are the most pronounced at the local (customer) level. However, as PV penetration increases, these effects will influence voltages at other customers on the same transformer, and even along the medium voltage portions of the distribution circuit.

Distributed generation is interconnected to the distribution grid utilizing inverters that ensure the power being fed into the grid is regulated for safety issues associated with uncontrolled power input. However, most of the older inverters are capable of only producing real power and they were never intended to provide grid support features. In fact, as soon as there is a grid disturbance, the inverters are designed to go offline quickly to isolate the devices from participating negatively or interfering with grid operations. In addition, if grid voltage drops below a certain level, the inverters instantly drop off the grid to prevent unwanted interactions. The interconnection requirements of DG-PV continue to evolve as the technology embedded within modern inverters advances, and as the needs of the grid become more urgent. Today's standard includes ride-through functionality, as well as reactive power support.

The timing of these technological advances has resulted in an abundance of legacy inverters with outdated functionality, which can be counterproductive to grid reliability, as is the case where PV will shut down during an underfrequency event thereby creating additional instability. As part of our December 2016 PSIP, the estimated the capacity interconnected by legacy frequency ride-through settings is shown in Table D 3.

Table D 3 Recreation of Table 0-4 from the December, 2016 PSIP – Legacy PV Capacities

Island	O`ahu	Hawai`i	Maui	Moloka`i	Lana`i
Size PV Systems (kW) @ 59.3 Hz	73,499	7,940	7,205	1,100	96
Size PV Systems (kW) @ 60.5 Hz	215,878	56,600	76,656	1,100	464

Traditional Solutions for Voltage Management with Distributed Resources

Though the problem of voltage rise due to distributed generation is technically opposite of voltage drop due to load, some of the same traditional solutions remain effective:

- Increasing the size of conductors (or reconductoring) reduces the resistance of the lines and the associated voltage rise near the DG location.
- Increasing the (rated) service voltage along the medium voltage segments of the feeder, which reduces the amount of current flowing along the lines and the resulting voltage rise from the addition of (reverse) power flow.

Other regulating devices, such as LTCs load tap changers and line regulators, are somewhat effective at managing distribution voltage with PV. They can respond to DG-PV induced voltage change at the medium-voltage level, but:

- Regulators cannot respond to localized voltage issues at the distribution transformer or individual customer level. Depending on the amount of local PV generation, these voltages may be much higher than at the nearby locations on the medium voltage backbone.
- The variable nature of PV generation, even when smoothed across an entire distribution circuit footprint, may create a significant number of additional regulator "operations" where the regulator tap moves between windings. This could cause premature failure of the device and additional cost.

Smart PV Inverter for Voltage Management

Many modern PV inverters have the capability to react to grid conditions (such as steady-state voltage) and adapt their output accordingly. These advanced inverters can utilize this capability to support the grid. Since 2008, industry-wide efforts have discussed the prospect of standardizing grid support capability from inverters into a variety of "functions." National efforts such as IEEE 1547, as well as state efforts in California and Hawai`i, share a common set of advanced inverter functions for managing grid voltage, including:

- **Power Factor Control** – the inverter absorbs reactive power (to reduce voltage) proportionally to its (active) power output
- **Volt-var** – the inverter absorbs or injects reactive power proportionally to the measured voltage at its terminals.
- **Volt-watt** – the PV inverter reduces its active power injection as grid voltage rises above a pre-determined threshold.

Modeling and simulation of advanced inverters with these features has shown that, when configured properly, these devices may increase the hosting capacity of distribution circuits with no legacy (non-advanced inverters) already installed; however the utility must be aware of increased var demand and losses that may result from the use of these reactive power functions. This effect also has the benefit of being localized near the likely source of a voltage problem (at the point of interconnection of the distributed generator). Advanced inverter functions, particularly Volt-var, offer a number of potential settings in order to optimize their performance. But, because inverters typically limited on total apparent power output, the inverter may need a slightly higher rating to avoid limiting PV generation in certain instances.

In practice, there are several combinations of settings that produce a beneficial result. Default settings have been proposed as part of California Rule 21 and IEEE 1547 and the Companies are proposing settings as a result of research conducted with the NREL.[131] Recent analysis has shown that these settings would have been generally neutral-to-positive across a range of distribution feeders. However, some settings may negatively impact voltages at the customer or aggravate other voltage management devices, such as load tap changers or line regulators. This requires proper coordination of advanced inverters among several distribution regulating devices that has not been widely studied in the industry thus far.

Mitigating voltage issues leveraging advanced inverter functionality may provide a lower incremental-cost solution. However, there are several factors that need to be considered in using advanced inverters as part of a holistic distribution voltage management system. One potential consequence to reactive voltage regulating advanced inverter functionality are the increased losses and var demand the system may incur. This cost must be balanced with the benefits of voltage regulating functionality. Simulations have shown that advanced inverters can have a benefit to the secondary distribution system. However, measurable improvements in hosting capacity require a large portion of the PV generation on a circuit participate in voltage management through advanced inverter functionality. Unfortunately, in Hawai`i about one-third of residential customers have PV installed with non-advanced inverters.

The Companies will require the voltage management functions of advanced inverters to be activated and autonomously provide supportive voltage management of the secondary side of the distribution circuit. This will prevent further degradation of the secondary voltages.

[131] See, https://www.nrel.gov/esif/partnerships-heco-solar-inverter.html

Var controllers for Voltage Management

Several vendors are offering advanced grid-side power electronics devices, secondary var controllers, to manage distribution voltage. These solutions are designed to be operated on the low-voltage (secondary) side of a distribution transformer, near customer loads. Thus far, these technologies have been designed as smaller, localized versions of larger electronic devices such as static var compensators or line regulators. The Companies have been conducting a pilot project with Varentec as described in Section 5.2.3.1 that has produced promising results. Based on these results, we plan to leverage secondary var controllers to augment customers' advanced inverter functionality when distributed supply resources (DG and/or exporting battery) reach very high levels on specific circuits to provide a scalable, cost-effective solution.

Appendix E: Data Type Availability, Usability and Application Matrix

Table E 1 Data Type Availability, Usability, and Application Matrix

● **Available**		○ **Limited / In Progress**				× **Not Available**			✓ Yes				
		SOURCE							**PURPOSE FOR DATA**				
#	**DATA TYPE**	**UTILITY**	**DER PROVIDER**	**PUC**	**FREQUENCY & ACCURACY**	**AVAILABLE?**	**PUBLIC ACCESS?**	**MACHINE READABLE?**	**SYSTEM PLANNING**	**REGULATORY COMPLIANCE**	**COMMERCIAL USE**	**GRID OPERATIONS**	**MARKET EFFICIENCY**
1	Distribution Capital investment	✓			Planning process Forecasts (ex: 5-10yr forecast period)	●	○	×	✓	✓		✓	
2	Customer data (individual)	✓			Monthly billing 15 minute interval for C&I, hourly for residential is commonly available to customers and their designees	●	×	●	✓	✓	✓	✓	✓
3	DER capacity (existing and queued)	✓	✓	✓	Monthly for interconnection queues, but existing capacity is not well known as DER providers have the most accurate information that is not compiled	●	●	○	✓		✓	✓	✓
4	IEEE 1547 inverter operational information		✓		This data is not yet available, but expected to become available as DER implement IEEE 1547 standards	○	×	○					

● Available		○ Limited / In Progress				× Not Available			✓ Yes					
		SOURCE							PURPOSE FOR DATA					
#	DATA TYPE	UTILITY	DER PROVIDER	PUC	FREQUENCY & ACCURACY	AVAILABLE?	PUBLIC ACCESS?	MACHINE READABLE?	SYSTEM PLANNING	REGULATORY COMPLIANCE	COMMERCIAL USE	GRID OPERATIONS	MARKET EFFICIENCY
5	DER services performance	✓	✓	✓	This data is not yet available, but expected to become available as DER grid services are provided	○	×	×	✓	✓	✓	✓	✓
6	Distributed generation adoption forecasts	✓	✓	✓	Planning process	●	●	×	✓	✓		✓	✓
7	Hosting capacity	✓			Monthly updates based on changes reflecting DER interconnections	●	●	●	✓	✓	✓		
8	Hourly DER gross profiles	✓	✓		As recorded by DER provider, utilities do not consistently have this information	●	×	○	✓		✓	✓	
9	Interconnectio n cost data	✓			Utility interconnection tariff (Rule 21), costs are included in rate cases	○	○	×	✓	✓	✓		✓
10	Load growth forecast	✓			Planning process Forecasts	●	●	●	✓	✓			
11	Locational net benefits or value	✓			Utility developed values available to PUC	○	○	○	✓	✓	✓	✓	✓
12	Market potential or saturation studies		✓		Needed for planning process	●	×	×	✓				✓
13	Planned resiliency and reliability projects	✓			Planning process	●	●	●	✓			✓	
14	Project attributes	✓	✓		Planning process	●	●	●	✓			✓	
15	Reliability statistics	✓		✓	Planning process	●	●	○	✓	✓		✓	
16	Utility rates	✓		✓	General ratemaking	●	●	○		✓			✓
17	Voltage & power quality	✓			Planning process	●	×	○	✓	✓		✓	✓

Appendix F: Commission Order Cross Reference

Commission Order Guidance	Grid Modernization Strategy Cross Reference
The commission expects that the strategy will be flexible and able to accommodate changes over time, as the underlying elements, such as technology, customer expectations, and value proposition, continue to evolve.	Flexibility is embedded in the architecture and proportional approach described in Section 3 Grid Modernization Strategy
As the Companies address each of the commission's suggested areas of interest articulated above, the Grid Modernization Strategy should offer a detailed look into the analysis conducted, conclusions reached, and any stakeholder input offered thereon.	**Analysis conducted**: Section 5 Starting Point: Current Status of the Electric Grids; Section 6 Customer-Facing Technologies; 7 Grid-Facing Technologies; Appendix D System Operations and Considerations in a High DER Environment. **Stakeholder Input**: Section 2 Customer & Stakeholder Engagement **Conclusions**: Section 3 Grid Modernization Strategy; Section 4 Integrated Grid Planning & Framework for Cost-Effectiveness; and Section 8 Grid Modernization Roadmap
Further, the Companies should present an overall strategy and grid modernization investment budget that reflects a modular, flexible approach, consistent with the latest industry best practices.	**Strategy**: Section 3 Grid Modernization Strategy **Roadmap/Plan and Investment Budget**: Section 8 Grid Modernization Roadmap

Commission Order Guidance	Grid Modernization Strategy Cross Reference
To that end, the Strategy should identify the discrete grid modernization components that make up the larger strategy and articulate the proposed priority, implementation timing, and expected costs and benefits of each.	**Grid modernization components**: Section 6 Customer-Facing Technologies; and Section 7 Grid-Facing Technologies **Larger Strategy and proposed priority, timing, costs and benefits**: Section 3 Grid Modernization Strategy; and Section 8 Grid Modernization Roadmap
HPUC: "The aim of this process is for the HECO Companies to file a detailed, holistic, and scenario-based Grid Modernization Strategy for each of the utilities".	Aligned with the overall intent and content of this Grid Modernization strategy.
The commission further directs the Companies to identify and address both grid-facing and customer-facing issues related to grid modernization.	**Issues**: Section 4 Integrated Grid Planning & Framework for Cost-Effectiveness; Section 5 Starting Point: Current Status of the Electric Grids; Appendix D System Operations and Considerations in a High DER Environment.
The commission expects the Companies to consider several important factors that may affect the opportunities available for grid modernization in Hawai`i, including, but not limited to, the following:	
1. Cost-effectiveness. The Companies must ensure the cost-effectiveness of grid modernization investments.	**Cost Effectiveness**: Section 4 Integrated Grid Planning & Framework for Cost-Effectiveness
2. Customer protection. The Companies must develop policies that will ensure that all electricity customers, and especially low-income customers, renters, and small business customers, are able to benefit from grid modernization developments to the greatest extent possible.	**Customer Protection (Equitable Approach)**: Section 4 Integrated Grid Planning & Framework for Cost-Effectiveness
3. Customer engagement. The commission expects that achieving the opportunities afforded by grid modernization will require customer engagement, and that the commission, the HECO Companies, and other stakeholders will need to take steps to effectively promote customer engagement.	**Customer Engagement**: Section 2 Customer & Stakeholder Engagement

Commission Order Guidance	Grid Modernization Strategy Cross Reference
4. **Timing. The Companies must consider questions regarding the appropriate time to implement particular grid modernization technologies and practices, especially given the rapid pace at which technologies evolve.**	Timing: Section 4 Integrated Grid Planning & Framework for Cost-Effectiveness; and Section 8 Grid Modernization Roadmap
Additionally, because they provide a platform for future investments in energy delivery infrastructure, primarily, but not limited to, the electric distribution networks owned and operated by the HECO Companies, the Companies' Grid Modernization Strategy should also reflect the following parallel goals:	
• **Modernize the electric distribution system to accommodate two-way flows of energy and energy services through the Companies' networks;**	Section 3 Grid Modernization Strategy; Section 4 Integrated Grid Planning & Framework for Cost-Effectiveness; and Section 8 Grid Modernization Roadmap
• **Enable customer choice of new technologies and services that reduce emissions and improve reliability in a cost efficient manner; and**	Section 2 Customer & Stakeholder Engagement; Section 4 Integrated Grid Planning & Framework for Cost-Effectiveness; and Section 6 Customer-Facing Technologies
• **Provide opportunities for DER to create value**	Section 4 Integrated Grid Planning & Framework for Cost-Effectiveness;
The commission's stated vision of an integrated grid has included goals of more efficient use of energy, deeper penetration of DER, establishment of vibrant markets to transact electric grid services, and adoption of innovative and sustainable energy technologies. These goals are substantial and require a long-term approach comprising incremental steps, each one meant to bring the State toward a cleaner, more resilient and more affordable energy system through the development of dynamic, self-sustaining markets. As a first step, the Companies and stakeholders need to assess and better understand the present status of each island's electric grid.	
"The Companies must consider and provide a specific preliminary definition and guiding principles to inform grid modernization in Hawai`i."	Section 1 Vision, Definition & Scope
HPUC "suggest foundational principles to shape the framework by which a comprehensive strategy should be designed and evaluated."	Section 1 Vision, Definition & Scope; and Section 4 Integrated Grid Planning & Framework for Cost-Effectiveness

Commission Order Guidance	Grid Modernization Strategy Cross Reference
The Legislature has stated: "In advancing the public interest, the commission shall balance technical, economic, environmental, and cultural considerations associated with modernization of the electric grid, based on principles that include but are not limited to:	
1. Enabling a diverse portfolio of renewable energy resources;	Section 4 Integrated Grid Planning & Framework for Cost-Effectiveness
2. Expanding options for customers to manage their energy use;	Section 4 Integrated Grid Planning & Framework for Cost-Effectiveness; and Section 6 Customer-Facing Technologies.
3. Maximizing interconnection of distributed generation to the State's electric grids on a cost-effective basis at non-discriminatory terms and at just and reasonable rates, while maintaining the reliability of the State's electric grids, and allowing such access and rates through applicable rules, orders, and tariffs as reviewed and approved by the commission;	Section 4 Integrated Grid Planning & Framework for Cost-Effectiveness
4. Determining fair compensation for electric grid services and other benefits provided to customers and for electric grid services and other benefits provided by distributed generation customers and other non-utility service providers; and	Section 4 Integrated Grid Planning & Framework for Cost-Effectiveness
5. Maintaining or reliability and modernization of electric grids. enhancing grid safety through the State's electric grids"	Section 4 Integrated Grid Planning & Framework for Cost-Effectiveness; and Section 8 Grid Modernization Roadmap
HPUC: "*identifies the following principles for grid modernization in Hawai`i;*	
• Move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies;	Section 3 Grid Modernization Strategy
• Ensure optimized utilization of electricity grid assets and resources to minimize total system costs;	Section 4 Integrated Grid Planning & Framework for Cost-Effectiveness
• Enable greater customer engagement, empowerment, and options for consuming and providing energy services;	Section 2 Customer & Stakeholder Engagement; Section 4 Integrated Grid Planning & Framework for Cost-Effectiveness; and Section 6 Customer-Facing Technologies

Commission Order Guidance	Grid Modernization Strategy Cross Reference
• **Maintain and enhance the safety, security, reliability, and resilience of the electricity grid, at fair and reasonable costs, consistent with the State's energy policy goals;**	Section 4 Integrated Grid Planning & Framework for Cost-Effectiveness
• **Facilitate comprehensive, coordinated, transparent, and integrated distribution system planning.**	Section 4 Integrated Grid Planning & Framework for Cost-Effectiveness
Current Status of the Electric Grids	
"The Companies and stakeholders need to assess and better understand the present status of each island's electric grid to better inform which steps must be taken to achieve the State's energy goals."	
• **What grid modernization technologies and practices have the HECO Companies' already explored or implemented, and what plans does each Company have for introducing additional technologies and practices?**	Section 5 Starting Point: Current Status of the Electric Grids; and Appendix D System Operations and Considerations in a High DER Environment
• **To what extent does each of the HECO Companies recent investments in grid modernization affect decisions about future investment in grid modernization?**	Section 3 Grid Modernization Strategy; Section 4 Integrated Grid Planning & Framework for Cost-Effectiveness; and Section 8 Grid Modernization Roadmap
• **What role do existing commission regulations, policies, and practices play in encouraging or discouraging future investments in grid modernization infrastructure?**	Section 4 Integrated Grid Planning & Framework for Cost-Effectiveness; and Section 8 Grid Modernization Roadmap
Grid Architecture and Interoperability	
"There is a need to assess a Hawai`i-specific grid architecture that can actively shape the evolution of the islands' electric grids rather than to passively allow grid evolution in a bottom-up manner. In addition, open standards and interoperability must be viewed as foundational components of the integrated grid."	
• **How might the Companies' grid architecture be developed to leverage smart technologies and intelligence in order to enhance edge-of-network capabilities?**	Section 3 Grid Modernization Strategy

Commission Order Guidance	Grid Modernization Strategy Cross Reference
• **How should the Companies' grid architecture be designed and optimized to address the elements of interoperability, cybersecurity, flexibility, and adaptability? More specifically, what are the advantages and disadvantages of a grid system design where the sensing network and related communications infrastructure are viewed as core investments decoupled from specific applications, e.g., AMI?**	Section 3 Grid Modernization Strategy; Section 4 Integrated Grid Planning & Framework for Cost-Effectiveness; and Section 8 Grid Modernization Roadmap
• **How might the Companies' grid architecture be considered as a foundational requirement for grid modernization?**	Section 3 Grid Modernization Strategy; Section 4 Integrated Grid Planning & Framework for Cost-Effectiveness; and Section 8 Grid Modernization Roadmap
• **What steps should be taken to promote open, interoperable grid modernization technologies?**	Section 3 Grid Modernization Strategy; and Section 8 Grid Modernization Roadmap
• **What steps might be taken to develop a framework for assessing a project's contribution to the interoperability of the grid?**	Section 4 Integrated Grid Planning & Framework for Cost-Effectiveness; and Section 8 Grid Modernization Roadmap
Grid Architecture	
The Companies should consider how grid modernization investments can be designed and implemented to cost-effectively meet the dual goals of enhancing grid flexibility and resilience.	
• **How might grid modernization investments be designed and implemented to cost-effectively meet the dual goals of enhancing grid flexibility and resilience?**	Section 3 Grid Modernization Strategy; and Section 4 Integrated Grid Planning & Framework for Cost-Effectiveness
Grid-facing technologies	
The commission expects stakeholder workshops to facilitate discussion regarding the capabilities reasonably expected of a modern distribution network, the status of technologies required to enable these capabilities, the regulatory changes that may be necessary to facilitate the development of a modern distribution network, and the steps that the Companies should take to integrate relevant technologies in a strategic and cost-effective manner.	

Commission Order Guidance	Grid Modernization Strategy Cross Reference
• **What are the key grid-facing technologies and practices that the Companies should be implementing to maximize the reliability and efficiency of the grid, while materially enhancing the ability to further integrate DERs?**	Section 3 Grid Modernization Strategy; Section 5 Starting Point: Current Status of the Electric Grids; Section 7 Grid-Facing Technologies; and Section 8 Grid Modernization Roadmap
• **How do grid-facing technologies and practices overlap with customer-facing technologies and practices, such as advanced meters, and to what extent do they need to be coordinated?**	Section 3 Grid Modernization Strategy; Section 4 Integrated Grid Planning & Framework for Cost-Effectiveness; Section 5 Starting Point: Current Status of the Electric Grids; Section 6 Customer-Facing Technologies; Section 7 Grid-Facing Technologies; and Section 8 Grid Modernization Roadmap
Customer-facing Technologies	
The Companies, in conjunction with stakeholders, must assess how customer-facing technologies, practices, and strategies can be used to:	
• **How can customer-facing technologies, practices, and strategies be used to (1) enable customers to manage their electric usage more efficiently and enable maximum customer cost savings; (2) enable customers to harness their electric loads as a responsive resource to meet grid service needs; and (3) further integrate resources such as distributed generation, energy storage devices, and electric vehicles?**	Section 3 Grid Modernization Strategy; Section 4 Integrated Grid Planning & Framework for Cost-Effectiveness; Section 6 Customer-Facing Technologies; and Section 8 Grid Modernization Roadmap
• **What are the appropriate roles for the HECO Companies and stakeholders in identifying and deploying customer-facing technologies to achieve these goals?**	Section 3 Grid Modernization Strategy; Section 4 Integrated Grid Planning & Framework for Cost-Effectiveness; and Section 8 Grid Modernization Roadmap
• **How should the commission and other stakeholders ensure an open and robust market for third-party, customer-facing technology providers and ensure adequate consumer protection?**	Section 4 Integrated Grid Planning & Framework for Cost-Effectiveness;
Implementation Plan	
"The Companies must address the sequence and pace of grid modernization infrastructure investments, including both grid-facing and customer-facing technologies."	

Commission Order Guidance	Grid Modernization Strategy Cross Reference
• **The Companies' strategy should identify grid modernization technologies as discrete components under the overall strategy and specify the anticipated implementation timing for each component, as well as how each component relates to the other(s).**	Section 4 Integrated Grid Planning & Framework for Cost-Effectiveness; and Section 8 Grid Modernization Roadmap
• **How should the Companies determine the appropriate sequencing and timing for implementing various grid modernization technologies and practices?**	Section 4 Integrated Grid Planning & Framework for Cost-Effectiveness; and Section 8 Grid Modernization Roadmap
Costs and Benefits	
"The Companies and stakeholders should examine what might constitute an appropriate framework to evaluate the cost-effectiveness of grid modernization technologies and practices, including an evaluation of hard-to-quantify impacts such as improved reliability, increased customer choice, and reduced environmental impacts."	
• **What is the appropriate framework to evaluate the cost-effectiveness of grid modernization technologies and practices, including grid-facing and customer-facing technologies?**	Section 4 Integrated Grid Planning & Framework for Cost-Effectiveness
• **How should the commission evaluate hard-to-quantify impacts such as improved reliability, increased customer choice, and reduced environmental impacts?**	Section 4 Integrated Grid Planning & Framework for Cost-Effectiveness; and Section 8 Grid Modernization Roadmap